ROCKY MOUNTAIN
MINERAL LAW FOUNDATION
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MINERAL AND ENERGY LAW
Newsletter

Volume XXXVIII, Number 3, 2021

FEDERAL — MINING

Wells Parker, Benjamin Machlis & Kayla Weiser-Burton
– Reporters –

IBLA Clarifies the Ability of Small Miners to Pay Maintenance Fees In Lieu of Filing an Affidavit of Assessment Work

On July 22, 2021, the Interior Board of Land Appeals (IBLA) issued a decision reversing precedent from prior cases concerning the ability of a small miner to pay the maintenance fee for a subject claim rather than filing an affidavit of assessment work. *Jerry L. Crossland*, 197 IBLA 226, GFS(MIN) 3(2021). The case concerned an appeal by Jerry Crossland from a decision issued by the Bureau of Land Management (BLM) Colorado State Office declaring Crossland's mining claim abandoned and void by operation of law because an affidavit of assessment work was not filed for the 2019 assessment year on or before December 30, 2019. *Id.* at 226. The IBLA reversed BLM's decision, finding that Crossland was not required to file an affidavit of assessment work for the 2019 assessment year because he had instead timely paid the maintenance fee for that year. *Id.*

Crossland acquired the mining claim on October 16, 2018, from Jerrolynn and Richard Kawamoto, who had previously filed a small miner waiver certification in accordance with 43 C.F.R. § 3835.1 for assessment years 2013 through 2018, and again for the 2019 assessment year. *Crossland*, 197 IBLA at 229.

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FEDERAL — OIL & GAS

Kathleen C. Schroder
– Reporter –

Onshore and Offshore Leasing "Pause" Enjoined

In *Louisiana v. Biden*, No. 2:21-cv-00778, 2021 WL 2446010 (W.D. La. June 15, 2021), *appeal docketed*, No. 21-30505 (5th Cir. Aug. 17, 2021), the U.S. District Court for the Western District of Louisiana issued a preliminary injunction preventing implementation of the "pause" on onshore and offshore natural gas leasing that was announced in Executive Order No. 14,008, 86 Fed. Reg. 7619 (Jan. 27, 2021). Section 208 of the executive order directed the Secretary of the Interior to pause oil and natural gas leasing on public lands and in offshore waters pending the completion of a comprehensive review and reconsideration of federal oil and gas leasing practices. This pause was described in Vol. XXXVIII, No. 1 (2021) of this *Newsletter*.

Following issuance of the executive order, the U.S. Department of the Interior (Interior) canceled one lease sale and halted another sale under the Outer Continental Shelf Lands Act (OCSLA). Additionally, Interior canceled or postponed onshore sales under the Mineral Leasing Act (MLA). *Louisiana*, 2021 WL 2446010, at *13–14.

Thirteen states challenged the pause and cancellations and postponements of lease sales as unreasonably delayed agency action and as arbitrary and capricious in violation of the Admin-

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RENEWABLE ENERGY

Mark D. Detsky, Gabriella Stockmayer, K.C. Cunilio & Rachel Bolt
– Reporters –

New IRS Notice Clarifies Extension of Continuity Safe Harbor for Qualified Wind, Solar, and Other Types of Energy Projects

On June 29, 2021, the Internal Revenue Service (IRS) issued Notice 2021-41, which addresses the "beginning of construction" requirement that is applicable to renewable energy projects that may qualify for either the investment tax credit (ITC) or the federal production tax credit (PTC). The ITC is a corporate tax credit for commercial solar photovoltaic (PV) systems and solar thermal technologies. 26 U.S.C. § 48(a)(3)(A). The PTC is a corporate tax credit for wind energy development and other eligible renewable sources (per kilowatt hour of energy sold in the decade after the project's in-service date). *Id.* § 45. The beginning of construction requirement is central to whether a qualified facility project qualifies for either the ITC or the PTC in a given tax year.

The IRS regularly issues notices and guidance to taxpayers concerning substantive rulings and determinations regarding certain provisions of the federal tax code through the Internal Revenue Bulletin (IRB). The Treasury Department and IRS have published several notices through the IRB over recent years regarding the beginning of construction requirement for wind and solar projects. IRS Notice 2013-29 provided two different methods for a project developer to meet the beginning of construction requirement under either section 45 or 48(a)(5).

The first requirement is the "Physical Work Test." IRS Notice 2013-29 addresses the Physical Work Test as follows:

> Construction of a qualified facility begins when phyical work of a significant nature begins. . . . Whether a taxpayer has begun construction of a facility before

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Upon acquisition of the claim, Crossland did not file an affidavit of assessment work with BLM in 2019, but instead elected to pay the maintenance fee for assessment years 2019 and 2020. *Id.* On April 1, 2020, BLM declared the mining claim abandoned and void by operation of law because while a maintenance fee waiver certification was filed for the 2019 assessment year, the requisite affidavit of assessment work was never received. *Id.* at 230. Crossland timely appealed BLM's decision, stating that after the claim was acquired in 2018, he had timely paid the required maintenance fee for the 2019 assessment year because he had not filed a maintenance fee waiver certification. *Id.*

The question presented on appeal was whether Crossland—who also qualified for the small miner waiver when he acquired the claim—had the option to pay the maintenance fee for the assessment year in which he had acquired the claim, after his predecessors had already received a waiver for that same year. *Id.* at 234. The IBLA examined the following statement from a previous case, that "[a] transferee who qualifies for [a small miner] waiver does not have the option of paying the maintenance fee." *Id.* (first alteration in original) (quoting *Frank E. Sieglitz*, 170 IBLA 286, 291, GFS(MIN) 28(2006)). However, the IBLA here declined to follow this precedent. The IBLA found that the statement from *Sieglitz* was dictum and lacked statutory and regulatory support. *Id.* at 236–37. Moreover, the IBLA found that the statement was seemingly at odds with the statutory scheme crafted by Congress, which carved out an exception for paying the requisite maintenance fees for those owners that qualified for the small miner waiver, but never required those same owners to seek a waiver. *Id.* at 238. Accordingly, the IBLA expressly disavowed the statement from *Sieglitz* and reversed BLM's decision, finding that Crossland's 2019 payment was in lieu of the assessment work. *Id.* at 239.

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istrative Procedure Act (APA). *See Id.* at *11 (citing 5 U.S.C. § 706). The plaintiffs also argued that the pause was a substantive rule for which Interior did not offer notice and comment as required by the APA. *Id.*

Several of the issues in the case turned on provisions of OCSLA and the MLA. OCSLA directs that the Secretary of the Interior "shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of [OCSLA]." 43 U.S.C. § 1344(a). The leasing program "shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which [Interior] determines will best meet national energy needs for the five-year period following its approval or reapproval." *Id.* The MLA directs the Secretary to hold, at a minimum, quarterly lease sales for each state where eligible lands are available. 30 U.S.C. § 226(a).

Initially, the court examined whether the plaintiffs' causes of action under the APA were reviewable. The United States had argued that the plaintiffs challenged "interim postponements" of lease sales, rather than decisions to forgo sales entirely. *Louisiana*, 2021 WL 2446010, at *12. The court disagreed, finding that the challenged decisions were "final agency action." *Id.* at *12–13. The court also rejected the United States' contention that its actions were unreviewable because they were legally committed to agency discretion. *Id.* at *13–14 (citing 5 U.S.C. § 701(a)(2)). The court found that "[t]he discretion to pause a lease sale to eligible lands is not within the discretion of the agencies by law under either OSCLA [sic] or MLA." *Id.* at *13.

The *Mineral and Energy 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); 2021 price—$110 per year.

Having made these threshold determinations, the court then concluded that the plaintiffs satisfied one substantive prerequisite to a preliminary injunction—a likelihood of success on the merits. The court concluded the pause violated both OCSLA and the MLA. *Id.* at *17–18. The court reasoned that "[n]either OCSLA nor MLA gives [Interior] authority to pause lease sales" but rather "[t]hose statutes require that [Interior] continue to sell eligible oil and gas leases . . . ." *Id.* at *18.

Additionally, the court found the pause to be arbitrary and capricious in violation of the APA because Interior did not explain the rationale for the pause. "A command in an Executive Order does not exempt an agency from the APA's reasoned decisionmaking requirement." *Id.*

Moreover, the court held that the pause was a substantive rule issued without notice and public comment. *Id.* at *19. The court reasoned that the executive order "effectively commands that [Interior] stop performing its obligations under OCSLA and MLA to sell oil and natural gas leases" without discretion to depart from the executive order's requirements. *Id.*

Finally, the court held that the plaintiffs were likely to succeed in their claim that Interior unlawfully withheld or unreasonably delayed the lease sales that were canceled or postponed in response to the executive order. *Id.* at *21.

After finding the plaintiffs met the other preliminary injunction elements, *id.* at *21–22, the court enjoined and restrained Interior from implementing the pause with respect to the two challenged offshore lease sales and all onshore lands eligible for leasing, *id.* at *22.

The United States has appealed this decision to the U.S. Court of Appeals for the Fifth Circuit.

Federal Oil and Gas Leases in Greater Sage-Grouse Habitat Remanded for Further NEPA Analysis

In *Western Watersheds Project v. Bernhardt*, No. 1:18-cv-00187, slip op. (D. Idaho June 9, 2021), the U.S. District Court for the District of Idaho remanded oil and gas leases sold at the Bureau of Land Management's (BLM) February 2017 Wyoming, June 2017 Wyoming, June 2017 Montana, and September 2017 Wyoming sales. The court found that BLM did not adequately analyze impacts to greater sage-grouse as required by the National Environmental Policy Act (NEPA) prior to offering the parcels for lease. *Id.* at 51.

The decision addresses the second phase of this case. In the first phase, the court vacated portions of a BLM instruction memorandum setting forth leasing procedures and certain federal oil and gas leases issued in accordance with these procedures. *See W. Watersheds Project v. Bernhardt*, 441 F. Supp. 3d 1042 (D. Idaho 2020); Vol. XXXVII, No. 2 (2020) of this *Newsletter*.

In the second phase of the case, the court found multiple flaws in BLM's NEPA analysis. First, the court held that BLM should have considered the alternative of deferring leases in greater sage-grouse priority habitat management areas (PHMAs). *W. Watersheds Project*, No. 1:18-cv-00187, slip op. at 23. For each of the lease sales, BLM had prepared an environmental assessment (EA), in which BLM analyzed alternatives of leasing all proposed parcels and leasing no parcels (the "no action" alternative). *Id.* at 25. In comments, the plaintiffs advocated that BLM defer leasing parcels in either PHMAs or both PHMAs and general habitat management areas. *Id.* at 27. The court found BLM's responses to these comments lacking, holding that "BLM violated NEPA by failing to provide an adequate explanation of why it failed to consider the reasonable alternative of deferring priority greater sage-grouse habitat." *Id.* at 29.

Second, the court held that, prior to leasing, BLM failed to assess baseline conditions for the greater sage-grouse, such as population trends, the number of existing leases, and the amount of anthropogenic development. *Id.* at 30–34. The court examined both the EAs prepared for the lease sales and the environmental impact statements (EISs) associated with the underlying resource management plans (RMPs). The court determined the EAs were insufficient because they only provided "a simple snapshot inventory of involved greater sage-grouse parcels." *Id.* at 32. Further, the court found the RMP EISs inadequate, determining they "merely provide an overview of the general condition of greater sage-grouse across each planning area" and did not examine information such as individual leks or populations in lease sale areas. *Id.* at 33.

Third, the court held that BLM did not adequately analyze the impacts of leasing on greater sage-grouse. Despite finding that the leasing EAs "[spoke] generally to the impacts of the [lease sales] on greater sage-grouse," *id.* at 37, the court found that BLM had access to more detailed information regarding sage-grouse lek locations, lek counts, and the amount of existing habitat disturbance that "could have informed a more site-specific impacts analysis," *id.* at 40.

Finally, the court held that BLM failed to take a hard look at the cumulative impacts of leasing on greater sage-grouse. *Id.* at 43–47. The court acknowledged that the RMP EISs discussed cumulative impacts but explained that the RMP EISs did not disclose the incremental impact of the lease sales or consider how the collective effects of the lease sales combine alongside other actions and conditions to affect greater sage-grouse. *Id.* at 44, 46.

The court remanded the leases to BLM for further NEPA analysis and, in the interim, enjoined BLM from issuing new applications for permits to drill and approving further surface disturbing activities. *See id.* at 47–49. The court declined to vacate the leases because of the possibility that, after preparation of additional NEPA analysis, BLM could stand by its decision to issue the challenged leases. *Id.* at 48–49.

Both the United States and intervenor-defendant Western Energy Alliance have appealed this decision to the U.S. Court of Appeals for the Ninth Circuit. *See W. Watersheds Project v. W. Energy All.*, No. 21-35648 (9th Cir. filed Aug. 10, 2021).

District of New Mexico Upholds APDs in Mancos Shale

In *Diné Citizens Against Ruining Our Environment v. Bernhardt*, No. 1:19-cv-00703, slip op. (D.N.M. Aug. 3, 2021), the U.S. District Court for the District of New Mexico declined to enjoin oil and gas activities in the Mancos Shale. This ruling was the latest chapter in a long-running dispute over development of the Mancos Shale in New Mexico. *See Diné Citizens Against Ruining Our Env't v. Bernhardt*, 923 F.3d 831 (10th Cir. 2019); Vol. XXXVI, No. 2 (2019) of this *Newsletter* (Environmental Issues report).

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.

Previously, the U.S. Court of Appeals for the Tenth Circuit had vacated findings of no significant impact (FONSIs) associated with five environmental assessments (EAs) because the EAs did not adequately analyze the cumulative impacts of approving applications for permits to drill (APDs) on water resources. *Diné Citizens*, No. 1:19-cv-00703, slip op. at 3.

The plaintiffs challenged 370 APDs that were covered by a supplemental EA prepared in response to the Tenth Circuit decision (the "EA Addendum"). *Id.* at 4. The EA Addendum supplemented the Bureau of Land Management's (BLM) analysis in 81 EAs and addressed potential impacts to a variety of resources, including greenhouse gas impacts. *Id.* The plaintiffs, however, only sought to preliminary enjoin and temporarily restrain oil and gas development related to APDs covered by 32 EAs. *Id.* at 3. Ultimately, the district court denied the plaintiffs' request for preliminary injunction and dismissed all the plaintiffs' claims as without merit. *Id.* at 63–64.

After rejecting the plaintiffs' argument that the court should not consider the EA Addendum when evaluating the adequacy of the National Environmental Policy Act (NEPA) analysis, *see id.* at 16–27, the court upheld BLM's NEPA analysis. Most significantly, the court upheld BLM's consideration of greenhouse gas impacts. The court determined that BLM reasonably conducted a 100-year analysis of the environmental effects of greenhouse gas emissions, rather than the 20-year schedule that the plaintiffs championed. *Id.* at 56–57. Additionally, the court upheld BLM's assessment of cumulative impacts to climate change. *Id.* at 58–60. The court also rejected the plaintiffs' argument that BLM should have analyzed greenhouse gas emissions in the context of carbon budgets. *Id.* at 60–62.

Additionally, the court disagreed with the plaintiffs' arguments that BLM did not adequately analyze impacts to water resources. The court found that BLM appropriately analyzed both water consumption from wells completed with slick water and impacts associated with groundwater use. *Id.* at 39–43.

Similarly, the court upheld BLM's analysis of air quality impacts. The plaintiffs had argued that BLM's analysis did not consider impacts of anticipated air emissions on public health, incorrectly characterized air pollutants as a "temporary nuisance," and inappropriately deferred to the National Ambient Air Quality Standards rather than the American Lung Association's ozone rating to assess risks from ambient ozone levels. *See id.* at 43–54. The court characterized these arguments as "a misreading of BLM's NEPA documentation." *Id.* at 44.

Having found that the plaintiffs did not satisfy all of the elements for preliminary relief, the court denied the preliminary injunction. *Id.* at 63–64. Furthermore, having evaluated the merits of the plaintiffs' objections, the court then determined that further briefing or evaluation would not aid its decision making. Accordingly, the court dismissed the plaintiffs' claims entirely. *Id.* at 64.

IBLA Finds Processing Fee a Jurisdictional Requirement in Appeals of BSEE Decisions

In *Petro Ventures, Inc.*, 197 IBLA 212, GFS(OCS) 298(2021), the Interior Board of Land Appeals (IBLA) dismissed appeals of decisions of the Bureau of Safety and Environmental Enforcement (BSEE) because the appellant did not submit a separate processing fee for each appeal. Petro Ventures, Inc. (Petro Ventures) had appealed four separate decisions assessing civil penalties that BSEE issued on the same day. To do so, Petro Ventures had filed one notice of appeal that attached all four decisions and paid a single processing fee. BSEE moved to dismiss all of Petro Ventures' appeals for failing to comply with the regulation governing appeals of BSEE decisions. *Id.* at 212–14.

BSEE's regulation at 30 C.F.R. § 290.4 specifies how to appeal a BSEE decision. *Petro Ventures*, 197 IBLA at 217. It provides that BSEE must receive a written notice of appeal with a copy of the decision and a $150 nonrefundable processing fee within 60 days of the appellant's receipt of the appealed decision. *Id.*

The IBLA construed this regulation and concluded that the processing fee is a jurisdictional requirement that must be satisfied for each appealed decision. *Id.* at 217–22. As a result, an appellant cannot cure a failure to submit a processing fee once the 60-day period has passed. *Id.* at 219–22. The IBLA accordingly dismissed three of the four appeals at issue.

The filing fee was the only procedural error identified by the IBLA. The IBLA found no error in Petro Ventures' submission of one notice of appeal for all four appeals. *Id.* at 215–17. The IBLA also found no error in the fact that a copy of the notice of appeal arrived at the Solicitor's Office two days after the 60-day deadline because Petro Ventures transmitted this copy "concurrently" with the notice of appeal filed with BSEE, as required by 43 C.F.R. § 4.401(c)(1). *Petro Ventures*, 197 IBLA at 222–24.

IBLA Sets Aside BSEE Civil Penalty That Considered Affiliates' Prior Compliance History

In *Fieldwood Energy, LLC*, 197 IBLA 169, GFS(OCS) 296(2021), the Interior Board of Land Appeals (IBLA) set aside a portion of a Bureau of Safety and Environmental Enforcement (BSEE) decision assessing a $175,000 civil penalty on Fieldwood Energy, LLC (Fieldwood) for failing to pressure test an entire blow-out preventer system used in connection with offshore operations on an oil and gas lease on the Outer Continental Shelf. The IBLA found that BSEE improperly increased the penalty amount based on the compliance history of Fieldwood's affiliates that predated Fieldwood's acquisition of these entities.

BSEE imposed a civil penalty of $35,000 per day for a five-day assessment period. *Id.* at 178. The Office of Natural Resources Revenue's civil penalty guidance (Civil Penalty Matrix) specified a range of civil penalties of $15,000–$40,000 per day based on the nature of the violation and identified $25,000 per day as a "starting point" for an assessment. *Id.* at 174.

BSEE, however, increased the $25,000 per day starting assessment because of the compliance records of four other companies that Fieldwood acquired. *Id.* at 175, 177. BSEE found that these companies had a total of eight civil penalty cases during the two-year period immediately preceding the violation at issue. *Id.* at 177. Fieldwood appealed the penalty on multiple grounds, including that BSEE improperly increased the penalty by $10,000 per day based on compliance incidents that predated Fieldwood's affiliation with the four other companies. *Id.* at 186.

In its decision, the IBLA recognized that no published IBLA decision addressed "whether BSEE properly relies on the civil penalty case history of a violator's affiliates to increase the civil penalty assessed against the violator." *Id.* at 187. The IBLA then determined that neither the Outer Continental Shelf Lands Act (OCSLA) nor its implementation regulations support basing a penalty against one entity on the civil penalty history of its affiliates that predates the entities' affiliation. *Id.* at 188. The IBLA found "the statute and regulations focus exclusively on the violator." *Id.* The IBLA similarly construed BSEE's guidance interpreting OCSLA and its regulations. *Id.* Accordingly, the IBLA set aside BSEE's decision to increase civil penalties. *Id.* at 189–90.

IBLA Limits ONRR's Authority to Require Inspection Fees for Offshore Oil and Gas Facilities

In *Medco Energi US LLC*, 197 IBLA 199, GFS(OCS) 297(2021), the Interior Board of Land Appeals (IBLA) reversed a decision of the Director of the Office of Natural Resources Revenue (ONRR) upholding orders requiring Medco Energi US LLC (Medco) to pay fees of $762,500 for inspections by the Bureau of Safety and Environmental Enforcement (BSEE) of oil and gas facilities on the Outer Continental Shelf. *Id.* at 199–201. The IBLA held that, at the time ONRR issued the orders, ONRR lacked statutory authority to demand such fees.

In accordance with the Outer Continental Shelf Lands Act (OCSLA), BSEE's regulations require it to conduct inspections of offshore oil and gas facilities. *Id.* at 200 (citing 43 U.S.C. § 1348(c); 30 C.F.R. § 250.130). "[S]ince 2010, Congress has directed the Secretary to collect non-refundable inspection fees from the designated operators of facilities subject to inspections under the OCSLA and established those fees in its annual appropriations legislation for each fiscal year." *Id.* at 201.

ONRR issued the appealed orders in January 2017 and January 2018. *Id.* At that time, ONRR was funded by continuing appropriations acts. *Id.* at 202. These acts only authorized funding at "[s]uch amounts as may be necessary, at a rate for operations as provided in the applicable appropriations [a]cts for [the prior fiscal year] and under the authority and conditions provided in such [a]cts, for continuing projects or activities . . . that are not otherwise specifically provided for in this Act . . . ." *Id.* (first and third alterations in original) (quoting Continuing Appropriations and Military Construction, Veterans Affairs, and Related Agencies Appropriations Act, 2017, and Zika Response and Preparedness Act, Pub. L. No. 114-223, div. C, § 101(a), 130 Stat. 857 (2016); Continuing Appropriations Act, 2018 and Supplemental Appropriations for Disaster Relief Requirements Act, 2017, Pub. L. No. 115-56, div. D, § 101(a), 131 Stat. 1129 (2017)). Congress did not enact consolidated appropriations acts for fiscal years 2017 and 2018 until May 2017 and March 2018, respectively. *Id.*

The IBLA analyzed the language of the continuing appropriations acts and the underlying consolidated appropriations acts and concluded they did not authorize collection of inspection fees for fiscal years 2017 and 2018. *Id.* at 207–10. The IBLA determined that the consolidated appropriations acts for 2016 and 2017, which the continuing appropriation acts for 2017 and 2018 extended, only authorized collection of inspection fees for one fiscal year. *Id.* at 208. The IBLA further determined that Congress did not authorize collection of inspection fees for 2017 and 2018 until it enacted consolidated appropriations acts for those years. *Id.* at 209. Therefore, the IBLA reversed the ONRR Director's decision. *Id.* at 211.

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> [the statutory deadline] will depend on the relevant facts and circumstances. The [IRS] will closely scrutinize a facility, and may determine that construction has not begun on a facility before [the statutory deadline] if a taxpayer does not maintain a continuous program of construction as determined under section 4.06.

Id. § 4.01. Regarding the Physical Work Test, a qualified project must maintain continuous construction of the facility, which is known as the "Continuous Construction Test."

The other requirement is the "Five Percent Safe Harbor," which is defined within Notice 2013-29 as follows:

> Construction of a facility will be considered as having begun before [the statutory deadline] if (1) a taxpayer pays or incurs (within the meaning of Treas. Reg. § 1.461-1(a)(1) and (2)) five percent or more of the total cost of the facility, except as provided in section 5.01(2), before [the statutory deadline], and (2) thereafter, the taxpayer makes continuous efforts to advance towards completion of the facility (as determined under section 5.02).

Id. § 5.01. Regarding the Five Percent Safe Harbor, a qualified project must maintain continuous efforts to advance the facility towards completion, which is known as the "Continuous Efforts Test."

Both of these methods obligate a renewable project developer to work to continuously complete construction of a facility once construction has been commenced, which is referred to as the "Continuity Requirement." The IRS has extended this specified time period several times.

Previous IRS guidance provided developers seeking to satisfy the Continuity Requirement with a safe harbor provision known as the "Continuity Safe Harbor." The Continuity Safe Harbor permits an eligible project to claim either the ITC or PTC if the project is placed into service within a certain time frame that begins in the tax year that the project's construction began. *See* Press Release, IRS, "Treasury, IRS Extend Safe Harbor for Renewable Energy Projects" (June 29, 2021). Historically, a project put into service no more than four years after the year that project construction commenced would be deemed to satisfy the requirement. If a qualified project is unable to meet the Continuity Safe Harbor, a project developer is eligible to meet the Continuity Requirement if the developer is able to satisfy either the Continuous Efforts Test or Continuous Construction Test.

However, as a result of the COVID-19 pandemic, many renewable energy projects have faced significant delays, stemming from supply chain interruptions and workforce limitations. COVID-19 delays have led many project developers to be unable to place renewable energy projects into service in the time frame needed to meet the Continuity Safe Harbor. In response, in June 2020 the IRS issued Notice 2020-41, which extended the Continuity Safe Harbor from four to five years for any qualified project that began construction in 2016 or 2017.

IRS Notice 2021-41 further extended the Continuity Safe Harbor to six years for projects that commenced construction in 2016, 2017, 2018, or 2019. It also extended the Continuity Safe Harbor to five years for projects that began construction in 2020. Notice 2021-41 is intended to offer relief in response to the "extraordinary delays" due to COVID-19 of placing into service renewable facilities that are eligible for either the ITC or PTC.

New Office of Public Participation Created Within FERC

In 1978, the Federal Power Act was amended to add section 319, which directs the Federal Energy Regulatory Commission (FERC) to create the Office of Public Participation (OPP). 16 U.S.C. § 825q-1(a). Pursuant to the Act, the OPP is to serve two main purposes. First, the OPP is required to "coordinate assistance to the public with respect to the authorities exercised by [FERC]" and coordinate assistance for intervenors and those seeking to participate or intervene in FERC proceedings. *Id.* § 825q-1(b)(1). Second, the OPP may, pursuant to rules promulgated by FERC, provide funding, including attorney's fees, expert witness fees, and other costs, "to any person whose intervention or participation substantially contributed to the approval, in whole or in part, of a position advocated by such person." *Id.* § 825q-1(b)(2). Such compensation is available when FERC determines that the proceeding is significant and that "such person's intervention or participation in such proceeding without receipt of compensation constitutes a significant financial hardship to him." *Id.*

However, just a year after passing section 319 and directing FERC to create the OPP, Congress passed an appropriations bill that removed FERC's authority to use funds provided in the appropriation to compensate intervenors. *See* Energy and Water Development Appropriation Act, 1980, Pub. L. No. 96-69, 93 Stat. 437 (1979). For over 40 years thereafter, FERC did not move forward with creating the OPP—until now. In December 2020, Congress directed FERC to provide a report, by June 25, 2021, detailing how it will establish and operate the OPP as required under section 319. *See* 166 Cong. Rec. H8311, 8378 (daily ed. Dec. 21, 2020).

On June 24, 2021, after engaging in a public comment process, FERC released its report summarizing the OPP's organization, role, and implementation. *See* FERC, "FERC Report on the Office of Public Participation" (June 24, 2021). According to the report, commenters at the public sessions stressed that the OPP needed to assist the public, especially members of underrepresented communities, in engaging in often complicated FERC proceedings, and that this assistance would help ensure these communities are on equal footing with industry groups that have greater access to resources. *Id.* at 8.

Based on these comments, FERC stated that the mission of the OPP is to "coordinate and provide assistance to members of the public to facilitate participation in [FERC] proceedings." *Id.* at 10. To accomplish this mission, the report outlined five functions of the OPP: (1) to engage "with the public through direct outreach and education to facilitate greater understanding of [FERC] processes and solicit broader participation"; (2) to act as a liaison to the public by providing information on individual proceedings and responding to requests for technical assistance; (3) to coordinate with other FERC offices to improve FERC processes in response to public comment to ensure they are "inclusive, fair, and easy to navigate"; (4) to provide advice to FERC on intervenor funding; and (5) to collaborate with other FERC offices to ensure that "the concerns of Tribal members, environmental justice communities, and other historically marginalized communities are fully and fairly considered in [FERC] proceedings." *Id.* According to the report, FERC intends to establish the OPP in fiscal year 2021 and grow the office over four years, reaching its full operation by the end of fiscal year 2024. *Id.* at 11.

It is unknown how this office will engage with FERC or the ultimate impact it will have on FERC proceedings. However, the OPP could become a public voice at an agency that has not previously had a public advocate. In particular, the office could increase the participation of environmental justice communities and renewable energy advocates in FERC proceedings that were previously inaccessible to individuals and groups that did not have the knowledge or resources of traditional institutional players.

CONGRESS / FEDERAL AGENCIES – GENERAL

John H. Bernetich & Dale Ratliff
– Reporters –

President Biden Signs Joint Resolution to Rescind Trump Administration NSPS OOOOa "Policy Rule" Regarding Methane and VOC Emissions from the Oil and Gas Sector

As reported in Vol. XXXVIII, No. 2 (2021) of this *Newsletter*, the Senate adopted Joint Resolution 14 on April 28, 2021, to disapprove the U.S. Environmental Protection Agency's (EPA) September 14, 2020, amendments to New Source Performance Standard (NSPS) OOOOa under the Congressional Review Act (CRA). On June 30, 2021, following approval in the House of Representatives, President Biden signed the joint resolution into law. *See* Pub. L. No. 117-23, 135 Stat. 295 (2021).

The 2020 amendments to NSPS OOOOa, known generally as the NSPS OOOOa "Policy Rule," effectuated two major changes to the rules governing emissions from new, modified, and reconstructed sources in the oil and natural gas sector: (1) removed the oil and natural gas transmission sector from the purview of the rules, and (2) removed methane as a regulated pollutant under the rules. 85 Fed. Reg. 57,018 (Sept. 14, 2020) (amending 40 C.F.R. pt. 60). In a separate 2020 rulemaking, EPA promulgated technical amendments to NSPS OOOOa that, among other revisions, revised the leak detection and repair requirements for well sites and compressor stations, allowed for optical gas imaging monitoring to demonstrate pneumatic pump closed vent systems are operating with no detectable emissions, removed the requirement for a professional engineer to certify closed vent systems, and articulated the conditions under which averaging of tank battery emissions is permitted for determining storage tank applicability. 85 Fed. Reg. 57,398 (Sept. 15, 2020) (amending 40 C.F.R. pt. 60).

The joint resolution rescinds the Policy Rule in its entirety and reinstates the NSPS OOOOa volatile organic compound (VOC) and methane standards for the transmission and storage segments and the methane standards for the production and processing segments. *See* 5 U.S.C. § 801(f) (When Congress passes a joint resolution of disapproval and the President signs the joint resolution into law, the rule is "treated as though such rule had never taken effect."). The joint resolution did not revoke or otherwise affect the technical amendments.

As previously reported, the reinstatement of the regulation of methane under NSPS OOOOa will trigger EPA's duty to issue an existing source rule for the oil and natural gas source category under section 111(d) of the Clean Air Act. 85 Fed. Reg. at 57,033. Section 111(d) directs EPA to issue "emission guidelines" and require states to submit plans based on the emission guidelines that establish performance standards for existing sources in a source category following promulgation of standards for new, modified, and reconstructed sources in that source category. 42 U.S.C. § 7411(d); 40 C.F.R. § 60.21(e).

As a first step in the regulation of existing sources, EPA will likely revive an information collection request (ICR) repealed by the Trump administration. EPA began the ICR process to gather information on existing oil and gas sources in 2016 as an initial step in establishing section 111(d) emission guidelines for methane. 81 Fed. Reg. 35,763 (June 3, 2016). EPA sought information on what emission controls are being used in the field, how existing controls are configured, the difficulty of replacing or upgrading controls, the time and cost associated with retrofit, whether electricity or generating capacity is available, and how often sites are staffed or visited. *Id.* at 35,764. In March 2017, EPA withdrew the ICR and later announced its intent to review the 2016 NSPS OOOOa. 82 Fed. Reg. 12,817 (Mar. 7, 2017); 82 Fed. Reg. 25,730, 25,731–32 (June 5, 2017). With reinstatement of the 2016 NSPS OOOOa on the horizon, EPA will be required to issue emission guidelines for methane, and regulated entities should expect to receive a similar ICR to facilitate the section 111(d) process.

EPA also released a guidance document discussing the compliance implications of the CRA disapproval of the Policy Rule. *See* EPA, "Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule: Questions and Answers" (June 30, 2021). EPA indicated in that guidance that because the Policy Rule was published prior to the technical amendments, the technical amendments (1) do not apply to the transmission and storage segment; and (2) only apply to the NSPS OOOOa VOC standards, and not the methane standards, for the production and processing segments because the methane standards had been revoked at the time the technical amendments were promulgated. This means that for many of the NSPS OOOOa standards that apply to both VOCs and methane, operators will be required to comply with the 2016 NSPS OOOOa standards to remain in compliance. EPA interprets the joint resolution to mean that the applicable 2016 NSPS OOOOa requirements "came back into effect *immediately* upon enactment of the joint resolution"—i.e., June 30, 2021. *Id.* at 2 (emphasis added). EPA expects owners and operators to take immediate steps to comply with the applicable 2016 standards. *Id.* at 3.

States Seek to Block President Biden's Revamped Social Cost of Carbon Estimates

A coalition of 12 Republican attorneys general asked a federal district court for a preliminary injunction blocking President Biden's update to the federal government's social cost of carbon metrics. *See* Mot. for Prelim. Inj., *Louisiana v. Biden*, No. 2:21-cv-01074 (W.D. La. July 27, 2021), ECF No. 53. The *Louisiana* case followed a separate lawsuit and request for preliminary injunction filed by a different coalition of Republican attorneys general led by Missouri. *See* Mot. for Prelim. Inj., *Missouri v. Biden*, No. 4:21-cv-00287 (E.D. Mo. May 3, 2021), ECF No. 17. The lawsuits challenge interim estimates released in February 2021 by the Interagency Working Group on Social Cost of Greenhouse Gases (IWG). *See* IWG, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates Under Executive Order 13990" (Feb. 2021) (Interim Estimates).

The social cost of greenhouse gases metrics represent a holistic calculation of the costs of carbon dioxide and other greenhouse gas emissions on a rate-per-ton basis. It represents an estimate, in dollars, of the economic damage that would result from emitting one additional ton of greenhouse gases into the atmosphere. *See generally id.*

On January 20, 2021, President Biden issued Executive Order No. 13,990, 86 Fed. Reg. 7037 (Jan. 20, 2021), which directed the IWG to develop interim estimates for the social cost of greenhouse gases within 30 days and to issue final estimates by January 2022. *Id.* § 5(b). The executive order also directed agencies to use the Interim Estimates to value the cost of greenhouse gas emissions from regulations and other relevant agency actions until the final estimates are published. *Id.* § 5(b)(ii)(A). The IWG's Interim Estimates, released in February 2021, effectively revoke changes made by the Trump administration and reinstate estimates in effect during the Obama administration. The Interim Estimates establish an estimated present cost of $17 to $76 per metric ton of carbon dioxide emitted in 2025. *See* Interim Estimates at 5.

In the *Louisiana* case, 12 states assert that the Interim Estimates are unlawful because they consider global impacts of greenhouse gases (rather than only domestic impacts) and use an improper discount rate to calculate the present cost of future emissions, in violation of the Administrative Procedure Act (APA) and numerous federal natural resources and environmental laws. The *Missouri* states assert that by issuing the executive order and Interim Estimates, the President and IWG violated separation of powers principles and the APA by exercising powers reserved by the Constitution to Congress.

The Trump administration's reliance on exclusively domestic damages and use of higher discount rates resulted in cost estimates about seven times lower than the estimates under the Obama administration that are included in the Interim Estimates. *See* Gov't Accountability Office, "Social Cost of Carbon" (GAO-20-254 June 2020). These lower cost estimates, for example, played a pivotal role in allowing the Trump administration to justify its cost-benefit analysis of its proposal to repeal and replace the Obama administration's Clean Power Plan. *See* 84 Fed. Reg. 32,520, 32,571–73 (July 8, 2019) (to be codified at 40 C.F.R. pt. 60). Accordingly, the outcome of these challenges will have a significant impact in the implementation of the Biden administration regulatory agenda.

As of the time of this report, the states' requests for a preliminary injunction remain pending in both the *Louisiana* and *Missouri* cases.

ENVIRONMENTAL ISSUES

Randy Dann, Kate Sanford & Michael Golz
– Reporters –

Ninth Circuit Clarifies EPA's Duties Under the CWA

The U.S. Court of Appeals for the Ninth Circuit recently waded into the ongoing Pebble Mine controversy with an opinion that may hint at a more active role by the U.S. Environmental Protection Agency (EPA) in future section 404 of the Clean Water Act (CWA), 33 U.S.C. § 1344, permitting processes. *See* *Trout Unlimited v. Pirzadeh*, 1 F.4th 738 (9th Cir. 2021).

Although the U.S. Army Corps of Engineers (Corps) administers the section 404 dredge and fill permitting program, EPA can shape the program in fundamental ways. The Corps' section 404 permits specify disposal sites for the discharge of dredged and fill materials. 33 U.S.C. § 1344(a). However, under section 404(c), the EPA Administrator may limit the scope of section 404 permits by "restrict[ing] the use" of certain disposal sites or prohibiting the Corps from specifying certain sites altogether. *Id.* § 1344(c); 40 C.F.R. § 231.2. The CWA authorizes this exercise of discretion "whenever [the Administrator] determines, after notice and opportunity for public hearings, that the discharge of such materials into such area will have an unacceptable adverse effect on municipal water supplies, shellfish beds and fishery areas (including spawning and breeding areas), wildlife, or recreational areas." 33 U.S.C. § 1344(c).

EPA promulgated regulations to govern the section 404(c) process in 1979. *See* 40 C.F.R. §§ 231.1–.8. If a Regional Administrator "has reason to believe . . . that an 'unacceptable adverse effect' could result from the specification or use for specification of a defined area for the disposal of dredged or fill material," she may notify the Corps' District Engineer, site owners, and relevant permit applicants of the intent to prohibit or restrict specification of a disposal site. *Id.* § 231.3(a). The notified parties then have an opportunity to demonstrate that dredge and fill activities will not result in unacceptable adverse effects. *Id.* If the parties cannot make this showing, the Regional Administrator will issue a "proposed determination," *id.*, and institute a public process, *id.* § 231.4. Finally, after the public comment period, the Regional Administrator "shall . . . either withdraw the proposed determination or prepare a recommended determination . . . because the discharge of dredged or fill material at such site would be likely to have an unacceptable adverse effect." *Id.* § 231.5(a). If the Regional Administrator recommends a determination, the EPA Administrator then makes a final determination. *Id.* § 231.6. If, on the other hand, the Regional Administrator decides to withdraw the proposed determination, the EPA Administrator may decline to review the withdrawal, leaving the Regional Administrator's publication of the withdrawal in the *Federal Register* as the final agency action. *Id.* § 231.5(c)(1).

The length and intricacy of the process have real consequences: the Corps cannot issue section 404 permits for the disposal sites under consideration until EPA concludes the section 404(c) process. 33 C.F.R. § 323.6(b); 40 C.F.R. § 231.3(a)(2). Indeed, EPA has only initiated the section 404(c) process a dozen times since enactment of the CWA and has only withdrawn a proposed determination twice.

The Ninth Circuit evaluated Trout Unlimited's (TU) challenge to that second withdrawal in *Pirzadeh*. *Pirzadeh* presents the most recent chapter in the Pebble Mine's dance between agency and court review. Throughout the early 2000s, Pebble Limited Partnership (PLP) began discussions with EPA and the Corps about obtaining permits to mine the Pebble deposit near Bristol Bay, Alaska. *Pirzadeh*, 1 F.4th at 748. In 2010, amid these discussions, nine tribal governments and organizations interested in protecting the vitality of the Bristol Bay ecosystem requested that EPA invoke the section 404(c) process to protect the watershed from mining. *Id.* Following its watershed assessment, the Regional Administrator for Region 10 issued a proposed determination to prohibit mines near the Pebble deposit

> that would result in any of the following conditions: (1) the loss of five miles of streams with documented salmon presence, or nineteen miles of tributaries of those streams; (2) the loss of 1,100 or more acres of wetlands, lakes, and ponds contiguous with salmon streams or tributaries; or (3) streamflow alterations greater than 20% of daily flow in nine miles of salmon streams.

Id. (citing 79 Fed. Reg. 42,314, 42,317 (July 21, 2014)). EPA configured these impacts based on the smallest mine proposed by PLP—the determination would effectively scrap PLP's mining plan. *Id.* at 748–49.

Nevertheless, PLP applied for a section 404 permit in 2017. *Id.* at 749. Following preparation of an environmental impact statement by the Corps, EPA formally withdraw the proposed section 404(c) determination in 2019. *Id.* EPA explained that PLP's permit application differed from the earlier proposed mines upon which the watershed assessment was based, including "plans to place a liner under a disposal facility, to use less waste rock, and to extract minerals using methods other than cyanide leaching." *Id.*

TU challenged the withdrawal in the U.S. District Court for the District of Alaska, alleging that EPA's withdrawal of the proposed determination was arbitrary, capricious, an abuse of discretion, and contrary to law, in violation of the CWA, the EPA's regulations, and the Administrative Procedure Act (APA). *Id.* at 749–50. The district court ultimately dismissed the case, concluding that the withdrawal was unreviewable because neither the CWA nor EPA's implementing regulations provided a meaningful standard upon which to base review. *Id.* at 750. The court also characterized the withdrawal as an unreviewable decision not to take an enforcement action. *Id.*

On appeal, the Ninth Circuit addressed a single question—whether EPA's withdrawal is reviewable under the APA. Because withdrawal of a proposed determination is certainly a final agency action, *id.*, the court's analysis focused on whether withdrawal falls within an exception to APA review—namely, that it constituted an agency action "committed to agency discretion by law," *id.* at 751 (quoting 5 U.S.C. § 701(a)(2)).

The court held that the exception does not apply and that courts can review EPA's withdrawal of a proposed determination. The section 701(a)(2) exception is quite narrow and "applies only 'if no judicially manageable standards are available for judging how and when an agency should exercise its discretion.'" *Id.* (quoting *Heckler v. Chaney*, 470 U.S. 821, 830 (1985)).

In the court's view, the CWA itself contains no such standards. Section 404(c) appears to grant the Administrator broad discretion to initiate public notice and comment and determine whether an unacceptable adverse effect exists. *Id.* at 752. Consequently, the court held that it lacked jurisdiction to review TU's challenge to the extent the challenge was based on provisions of the CWA. *Id.* at 753.

EPA's implementing regulations, however, supply a meaningful legal standard against which to measure agency action. *Id.* The court distilled the Regional Administrator's duties following notice and comment to a simple mandate: "The Regional Administrator 'shall . . . either withdraw the proposed determination or prepare a recommended determination . . . because the discharge of dredged or fill material at such site would be likely to have an unacceptable adverse effect.'" *Id.* at 755 (quoting 40 C.F.R. § 231.5(a)). In other words, the regulations command that the Regional Administrator "either do X or do Y because pollution levels are unacceptable." *Id.* The court also observed that the regulations employ permissive language to govern the early stages of the section 404(c) process but transition to mandatory language for stages following notice and comment. *Id.* at 756. Intuitively, the Regional Administrator's initial unfettered discretion becomes cabined after the public process. *Id.*

The court concluded that section 231.5(a) "allows the Regional Administrator to withdraw a proposed determination *only* if the discharge of materials would be unlikely to have an unacceptable adverse effect." *Id.* at 757. Nevertheless, EPA retains significant discretion of the "ordinary variety" in determining whether adverse effects are likely. *Id.* at 759. The court thus remanded the case for review under the APA but admonished the district court to grant EPA the proper—and admittedly significant—deference that typically accompanies technical agency decisions of this nature. *Id.*

At this stage, *Pirzadeh* represents a victory for TU, tribal governments, and other organizations seeking to capitalize on the administrative process to protect Bristol Bay. The recent success begs the question of what to expect from the section 404(c) process in the future. Although EPA retains significant discretion in responding to requests for proposed determinations, the Ninth Circuit adamantly affirmed court review of determinations that complete the public process. Ultimately, the case may prove to be a test piece for more frequent use of the section 404(c) process to secure robust protections for watersheds.

ARIZONA – MINING

Paul M. Tilley
– Reporter –

Florence Copper Inc. Development Plan Decision Affirmed by State Court of Appeals

The Arizona Court of Appeals affirmed the decision of the Superior Court, Maricopa County, holding that a development agreement between the Town of Florence, Arizona (Town), and Florence Copper Inc. (Florence Copper) provided a vested right to mine. *Town of Florence v. Florence Copper Inc.*, No. 1 CA-CV 19-0504, 2021 WL 1099043, at *1 (Ariz. Ct. App. Mar. 23, 2021, as amended Mar. 24, 2021). The court of appeals also affirmed the sizeable attorney's fee award to Florence Copper. The decision caps a long-running dispute between the Town and Florence Copper regarding the right to operate a mine within the Town limits.

In 2000, a developer, W. Harrison Merrill, purchased land adjacent to the Town with an estimated 1.7 billion pounds of recoverable copper (the "Mining Parcel"). In 2002, the Town approached Merrill about annexing the Mining Parcel and other property where Merrill planned a residential development. In fall 2003, Merrill and the Town entered into a pre-annexation development agreement with a 35-year term (Development Agreement) and a planned unit development agreement (2003 Plan). The Development Agreement and 2003 Plan were approved by the Town Council and the Mining Parcel was annexed by the Town. The Development Agreement granted Merrill the ability to develop the Mining Parcel and prevented the Town from passing zoning ordinances or land use regulations that would limit the ability to develop the Mining Parcel as outlined in the 2003 Plan. *Id.* at *1–2.

The 2003 Plan spelled out land use requirements that aligned with Merrill's plans for the Mining Parcel and his broader property position. The Mining Parcel was zoned light industrial, which prohibited mining, but historical copper mining on the Mining Parcel allowed the non-conforming historical use and preserved mining until the mine was closed. The Development Agreement could only be amended by mutual consent of the parties and any amendment needed to be in writing and recorded in Pinal County within 10 days. The parties amended the Development Agreement twice in accordance with the terms of the agreement. *Id.* at *2.

With the rise of real estate values in the early 2000s, Merrill focused on residential development at the Mining Parcel and requested that the Town allow for an increase in residential density. In 2007, the parties agreed to rezone the Mining Parcel from light industrial to residential and passed a rezoning ordinance codifying the change. Mining at the Mining Parcel was not identified as a non-conforming use and the ordinance did not expressly amend or supersede the Development Agreement. During this time Merrill attempted to sell the Mining Parcel, kept the mine open, and performed required environmental monitoring activities at the Mining Parcel. *Id.*

Merrill ultimately lost the Mining Parcel to foreclosure in the wake of the housing market crash. Florence Copper's parent entity acquired the Mining Parcel in 2009. Shortly thereafter the Town dropped its support for the mine and asserted that its zoning did not allow mining at the Mining Parcel. While Florence Copper did not agree with the Town's position, it still applied for a rezoning and special use permit. But facing mounting opposition from the Town, and other developers, Florence Copper withdrew its application and prepared to mine as allowed under the Development Agreement. The Town responded by filing suit seeking a declaratory judgment that its rezoning of the Mining Parcel in 2007 prohibited mining at the Mining Parcel. *Id.* at *3.

The superior court granted partial summary judgment in favor of Florence Copper holding that the Development Agreement provided a vested right to mine copper at the Mining Parcel as a permissible non-conforming use and that the Town could not move unilaterally through a rezoning ordinance to alter the Development Agreement and hinder the vested rights granted under such an agreement. A six-day bench trial, which included the testimony of 14 witnesses, followed. The trial focused on whether Merrill and the Town mutually agreed to amend the Development Agreement and limit any non-conforming mining rights. The superior court ultimately held that the rezoning activities in 2007 did not eliminate, modify, limit, amend, waive, or abandon the mining rights granted under the Development Agreement. The court also granted Florence Copper declaratory relief and found that it had the judicial remedies of specific performance or contract damages available for breach of contract. A $1.7 million attorney's fee award was also granted to Florence Copper. *Id.* The Town appealed.

On appeal the Town argued that because the Arizona legislature delegated zoning authority to the Town the separation of powers doctrine required the superior court to defer to the Town's decision. *Id.* at *4. The court of appeals rejected the Town's argument stating that a town's zoning decisions are subject to judicial review. *Id.* The court of appeals further noted that the legislature empowered towns to enter into development agreements, such as the one at issue, and that development agreements cannot be amended or terminated without mutual consent of the parties. *Id.* The Town also asserted that the superior court improperly set aside the judgment of the Town's legislative bodies, which are responsible for setting zoning regulations. *Id.* In response to this argument the court of appeals noted that the superior court's ruling merely found that Merrill and the Town voluntarily entered into the Development Agreement. *Id.* The court of appeals pointed to the fact that the Town and Merrill fully embraced the Development Agreement and 2003 Plan for a number of years. *Id.*

The Town also argued in part that it could amend the 2003 Plan through the ordinances and rezoning carried out in 2007, and that Merrill abandoned his vested right to mine by participating in that process. *Id.* at *5. The court of appeals disagreed and found that the 2003 Plan is part of the Development Agreement, and per the terms of that agreement any amendment must be in writing, signed by both parties, and recorded in Pinal County. *Id.* In response to the Town's second argument, the court of appeals pointed to evidence in the record that showed Merrill did not intend to alter or abandon his vested right to mine at the Mining Parcel. *Id.*

CALIFORNIA – OIL & GAS

Tracy K. Hunckler & Megan A. Sammut
– Reporters –

CalGEM Issues Rulemaking to Ban New Well Stimulation Treatment Permits by January 2024

As discussed in Vol. XXXVIII, No. 2 (2021) of this *Newsletter*, Governor Gavin Newsom—in furtherance of his September 23, 2020, executive order—on April 23, 2021, directed the California Department of Conservation's Geologic Energy Management Division (CalGEM) to take regulatory action to halt the issuance of new hydraulic fracturing permits by January 2024. Thereafter, CalGEM began the rulemaking process and on May 21, 2021, publicly released pre-rulemaking draft regulations (Discussion Draft) for public comment. *See* Discussion Draft Rule for Well Stimulation Phase-Out; Notice of Public Comment Period, CalGEM, "Pre-Rulemaking Public Comment Period on the Development of a for Well-Stimulation Treatment Permitting Phase-Out" (May 21, 2021).

The Discussion Draft proposes to add subsection (d) to Cal. Code Regs. tit. 14, § 1780, to include an end date for the issuance of well stimulation treatment permits. The proposed new language provides: "The Division, including the supervisor and district deputies, will not approve applications for permits to conduct well stimulation treatments after January 1, 2024." Proposed Cal. Code Regs. tit. 14, § 1780(d). As written, this end date for permitting would apply not only to hydraulic fracturing permits, but also to permits for all well stimulation treatments, including acid fracturing and acid matrix stimulation. *See* Cal. Code Regs. tit. 14, § 1761(a)(1)(A) (providing examples of "well stimulation treatment"). The rest of section 1780 would remain unchanged, including the specific exclusion of underground injection projects. *See* Cal. Code Regs. tit. 14, § 1780(b).

On June 22, 2021, the Kern County Board of Supervisors (Board) sent a letter to CalGEM staff formally opposing the Discussion Draft. *See* Letter from Kern Cty. Bd. of Supervisors, to CalGEM (June 22, 2021). In its letter, the Board noted that "97% of all well-stimulation permits in California are conducted by Kern County oil companies" and that the Board regulates 80% of the oil and gas produced in California. *Id.* With that background, the Board expressed its opposition to the proposed rule, stating it has "no basis in the established science or real-world implementation" and that state and county regulations have sufficiently protected the public health and safety since 2015. *Id.*

The Board pointed to its 2020/2021 supplemental recirculated environmental impact report, incorporating its 2015 final environmental impact report, in support of its position that there is no scientific evidence backing a ban on well stimulation treatments. *Id.* (citing Kern Cty. Planning & Nat. Res. Dep't, Final Supplemental Recirculated Environmental Impact Report (2020/2021) for Revisions to Title 19 - Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting). It further noted that the proposed regulation would interfere with the rights of mineral owners, would eliminate both jobs and property tax revenue for the county and its residents, and would increase dependence on foreign suppliers that have "lower environmental standards and few of the human rights protections championed by all Californians." *Id.* The Board also included a letter from its outside counsel discussing legal deficiencies with CalGEM's rulemaking as well as the need for a California Environmental Quality Act (CEQA) analysis and a standardized regulatory impact analysis. *Id.*

In a July 2, 2021, letter, the California Independent Petroleum Association (CIPA) also formally opposed the Discussion Draft. *See* Letter from CIPA, to Uduak-Joe Ntuk, State Oil & Gas Supervisor, Cal. Dep't of Conservation (July 2, 2021). Like the Board, CIPA explained that there is no scientific evidence supporting a total ban on well stimulation treatments, pointing to the current state regulations as sufficiently protecting human health and the environment through management and mitigation, as revealed in numerous studies. *Id.*

CIPA additionally stated that the Discussion Draft violates the law, noting that both CalGEM and Governor Newsom have each said they lack the authority to institute such a ban. Moreover, the legislature—who could pass legislation—declined to do so. CIPA also called attention to the need for CEQA and economic analyses, the potential takings claims of lessees and operators, and the loss of jobs and tax revenue that would result from a ban. *Id.*

Finally, CIPA's letter "respectfully reminds CalGEM" of its duty to process permit applications while the pre-rulemaking process is underway. *Id.* CIPA stressed that CalGEM cannot allow a proposed regulation to "result in a de facto termination of permitting for well stimulation treatments." *Id.*

The public comment period on the Discussion Draft closed on July 4, 2021.

CalGEM Denies 21 Hydraulic Fracturing Permits in Kern County, Signaling a De Facto Moratorium Until the New Regulation Takes Effect

Following Governor Gavin Newsom's April 23, 2021, directive to the California Department of Conservation's Geologic Energy Management Division (CalGEM) to take action to halt the issuance of new hydraulic fracturing permits, *see* Vol. XXXVIII, No. 2 (2021) of this *Newsletter*, on July 8, 2021, CalGEM denied 21 hydraulic fracturing permits to Aera Energy LLC (Aera) for operations in Kern County. State Oil and Gas Supervisor Uduak-Joe Ntuk informed Aera of the denials by letter, indicating that he was exercising his discretion "to prevent, as far as possible, damage to life, health, property and natural resources . . . and to protect public health and safety and environmental quality, including [the] reduction and mitigation of greenhouse gas emissions . . . ." John Cox, "State Exercises Discretion to Deny Kern Fracking Permits Ahead of Formal Ban," *Bakersfield Californian* (July 9, 2021) (alteration in original) (internal quotation marks omitted). In an email to the *Bakersfield Californian*, Ntuk cited to "the effects of the climate emergency" and wrote that "the risks to everyday Californians are too high to approve these permits." *Id.*

This exercise of discretion marks a shift away from previous permit denials based on technical reviews by federal scientists and state engineers and suggests that there now is a de facto moratorium on the issuance of hydraulic fracturing permits in the state. Governor Newsom's office provided a statement that

> [t]he Governor applauds [the] action by the State Oil and Gas Supervisor to use his discretion under statute to deny 21 pending fracking permits, which will protect public health and safety and environmental quality and mitigate greenhouse gas emissions. This is one of many actions the Administration is taking to reduce and mitigate greenhouse gas emissions and respond to the climate emergency.

Id.

Aera issued a statement following the denials, saying the decision was "based solely on politics rather than sound data or science," and noting that "some of the brightest minds in the world have deemed that hydraulic fracturing is safe and that it does not release hazardous chemicals to surface waters or cause groundwater contamination." Bus. J. Staff, "State Denies Valley Fracking Permits, Citing Health and Climate Concerns," *Business Journal* (July 9, 2021). Lawmakers representing Kern County were also disappointed with the decision, saying the Governor should "protect quality careers and vital tax funding while ensuring Californians have access to affordable and reliable energy," while environmental groups were dissatisfied that the Governor did not go far enough, saying the agency should "deny all new oil and gas permits immediately." Assoc. Press, "California Oil Regulators Deny New Fracking Permits," *Mercury News* (July 12, 2021).

On July 16, 2021, Aera filed a notice of appeal to the California Department of Conservation, asking the Director to set aside CalGEM's orders and approve the 21 permit applications. *See* Notice of Appeal of July 8, 2021 Orders Denying Well Stimulation Treatment Permit Applications, *In re Aera Energy LLC* (July 16, 2021). The appeal argues CalGEM's orders should be set aside because they (1) are arbitrary, capricious, and not supported by evidence; (2) violate CalGEM's statutory duty to encourage the development of oil and gas resources and to permit practices known to increase hydrocarbon recovery; (3) are unlawful because the permits were deemed approved under the Permit Streamlining Act due to CalGEM's delays; (4) constitute a taking; (5) violate Aera's due process rights; (6) violate Aera's right to equal protection; (7) violate the California Administrative Procedure Act; and (8) violate the separation of powers doctrine. Importantly, Aera asserts that CalGEM technical staff had already recommended approval of the permits and several other agencies had also found no technical reason to deny them.

Culver City Counsel Passes Ordinance to End Drilling by July 2026

On June 17, 2021, the Culver City Council held a public hearing on the introduction of an ordinance to approve an amendment to the Zoning Code that would terminate nonconforming oil and gas uses by July 28, 2026, including operations in the Culver City portion of the Inglewood Oil Field (IOF). *See* Culver City, "Inglewood Oil Field," https://www.culvercity.org/City-Hall/Get-Involved/Inglewood-Oil-Field. The ordinance passed by a 4-1 vote. *See* "City Council Votes to End Oil Drilling in Culver City by 2026," *Culver City Observer* (June 17, 2021). A PDF of the ordinance is available at https://culver-city.legistar.com/View.ashx?M=F&ID=9472200&GUID=52641F96-2690-43E2-9569-8B63C9B6B533.

This is the last step in Culver City's efforts to phase out fossil fuel extraction within its city limits. As set forth in the proposed ordinance, the process began with the City Council's request at its June 20, 2018, special meeting that staff study and outline options for the possible amortization and termination of nonconforming oil and gas activities in the city's portion of the IOF. In May 2019, the City Council authorized a consultant to prepare a study of the amortization of the original capital investment in the production facilities. The following year, the City Council Oil Drilling Subcommittee held a public community meeting to present the study. After further study, including stakeholder and public input, the subcommittee and staff provided recommendations to the City Council to begin the formal process to terminate and phase out oil and gas activities in the city limits. Thereafter, at its October 26, 2020, meeting, the City Council adopted Resolution No. 2020-R100. The resolution stated the City's intent to evaluate the establishment of a five-year phaseout period for the amortization of nonconforming oil and gas uses in the city.

The June 17, 2021, hearing introduced the ordinance to "approve a City-Initiated Zoning Code Amendment to Chapter 17.610 (Nonconforming Uses, Structures and Parcels), Section 17.610.010.D (Nonconforming Oil Use), to terminate and phase-out over a five-year period (by July 28, 2026) the closure and removal of nonconforming oil and gas activities within Culver City . . . ." Culver City, "Inglewood Oil Field," *supra*. By voting to approve the ordinance, the City Council approved the five-year phaseout of drilling, including prohibiting new wells and requiring that all existing wells be properly capped and the sites remediated. The ordinance also directs staff to "refine preliminary implementation procedures and 'just transition' strategies" for workers in the IOF.

COLORADO – OIL & GAS

Sarah Sorum & Kate Mailliard
– Reporters –

Court of Appeals Adopts "Commercial Discovery" Rule

In May 2021, the Colorado Court of Appeals formally adopted the "commercial discovery" rule, which provides that the discovery of oil or gas is sufficient to satisfy the habendum clause in a lease; therefore, production or extraction of oil or gas is not required to prevent the lease from terminating. *Bd. of Cty. Comm'rs of Boulder Cty. v. Crestone Peak Res. Operating LLC*, 2021 COA 67.

In *Crestone Peak*, Boulder County sued Crestone Peak Resources Operating LLC (Crestone), alleging that wells subject to two leases covering the County's mineral interest had stopped producing, and thus the leases had terminated. Crestone's predecessor-in-interest, Encana Oil & Gas (USA), Inc., had been selling and delivering gas to Anadarko Petroleum Corporation (Anadarko) through a pipeline connected to the relevant wells. However, in 2014, Anadarko closed the pipeline for about four months due to a maintenance issue. In February 2019, the County sued Crestone for failure to surrender the leases under the theory that the leases had terminated during the extraction pause in 2014. The district court disagreed and held that the temporary extraction pause did not constitute a cessation in production. The court of appeals affirmed the district court's decision.

Both of the leases at issue contained habendum clauses as well as cessation of production clauses and clauses for shut-in royalties. The County argued that "production" means extraction of hydrocarbons from the ground. *Id.* ¶ 14. The court disagreed and pointed to a 1992 decision that held that production under a habendum clause "is satisfied by discovery in commercial quantities." *Id.* ¶ 19 (quoting *Davis v. Cramer*, 837 P.2d 218, 222 (Colo. App. 1992)). The County argued that *Davis* did not apply because the lease at issue there did not contain a cessation clause and because the dispute surrounded the primary term of the lease rather than the secondary term. *Id.* ¶¶ 20–21. The court found that these distinctions made no difference or were irrelevant. *Id.* Thus, the court adopted the commercial discovery rule and supported this decision by pointing to the specific terms of the leases at issue. The court said that "[m]ost important to our conclusion is the fact that Boulder's position (that production includes extraction) renders the leases' clauses for shut-in royalties inoperative." *Id.* ¶ 26. The court held that the leases should be interpreted such that effect is given to all of their contractual provisions, and rendering the shut-in royalty clauses inoperative is avoided by applying the commercial discovery rule. *Id.* ¶¶ 26–29.

The commercial discovery rule "accommodates the economic realities of the oil and gas industry," *id.* ¶ 32, and protects both lessees and lessors, *id.* ¶ 34. The rule "protects lessees who have invested millions of dollars . . . from losing that investment due to temporary extraction pauses," while also not "depriv[ing] lessors of their rights to royalty-generating activity." *Id.* Lessor interests, the court noted, "are already protected by the common law duty to market." *Id.*

The County has filed a petition for writ of certiorari with the Colorado Supreme Court.

Court of Appeals Holds Courts, Not COGCC, Should Settle Lease Interpretation Disputes

In an unpublished opinion, a three-judge Colorado Court of Appeals panel held that courts, not the Colorado Oil and Gas Conservation Commission (COGCC), should settle royalty payment disputes involving lease interpretation. *Antero Res. Corp. v. Airport Land Partners Ltd.*, No. 19CA1799, 2021 WL 2365973 (Colo. App. June 3, 2021) (unpublished).

The June 2021 ruling involved the deduction of certain post-production costs that reduced royalty payments to various mineral owners. At issue were actions brought in 2016 and 2017 by mineral owners in Garfield County against Antero Resources Corporation (Antero) and Ursa Operating Company, LLC (Ursa). Ursa, which had purchased Antero's oil and gas holdings, was later removed as a party to the case after filing for bankruptcy. The two companies sought to dismiss the mineral owners' suits, arguing that the mineral owners failed to exhaust administrative remedies by not taking the matters to the COGCC. However, the COGCC told the mineral owners that it lacked jurisdiction over the cases because they involved bona fide disputes over lease interpretation.

The Denver District Court agreed with Antero and Ursa that the COGCC had jurisdiction over the now-consolidated cases, finding that the contractual disputes were merely factual disagreements over royalties owed and that legal interpretation of the leases was not required. The appeals court disagreed and sent the case back to the district court for resolution on the merits.

The Colorado Oil and Gas Conservation Act gives the COGCC jurisdiction to determine (1) the "date on which payment of proceeds is due a payee"; (2) the "existence or nonexistence of an occurrence . . . which would justifiably cause a delay in payment"; and (3) the "amount of the proceeds plus interest, if any, due a payee by a payer." Colo. Rev. Stat. § 34-60-118.5(5). However, when a bona fide contractual dispute exists, the COGCC "does not have jurisdiction to interpret any royalty agreement to determine the propriety of disputed post-production deductions." *Grynberg v. COGCC*, 7 P.3d 1060, 1063 (Colo. App. 1999).

COGCC Issues Guidance on New Rules

The Colorado Oil and Gas Conservation Commission (COGCC) has been developing new rules since the passing of Senate Bill 19-181, which required the COGCC to change its mission from "fostering" oil and gas development to "regulating" oil and gas development in a manner that protects public health, safety, welfare, the environment, and wildlife resources. As the rules take effect, the COGCC has begun issuing guidance and revising previously issued guidance to aid operators in interpreting and following the new rules. Among the new documents is guidance on Rule 903, which requires operators to notify mineral owners of the volume of oil and gas that is vented, flared, or used on-lease. *See* COGCC Operator Guidance, "Rule 903.d.(4).B - Reporting Volume of Natural Gas that Is Vented, Flared, or Used on Lease to Mineral Owners" (Feb. 11, 2021). The document states that one goal of Rule 903 is to "incentivize operators to capture more natural gas." *Id.* The remaining operator guidance documents can be found at https://cogcc.state.co.us/reg.html#/opguidance_mc.

COGCC Holds Hearings on Changes to Financial Assurances

The Colorado Oil and Gas Conservation Commission (COGCC) has been holding weekly hearings with industry and other groups regarding financial assurances, one of the three remaining mandated rulemakings from Senate Bill 19-181 (SB 19-181). *See* Press Release, COGCC, "Colorado Oil & Gas Conservation Commission Discusses Financial Assurance" (Mar. 30, 2021). However, in mid-July, the COGCC voted to delay public hearings on a new set of financial assurance rules until January 2022. *See* Chase Woodruff, "Colorado Oil and Gas Commission Delays New Bonding, Orphaned-Well Rules Until 2022," *Colo. Newsline* (July 15, 2021).

Currently, an operator must provide financial assurance to the COGCC in order to conduct oil and gas operations in Colorado, but SB 19-181 called for broad changes to financial assurances. The Oil and Gas Conservation Act, as revised by SB 19-181, now states:

> The [COGCC] shall require every operator to provide assurance that it is financially capable of fulfilling every obligation imposed by this article 60 as specified in rules adopted on or after April 16, 2019. The rulemaking must consider: Increasing financial assurance for inactive wells and for wells transferred to a new owner; requiring a financial assurance account, which must remain tied to the well in the event of a transfer of ownership, to be fully funded in the initial years of operation for each new well to cover future costs to plug, reclaim, and remediate the well; and creating a pooled fund to address orphaned wells for which no owner, operator, or responsible party is capable of covering the costs of plugging, reclamation, and remediation.

Colo. Rev. Stat. § 34-60-106(13).

LOUISIANA – OIL & GAS

Kathryn Gonski & Court VanTassell
– Reporters –

Louisiana Supreme Court Limits Damages Available to Landowners in Legacy Litigation

On June 30, 2021, the Louisiana Supreme Court issued an opinion that reversed the "palpable error" of the court's decision eight years prior and redefined the nature of available damages and the "actual, statutorily permitted role of the jury in Act 312 remediation lawsuits." *State v. La. Land & Expl. Co.* (*LL&E II*), 2020-00685 (La. 6/30/2021); 2021 WL 2678913, at *5.

In 2013, the Louisiana Supreme Court decided *State v. Louisiana Land & Exploration Co.* (*LL&E I*), 2012-0884 (La. 1/30/13); 110 So. 3d 1038. In *LL&E I*, the court held that, even without an express contractual provision, defendants who operated unreasonably had an *implied* obligation under the Mineral Code to restore property above and beyond regulatory environmental standards. *LL&E I* further determined that these "excess remediation damages" were awards landowners could keep for themselves under Act 312.

After *LL&E I* was decided, the case went to trial. The jury (1) awarded $3.5 million to remediate the land in compliance with regulatory standards, (2) awarded $1.5 million on the landowners' strict liability claim, and (3) denied all other causes of action. On appeal, the Louisiana Court of Appeal for the Third Circuit remanded the case for a new trial, finding that the verdict was inconsistent in awarding damages for remediation and strict liability, but rejecting the breach of contract claims.

The supreme court disagreed with the Third Circuit remand and held that the verdict was consistent "when viewed in light of the improper jury instructions given to them." *LL&E II*, 2021 WL 2678913, at *5. The court recognized the dilemma in that the jury was essentially told to find the defendant liable for remediation damages and find the amount of damages necessary to remediate the land, and then they were instructed on the various private causes of action. "This was all done in light of [*LL&E I*], which we now see with clarity, was made in error." *Id.*

The "two critical errors" that the court identified in the "misguided decision" of *LL&E I* were the holdings that (1) juries could decide the amount of damages necessary to remediate land to regulatory standards, and (2) excess remediation damages could be available in cases without an express contractual restoration provision. *Id.* Referring to the "clear and unambiguous" language of Act 312, the court in *LL&E II* instead reached the following conclusions:

> (1) outside of an express contractual provision, Act 312 does not allow for remediation damages in excess of those required to fund the court adopted remediation plan; (2) the plan is left to the sole judgment of the trial court itself, not the jury; and therefore, (3) Act 312 provides no intent for the jury to decide the amount of remediation damages that meet Act 312 compliance. Act 312 only allows the jury to award excess remediation damages when an express contractual provision providing for such an award exists. Outside of any express contractual provision being present, it is error to have the jury consider any damages related to Act 312 remediation of the property. The jury's sole role is to consider liability and damages for private causes of action, as well as for contractual causes of action where an express provision allows for remediation and damages in excess of governmental standards.

Id. at *7. The court reversed and vacated the judgment for remediation damages, "finding there is not, and never was, statutory support for the award. Rather, specific performance of remediation, i.e. the cost of actual clean-up, is appropriate." *Id.* at *8.

At the time of this report applications for rehearing remain pending, but this landmark decision is poised to have sweeping implications for Louisiana legacy lawsuits.

Louisiana First Circuit Reaffirms Prescription and Subsequent Purchaser Principles

In *Lexington Land Development, L.L.C. v. Chevron Pipeline Co.*, 2020-0622 (La. App. 1 Cir. 5/25/21); 2021 WL 2102932, the Louisiana Court of Appeal for the First Circuit reaffirmed well-settled principles regarding prescription and the subsequent purchaser doctrine in Louisiana legacy cases.

Lexington Land Development, L.L.C. (Lexington Land) filed a legacy lawsuit against Chevron U.S.A., Inc. (Chevron) for alleged property damage arising out of oil and gas operations that occurred between 1959 and 1991. Lexington Land purchased the property in 2005 but did not obtain an assignment of the personal right to sue for pre-purchase property damage from the prior owners. Also, the act of sale included several disclaimers regarding the environmental condition of the property related to oil and gas operations, and the purchase price took these disclaimers into consideration. Furthermore, Lexington Land's lenders required environmental assessments of the property, which Lexington Land received in 2005, and these assessments discussed the environmental condition of the property from historical oil and gas operations, included aerial photos showing saltwater scarring and stressed vegetation, and included compliance orders issued to a separate operator requiring the closure of certain pits on the property. Although Lexington Land received these environmental assessments in 2005, it did not file suit until 2007. *Id.* at *1–2.

The trial court made two rulings that resulted in the dismissal of all of Lexington Land's claims. First, it granted Chevron's motion for partial summary judgment dismissing all claims for pre-2005 damage to the property under the subsequent purchaser doctrine. In an attempt to circumvent this ruling, Lexington Land obtained from the prior landowners an assignment of the right to sue for pre-purchase damage. Lexington Land then filed a supplemental and amending lawsuit asserting its assigned claims against Chevron under both tort and contract theories. Chevron responded with an exception of prescription, arguing that all amended claims were prescribed (time-barred) under a one-year prescriptive period because Chevron's operations ceased in 1991, and Lexington Land had actual knowledge of alleged damage to the property by at least 2007 when it originally filed suit. The trial court granted Chevron's exception, finding that the act of sale disclaimers and the environmental assessments were sufficient to put Lexington Land on notice of potential damage to the property in 2005, and thus its amended claims against Chevron were all prescribed. *Id.* at *3–4.

The First Circuit affirmed. On prescription, the First Circuit held that Lexington Land's claims were prescribed because, like the dying sugarcane crops that were sufficient to provide the landowners with constructive knowledge of their claims in *Marin v. Exxon Mobil Corp.*, 2009-2368 (La. 10/19/10); 48 So. 3d 234, the environmental assessments, coupled with the disclaimers in the act of sale, were sufficient to provide Lexington Land with constructive knowledge of its claims more than one year before suit was filed. *Lexington Land*, 2021 WL 2102932, at *12–13. As to the post-suit assignment of claims, the First Circuit found that, regardless of whether Lexington Land's assigned contract claims were prescribed, those claims should still be dismissed because the surface and mineral leases under which Chevron operated expired before Lexington Land obtained its assignment from the prior owners. *Id.* at *13–14. Finally, as to the subsequent-purchaser issue, the First Circuit reaffirmed the "firmly established" principle that the right to sue for pre-purchase property damage is a personal right that does not transfer to a subsequent purchaser absent an express assignment or subrogation from the prior owner. *Id.* at *16. Because Lexington Land had no such assignment when it originally filed suit, its claims for pre-acquisition damages were barred under the subsequent purchaser doctrine. *Id.*

Louisiana Federal District Court Addresses Notice Requirements Under La. Stat. Ann. §§ 30:103.1–.2

La. Stat. Ann. § 30:103.1 sets forth reporting requirements that an operator must provide to owners of unleased oil and gas interests within a compulsory drilling unit, and La. Stat. Ann. § 30:103.2 imposes a penalty for the operator's failure to comply with these requirements. In *Limekiln Development, Inc. v. XTO Energy Inc.*, No. 1:20-cv-00145, 2021 WL 956079 (W.D. La. Feb. 5, 2021), *adopted by* 2021 WL 950909 (W.D. La. Mar. 12, 2021), the U.S. District Court for the Western District of Louisiana addressed whether the unleased owner's notices to the operator were sufficient to trigger the reporting requirements of section 30:103.1, and thus, the potential penalty of section 30:103.2, in the context of the defendant's motion to dismiss under Fed. R. Civ. P. 12(b)(6).

The defendant argued that the unleased owner's notices were insufficient because (1) the first notice, requesting reports under section 30:103.1, failed to identify the specific land the party claimed to own; and (2) the second notice, alleging that the reports the defendant subsequently sent were deficient under section 30:103.2, merely stated that the defendant failed to comply with the statute without explaining why the reports were allegedly insufficient. The court rejected both arguments and denied the defendant's motion.

The court noted that under the plain language of section 30:103.1, the statute only requires that requests be "in writing, by certified mail addressed to the operator or producer" and "contain the unleased interest owner's name and address." *Limekiln*, 2021 WL 956079, at *3 (quoting La. Stat. Ann. § 30:103.1(C)). The unleased owner's first notice not only included this information, it also identified the unit in which the interest was located. As to section 30:103.2, the statute provides that the notice of default "must be 'written notice by certified mail' which 'call[s] attention to [the operator's] failure to comply with the provisions of [section] 30:103.1.'" *Id.* at *8 (first and second alterations in original) (quoting La. Stat. Ann. § 30:103.2). The court held that the unleased owner was not required to provide specific details as to the alleged deficient reporting, finding its notice sufficient because it "specifically notified [the operator] that it failed to send [the unleased owner] 'the necessary, sworn, detailed, and itemized statements as required by [section] 30:103.1.'" *Id.* at *9. The court therefore concluded that, at this stage of the proceeding, the unleased owner stated a plausible claim for the forfeiture penalty under section 30:103.2. *Id.*

MINNESOTA – MINING

Aleava R. Sayre & Gregory A. Fontaine
– Reporters –

Litigation Continues over Minntac Mine Water Permits

The Minnesota Court of Appeals has released another opinion in the long-running legal battle over permits and pollution remedies for the Minntac taconite mining operation in Minnesota. *See In re Reissuance of NPDES/SDS Permit to U.S. Steel Corp. (Minntac III)*, Nos. A18-2094, A18-2095, A18-2159, A18-2163, 2021 WL 2645505 (Minn. Ct. App. June 28, 2021). U.S. Steel Corporation (U.S. Steel) owns and operates Minntac, which includes an iron ore mine, a taconite processing plant, and a large tailings basin. At the center of the current dispute are the renewed water permit issued by the Minnesota Pollution Control Agency (MPCA) in 2018, applicable surface water and groundwater water quality standards, and permit limits and treatment requirements imposed by MPCA. The permit is a combined National Pollutant Discharge Elimination System (NPDES) and State Disposal System (SDS) permit issued by MPCA pursuant to its delegated authority under the federal Clean Water Act (CWA) and Minnesota water laws. It regulates discharges to both surface waters (NPDES) and groundwater (SDS).

The NPDES/SDS permit establishes, among other things, numeric effluent limits for sulfate and total dissolved solids (TDS) that must be achieved by 2025. U.S. Steel sought a 20-year variance from these permit limits, arguing that it could meet these water quality and timing requirements only by installing a reverse osmosis treatment plant to clean up polluted tailings basin water. Because the cost of the treatment plant would exceed $130 million in capital costs and nearly $30 million in annual operating costs, U.S. Steel claimed that these requirements would make the operations economically infeasible. MPCA denied the variance request.

Both U.S. Steel and the parties opposing the permit renewal appealed to the Minnesota Court of Appeals with a petition for writ of certiorari (the routine process for challenging permit decisions in Minnesota). As discussed in Vol. XXXVII, No. 2 (2020) of this *Newsletter*, the court of appeals upheld certain portions of MPCA's decision but reversed others. *In re Reissuance of NPDES/SDS Permit to U.S. Steel Corp.* (*Minntac I*), 937 N.W.2d 770 (Minn. Ct. App. 2019), *rev'd*, 954 N.W.2d 572 (Minn. 2021) (*Minntac II*). The Minnesota Supreme Court then granted review with respect to two questions: (1) whether the CWA governs pollutant discharges to groundwater and (2) whether the state's Class I water quality standards apply to groundwater.

Before the Minnesota Supreme Court issued its decision, the U.S. Supreme Court addressed the first question in *County of Maui v. Hawaii Wildlife Fund*, 140 S. Ct. 1462 (2020). In the wake of that U.S. Supreme Court precedent, the Minnesota Supreme Court's *Minntac II* opinion directed that the *Maui* issue be returned to MPCA for consideration, reversed the court of appeals' decision on application of the Class I water standards in *Minntac I*, and remanded the case to the court of appeals to address other issues unresolved in its earlier opinion.

In its latest ruling, issued on June 28, 2021, the court of appeals again partially upheld and partially reversed MPCA's 2018 permit decision. The court affirmed MPCA's denial of U.S. Steel's request for a contested case hearing on the permit application. *Minntac III*, 2021 WL 2645505. Applying the substantial evidence test recently reiterated in *In re NorthMet Project*, 959 N.W.2d 731 (Minn. 2021), *see* Vol. XXXVIII, No. 2 (2021) of this *Newsletter*, the court of appeals determined that MPCA met this standard in the Minntac permitting proceedings. Specifically, the court held that MPCA sufficiently considered U.S. Steel's arguments concerning certain permit limits and adequately explained its decision to deny the hearing request, and that the administrative record supported this explanation. *Minntac III*, 2021 WL 2645505, at *3–4.

The court of appeals also upheld MPCA's denial of U.S. Steel's request for a variance from application of the state's groundwater water quality standards and the related sulfate and TDS permit limits. The court characterized U.S. Steel's arguments in favor of the variance as falling into essentially three categories: (1) "economic hardship" or "economic infeasibility" due to treatment costs, (2) technical unreasonableness and impracticality of compliance because of natural background levels of certain potential contaminants, and (3) administrative inconsistency grounded in the agency's issuance of a variance to a different company in an unrelated matter. The court applied deference principles and the conventional tests under the Minnesota Administrative Procedure Act, including the substantial evidence and arbitrary and capricious analyses, to each of U.S. Steel's arguments. *Id.* at *5 (citing Minn. Stat. § 14.69). With respect to each argument, the court concluded that MPCA's determinations rejecting the company's position were adequate in light of the administrative record for the case. *Id.* at *5–6.

The economic impact issues as presented in *Minntac III*'s analysis of U.S. Steel's variance request appear to fall into two separate economic and cost arguments. First, the company contended compliance with the permit limits would be "economically infeasible" because of the cost of the reverse osmosis treatment technology. U.S. Steel based this argument in Minn. R. 7000.7000, subp. 2(E), which allows MPCA to grant a variance based on proof of "economic burden." Second, U.S. Steel appears to have argued that, even if compliance was not economically infeasible, the permit limits were still "unreasonable" given the substantial economic impacts both to the company and third parties. The company advocated for application of a balancing test to consider both its evidence of the negative economic impacts and the environmental need for the permit limits in question. This argument was tethered to the groundwater rules in Minn. R. 7060.0900, which authorizes a variance where strict compliance would cause "undue hardship" or would be "unreasonable, impractical, or not feasible under the circumstances." *Minntac III*, 2021 WL 2645505, at *5.

The *Minntac III* opinion did not parse through the different variance criteria in the applicable rules in detail. Rather, the court generally deferred to MPCA's decision as reasonably explained and supported by the record without close scrutiny. *Id.* at *6.

Finally, the court of appeals explained that its ruling in *Minntac I* with regard to water quality based effluent limits (WQBELs) had not been appealed to the state supreme court. Accordingly, the court reaffirmed its prior decision that MPCA's determination that WQBELs were not required for certain surface water discharges was not supported by substantial evidence. The court therefore reversed MPCA's decision granting the renewed permit to U.S. Steel and remanded the matter to the agency for further analysis and findings relating to WQBEL issues and for evaluation of the functional equivalence analysis required by the U.S. Supreme Court's *Maui* opinion. *Id.* at *7.

In response to the court's opinion, U.S. Steel, in late July, filed a petition for certiorari with the Minnesota Supreme Court seeking further review of the denial of its variance request. As of the date of this report, the Minnesota Supreme Court has yet to act on that petition.

Litigation Continues over Minnesota Nonferrous Mining Rules

The Minnesota Court of Appeals has accepted in part an appeal filed by Twin Metals Minnesota LLC (Twin Metals) from an order of the district court in Ramsey County, Minnesota, denying the company's motion to dismiss a case filed by an environmental group under the Minnesota Environmental Rights Act (MERA), Minn. Stat. §§ 116B.01–.13. *See Northeastern Minnesotans for Wilderness v. Minn. Dep't of Nat. Res.*, No. A21-0857 (Minn. Ct. App. Aug. 3, 2021). The court of appeals issued an earlier order denying Twin Metals' petition for discretionary review of the district court's May 12, 2021, order, primarily on the ground that interlocutory appeals are generally disfavored. *See Northeastern Minnesotans v. Minn. Dep't of Nat. Res.*, No. A21-0743 (Minn. Ct. App. July 6, 2021). The appeal arises from a lawsuit filed by Northeastern Minnesotans for Wilderness (NMW) against the Minnesota Department of Natural Resources (DNR) challenging the state's nonferrous mining rules, Minn. R. ch. 6132. NMW seeks to require DNR to ban the siting of any nonferrous mining facilities and any related activities in the Rainy River watershed in northern Minnesota, where the Boundary Waters Canoe Area Wilderness (BWCAW) is located.

The Minnesota nonferrous mining rules prohibit mining within the BWCAW and certain buffer areas around the wilderness (beyond those buffers established under federal law) but not the entire Rainy River watershed, which encompasses approximately 3,000 square miles. Twin Metals has proposed construction of an underground mine within the Rainy River watershed, but outside of the BWCAW and its buffer areas. The U.S. Bureau of Land Management, the Minnesota DNR, and other responsible agencies are evaluating the company's mine plan of operations and other regulatory filings as part of their environmental review of the project.

MERA provides a cause of action to citizens of Minnesota for declaratory or equitable relief against the State of Minnesota or its agencies with respect to any "environmental quality standard, limitation, rule, order, license, stipulation agreement, or permit . . . *for which the applicable statutory appeal period has elapsed*." Minn. Stat. § 116B.10, subd. 1 (emphasis added). To maintain such a MERA claim, the plaintiff has the burden of proving the challenged state actions—in this case DNR's nonferrous rules—are "inadequate to protect . . . natural resources located within the state from pollution, impairment, or destruction." *Id.* § 116B.10, subd. 2. If the plaintiff makes a prima facie showing of the alleged inadequacy, the matter can be remitted to the state agency for administrative proceedings to consider and make findings on the challenged actions. *Id.* § 116B.10, subd. 3.

NMW filed its MERA claim against DNR in June 2020 in the Ramsey County District Court. Twin Metals intervened three months later, and then in November 2020, NMW and DNR filed a proposed stipulation with the district court requiring a remittitur to DNR. Twin Metals declined to join the stipulation.

In the proposed stipulation, DNR agreed to proceed directly to the remittitur proceeding before the agency under MERA without requiring NMW to make the required prima facie showing in court. However, in the stipulation DNR did not commit to any specific substantive outcome with respect to its review of the nonferrous mining rules and it provided assurances that it would continue its independent environmental review of the mining project proposed by Twin Metals.

Twin Metals elected to challenge the stipulation by moving to dismiss NMW's lawsuit on various grounds, including NMW's alleged lack of standing and failure to comply with MERA's requirement concerning expiration of an applicable statutory appeal period. The district court, in an order dated May 12, 2021, agreed that resolution of the motion to dismiss was a prerequisite to considering the proposed stipulation but denied the motion on the merits. Order & Memorandum at 3–8, *Northeastern Minnesotans v. Minn. Dep't of Nat. Res.*, No. 62-CV-20-3838 (Minn. Dist. Ct., Ramsey Cty., May 12, 2021). The court found NMW has standing to assert its MERA claim and rejected the other procedural and substantive arguments asserted by the company. The court then approved the proposed stipulation and remanded the matter to DNR for administrative proceedings consistent with the stipulation and the requirements of Minn. Stat. § 116B.10.

Twin Metals appealed the district court's denial of the motion to dismiss. After requiring submittals as to whether the appeal was premature, the Minnesota Court of Appeals issued an order accepting a portion of Twin Metals' appeal. Order at 2, *Northeastern Minnesotans*, No. A21-0857. The court of appeals determined that, to the extent that Twin Metals' motion to dismiss was based on NMW's alleged lack of standing, the district court's order denying the motion was immediately appealable. The court of appeals based its decision on Minnesota Supreme Court precedent providing that an order denying a motion to dismiss for lack of personal or subject matter jurisdiction is immediately appealable. The court further found that Twin Metals' standing argument was properly characterized as a motion to dismiss for lack of jurisdiction.

The court of appeals, however, declined to accept an immediate appeal of the other issue raised by Twin Metals, namely the company's argument that NMW had failed to meet the MERA requirement that there be an elapsed statutory appeal period. *Id.* at 3–4. The court of appeals concluded that this MERA requirement was not a jurisdictional limitation on the district court's authority. Accordingly, the court of appeals found that the district court's denial of Twin Metals' motion to dismiss on this MERA ground was not immediately appealable.

If Twin Metals prevails on its appeal, then presumably the underlying litigation would be dismissed for lack of jurisdiction and the stipulation approved by the district court would be invalidated. If the case proceeds, however, DNR will need to decide whether and how to modify its nonferrous permit to mine rules, which would trigger a rulemaking process that includes administrative evidentiary hearings under Minnesota law. Presumably, any outstanding legal challenges along with those that arise from any rulemaking, or lack thereof, will also be subject to judicial proceedings.

Editor's Note: The reporters represent companies discussed in this report that are involved in various projects discussed here.

Appeals Court Remands PolyMet Mining Project Air Permit Decision to Agency

As reported in Vol. XXXVIII, No. 2 (2021) of this *Newsletter*, the Minnesota Supreme Court earlier this year reversed the Minnesota Court of Appeals 2020 decision that the Minnesota Pollution Control Agency (MPCA), in issuing a synthetic minor air permit to Poly Met Mining, Inc. (PolyMet) for its planned copper-nickel mine, violated federal law by not investigating alleged sham permitting allegations. *See In re Issuance of Air Emissions Permit No. 13700345-101 for PolyMet Mining, Inc.*, 955 N.W.2d 258 (Minn. 2021). The Minnesota Supreme Court returned the matter to the court of appeals to address certain other arguments advanced by project opponents that were not grounded in the federal requirements on which the court of appeals had erroneously relied. *Id.* at 269.

In July, the court of appeals issued its latest opinion and remanded the permit back to MPCA for further consideration under state law of two questions raised by the project opponents: (1) whether PolyMet will comply with all the conditions in the air permit, and (2) whether the company failed to disclose all relevant facts or knowingly submitted false or misleading information to MPCA. *In re PolyMet Mining, Inc.*, Nos. A19-0115, A19-0134, 2021 WL 3027199, at *8 (Minn. Ct. App. July 19, 2021). The court of appeals thus declined to resolve these issues in favor of the agency and company, but also specifically decided not to reverse MPCA's decision granting the permit. Rather, the court concluded that the agency had not adequately explained the basis for its conclusions concerning the two questions and remanded these issues to the agency for further explanation. *Id.* at *9. At the time of this report, the parties have not petitioned to the Minnesota Supreme Court for review of this decision and, in the absence of such review, MPCA is expected to proceed with its remand duties.

Editor's Note: The reporters represent companies discussed in this report that are involved in various projects discussed here.

NORTH DAKOTA – OIL & GAS

Ken G. Hedge
– Reporter –

North Dakota Adopts "At the Well" Valuation of Oil Royalty

In *Blasi v. Bruin E&P Partners, LLC*, 2021 ND 86, 959 N.W.2d 872, the North Dakota Supreme Court found that an oil royalty provision commonly found in North Dakota oil and gas leases requires royalty payments to be based on the value of oil "at the well." *Id.* ¶ 1. There, the plaintiffs (Blasi) sued various oil and gas operators in separate putative class actions in the U.S. District Court for the District of North Dakota, alleging the operators underpaid royalties owed under various oil and gas leases. *Id.* ¶ 2. In response to the defendants' motion to dismiss the actions as a matter of law, the federal court certified to the North Dakota Supreme Court the question of whether the oil royalty provision at issue "is interpreted to mean the royalty is based on the value of the oil 'at the well.'" *Id.* ¶ 4. Specifically, the oil royalty provision obligates the lessee to "deliver to the credit of the Lessor, free of cost, in the pipeline to which Lessee may connect wells on said land, the equal [fractional] part of all oil produced and saved from the leased premises." *Id.* ¶ 2 (alteration in original). Blasi claimed that the royalty was to be paid "free of costs," and that the defendants were improperly deducting gathering, transportation, and other costs from the marketable price. *Id.* ¶ 3.

When "crude oil travels through the stream of production, its value increases as costs are incurred to bring it to market." *Id.* ¶ 5. The North Dakota Supreme Court was asked to determine whether the royalty clause at issue "establishes a royalty valuation point at the well or whether the valuation point is at some other place downstream." *Id.* The court noted that it has previously adopted the work-back method—which accounts for costs in determining value of oil or gas at a given point in the stream of production—with respect to a royalty valuation point that was "at the well," although the court noted that parties are free to contractually set a valuation point elsewhere in the stream of production. *Id.* (citing *Bice v. Petro-Hunt, L.L.C.*, 2009 ND 124, ¶ 20, 768 N.W.2d 496); *see also* Vol. XXVII, No. 2 (2010) of this *Newsletter*. Here, the oil royalty provision at issue requires an in-kind delivery of the produced oil (although Blasi accepts royalties in cash, rather than in kind). *Blasi*, 2021 ND 86, ¶¶ 3, 12. Further, it specifies the location for delivery (i.e., in the pipeline to which lessee may connect wells on the land), and it specifies how the oil must be delivered to that location (i.e., free of cost). *Id.* ¶ 12.

Blasi argued that the valuation point contemplated under the lease was not at the well (where all reasonable post-production costs might be deducted, as argued by the defendants), but was some point downstream of the well where oil enters a pipeline. *Id.* ¶¶ 5, 13. More specifically, Blasi argued that "the pipeline," as contemplated under the lease, was not just any pipeline, but a pipeline capable of transporting oil to a refinery, "the type that is 'generally regulated by state or federal authorities for moving oil hundreds or thousands of miles, not a pipe between the wellhead and the tank battery to move oil a few feet.'" *Id.* ¶ 13. The supreme court concluded, however, that "the pipeline" referenced in the lease "connotes a location in relation to the well; it does not designate a specific type of pipe as 'the pipeline.'" *Id.* ¶ 14. Thus, the court had no need to "look to any industry standard definition of a pipeline or parse the different types of pipes used in the oil and gas industry." *Id.* Indeed, the court found that Blasi's interpretation would introduce uncertainty.

> Under Blasi's reading, the parties would have to examine the physical characteristics of various pipes to determine whether they are "the pipeline." Based on changes to infrastructure, the valuation point could shift over time. There is also a possibility that oil may be transported by other means and never reach the type of commercial pipeline Blasi envisions. Blasi has not provided a rationale for why the parties would have bargained for this type of unpredictability.

Id. ¶ 15.

Further, the royalty provision does not even require a pipeline, according to the court; it is optional to the lessee, who "may" connect the well to a pipeline. *Id.* ¶ 16. Although Blasi reads the word "may" to signify permission to the lessee to construct a pipeline on the land without additional agreements, the court found that there are other provisions in the lease that expressly deal with easement rights. In addition, the court reasoned that "[a] fair reading of the word 'may' signifies the lessee cannot avoid the royalty obligation by neglecting to connect a pipeline to the wells. In other words, the royalty obligation exists regardless of whether the lessee constructs a pipeline at the described location." *Id.*

Finally, the oil royalty provision requires delivery at the "wells on said land." *Id.* ¶ 17. Blasi argued that elsewhere the gas royalty provision uses the phrase "at the mouth of the well." *Id.* Thus, Blasi argued the drafter must have intended something different in the oil royalty provision, where the "at the mouth of the well" language was not used. *Id.* The court disagreed, reasoning that Blasi's argument does not explain why the parties would contemplate a fixed valuation location for gas royalty valuation but a shifting valuation location for oil that could change based on the type of transportation method. *Id.* Instead, the distinction in language used more reasonably corresponds with the differing royalty delivery methods—"[t]he oil royalty requires in-kind distribution while the gas royalty requires an in-cash distribution." *Id.* Overall, the court held that the oil royalty provision unambiguously establishes a valuation point at the well. *Id.* ¶ 18.

Editor's Note: The reporter's law firm represented multiple defendants in the several actions consolidated before the North Dakota Supreme Court.

OHIO – OIL & GAS

J. Richard Emens, Sean Jacobs & Cody Smith
– Reporters –

Ohio Appellate Court Determines Vertical Limits of Adverse Possessor's Rights to Oil and Gas

In a case of first impression, the Ohio Seventh District Court of Appeals held in *Tomechko v. Garrett*, 2021-Ohio-1377 (7th Dist.), that a surface owner who adversely possessed shallow oil and gas pursuant to an oil and gas lease with no depth restriction adversely possessed *all* depths.

Tomechko involved competing claims of ownership of oil and gas minerals underlying 60.24 acres in Beaver Township, Noble County, Ohio. In 1957, the property was owned by Herbert Garrett and John Garrett. *Id.* Herbert Garrett died in 1965 leaving the property to his wife, Mary Geneva Garrett. In 1979 Mary Geneva Garrett conveyed the property to Coralee Garrett, the wife of John Garrett, while reserving one-half of the minerals. After two more transfers, the property was conveyed to James and Margaret Anderson in 1979. In 1989 the Andersons entered into an oil and gas lease (Anderson Lease) with Trans Atlantic Energy Corp. that covered the property. Two oil and gas wells were drilled on the property in 1991 pursuant to the Anderson Lease and have produced oil and gas ever since. In 2010 the property was conveyed to Gerald J. and Denise M. Tomechko. Beginning three years later, the heirs of Mary Geneva Garrett (Garrett Heirs) signed oil and gas leases covering the oil and gas they claim they inherited from Mary Geneva Garrett. *Id.* ¶¶ 2–11. In 2016, the Tomechkos filed a lawsuit against the Garrett Heirs seeking to quiet title to the oil and gas minerals under the property pursuant to, in part, adverse possession. *Id.* ¶¶ 14, 16.

The trial court issued partial summary judgment in favor of the Tomechkos, finding that they adversely possessed the oil and gas through the oil and gas wells drilled pursuant to the Anderson Lease. *Id.* ¶ 19. However, because these oil and gas wells were drilled into the shallow rights only, the trial court found that the Tomechkos were not in "exclusive" possession of the deep rights. *Id.* Thus, the trial court granted summary judgment in favor of the Tomechkos, but only to the shallow rights. *Id.* On appeal, the Seventh District held that neither the Tomechkos nor the Garretts cited any case law directly addressing the vertical limits of an adverse possessor's rights to minerals. *Id.* ¶ 54. The court also did not find any Ohio law on point. Instead, it relied on a Kentucky decision, *Diederich v. Ware*, 288 S.W.2d 643, 645–46 (Ky. 1956), which discussed the "fugacious nature of oil and gas" allowing an adverse possessor to claim title to all oil and gas under a property, even if the oil and gas well had not yet affected certain formations. *Tomechko*, 2021-Ohio-1377, ¶ 56. The Seventh District held that because the Anderson Lease did not contain a depth restriction, the Tomechkos could adversely possess *all* depths under a theory of "color of title." *Id.* ¶ 57.

Tomechko is a case of first impression in Ohio. The Seventh District commented that case law is not "uniform in determining whether working part of a mineral estate is sufficient to give title to the mineral underlying the whole of it." *Id.* ¶ 56. Thus, this case is important because it provides Ohio's law on the issue. As oil and gas companies seek to drill new oil and gas wells in Ohio, *Tomechko* may provide questions of ownership where a historical oil and gas well has been drilled.

OKLAHOMA – OIL & GAS

James C.T. Hardwick
– Reporter –

No Breach of Contract Claim Against Operator for Failure to Properly Pay Royalty Where Operator Owned No Interest in the Lease

In the case of *Brown v. Newfield Exploration Mid-Continent, Inc.*, No. 5:19-cv-00600, 2021 WL 1026526 (W.D. Okla. Mar. 17, 2021), the plaintiff was the owner of mineral interests under a section of land in Stephens County, Oklahoma, which were leased to Heritage Resources-NonOp, LLC (Heritage) pursuant to various oil and gas leases. Under the terms of the leases, the plaintiff is entitled to receive a royalty of 1/4 of gross proceeds free of all costs except taxes. Defendant Newfield Exploration Mid-Continent, Inc., the operator, completed various horizontal wells under the section at issue. The plaintiff alleged that the defendant, as operator of the wells, was responsible for paying the plaintiff's royalties but paid them incorrectly on the basis of a 1/8 royalty, rather than a 1/4 royalty. The defendant corrected that error and remitted the proper payment. However, the plaintiff claims the defendant failed to include the mandatory interest for untimely payments under the Production Revenue Standards Acts (PRSA), Okla. Stat. tit. 52, §§ 570.1–.15. The plaintiff filed suit claiming breach of contract, negligence, unjust enrichment, and violation of the PRSA. The defendant sought dismissal of the plaintiff's claims. However, the parties reached a resolution on the claims for violation of the PRSA, negligence, and unjust enrichment, leaving only claims for breach of contract and improper cost deductions from the plaintiff's royalty. *Brown*, 2021 WL 1026526, at *1.

The defendant contended the plaintiff failed to state a claim for breach of contract because it had failed to state a contract to which the defendant was a party. The complaint did not identify a contract between the plaintiff and the defendant, but instead only alleged that the defendant breached the terms of the plaintiff's lease with Heritage by failing to pay the amount due under the lease. The plaintiff did not dispute that the defendant was not a signatory to the leases, but contended that the defendant as operator of record, pursuant to Oklahoma Corporation Commission orders, had thereby agreed to or otherwise assumed the obligation to comply with the terms of the leases with Heritage. *Id.* at *2.

The court dismissed the breach of contract claim noting that contracts are binding upon those who are parties to it or, if the contract is assigned, then upon an assignee who stands in the shoes of the assignor and acquires all of assignor's rights and liabilities. *Id.* The defendant was not a signatory to the leases and the plaintiff had failed to plead any facts plausibly suggesting assignment of Heritage's obligations under the lease. *Id.* The court rejected the plaintiff's unsupported contention that the defendant, simply by reason of its status as operator, could be held liable for breach of contract based upon failure to fulfill Heritage's contractual duties under its leases. *Id.* The plaintiff's contract claims were thereby dismissed. *Id.*

The defendant next argued that there was no claim stated for underpaid royalties based upon improper cost deductions. *Id.* The plaintiff's sole allegation in this respect was that the defendant has breached the terms of the leases by failing to pay the plaintiff 1/4 royalty on the plaintiff's proportionate share of gross production, free from all deduction of costs and expenses from the wells drilled and completed on the applicable section. *Id.* The plaintiff failed to specify which costs were improperly deducted or provide any facts that might place the defendant on notice of its alleged misconduct. *Id.* The court noted the plaintiff's reference to costs failed to provide the factual context required to state a plausible claim for relief. *Id.* Moreover, the plaintiff's improper cost deduction claim sounds in contract and the court had already determined that the plaintiff failed to allege a contractual relationship with the defendant. *Id.* at *3. Thus that claim was likewise dismissed. *Id.*

Finally, the court denied the plaintiff's motion for leave to amend because under local rules the proposed pleading must be attached to the motion, which it was not. *Id.* The denial was without prejudice but subject to the submission of a motion complying with local rules. *Id.* The court noted however that in reviewing any proposed amendment, the court would consider whether the plaintiff had failed to cure the deficiencies by amendment and whether the amendment would be futile. *Id.*

Filing of New Leases in 1984 Purporting to Cover the Marmaton Formation Did Not Trigger Running of 15-Year Statute of Limitations as Against Holder of Overriding Royalty in the Formation Under 1973 Lease

In the case of *Claude C. Arnold Non-Operated Royalty Interest Properties, L.L.C. v. Cabot Oil & Gas Corp.*, 2021 OK 4, 485 P.3d 817, Arnold Petroleum, Inc., a predecessor to the plaintiffs (collectively, Arnold), obtained six oil and gas leases covering land in Beaver County, Oklahoma. These leases had a primary term of three years plus provisions for a five-year extension. However, there was a special clause (Exceptions Clause) that provided that the lessee was not obligated to release any formation, horizon, or zone, the production from which would conflict with any existing producing horizon, formation, or zone. Between 1973 and 1974, Arnold assigned its leases to Dyco Petroleum Corporation (Dyco) expressly reserving an overriding royalty interest on produced oil and gas. Subsequently Dyco assigned the leases to Harold Courson, predecessor-in-interest to the defendant, Cabot Oil & Gas Corp. (Cabot). The assignment was expressly made subject to Arnold's existing override. Before the end of the leases' primary term, Courson drilled and completed two vertical wells in the Chester formation, which underlies the lands covered by the 1973 leases. These wells produced continuously beginning in the mid-1970s, and at all times during that period Arnold was paid on its overriding royalty in those wells. *Id.* ¶¶ 3–5.

The primary terms of the 1973 leases ended in 1976 but they were extended under their five-year option as to open formations. In 1984, Courson obtained new leases from the owners who had granted the 1973 leases. These leases purported to cover the same rights as the 1973 leases. In 1999, Arnold and other royalty owners received a letter from Courson explaining that he had recompleted a well in the Chester formation that had originally been completed in a lower formation by another company. After learning that the recompleted well would be now producing from the Chester where Arnold had retained its override, Arnold's landman contacted Courson. In an ensuing conversation, Courson's landman claimed the 1984 leases covered only the deep rights or lower zones that had expired under the 1973 leases. That assertion if true would have excluded the Marmaton formation, which is a shallower formation above the Chester. Nothing more was said about the matter for the next 13 years. *Id.* ¶ 6.

In August 2011, Courson assigned its leases to Cabot and Cabot thereupon drilled and completed two horizontal wells that began producing in the first half of 2012. Arnold contacted Cabot requesting payment on its override, claiming that its rights in the Marmaton formation were held by virtue of the 1973 leases' Exceptions Clause. Arnold further claimed that the Marmaton had always been capable of producing oil and gas in paying quantities but had been prevented from doing so by conflict caused by the simultaneous production from the vertical wells completed in the Chester in the 1970s. Cabot rejected Arnold's request for payment. Arnold sued in October 2012 for nonpayment of royalties and to quiet title to its overriding royalty interest as to the Marmaton formation. Cabot claimed in return that Arnold's claims were barred by the statute of limitations that was claimed to have commenced to run with the filing of the new leases in 1984, which Cabot claimed should have put Arnold on notice of an adverse claim to the Marmaton.

After a bench trial, the court found that Arnold's cause of action accrued July 20, 2012, which was the date Arnold's representative contacted Cabot to request payment on the override. Arnold was granted judgment quieting title to the overriding royalty interest and was awarded damages and prejudgment interest accordingly. *Id.* ¶¶ 7–8.

Cabot appealed. The Oklahoma Court of Civil Appeals agreed with Cabot that Arnold's claim accrued in 1984 upon the filing of the new leases in the land records and reversed the trial court's judgment on the grounds that the 15-year statute of limitations applicable to recovery of interests in real property barred Arnold's claims as untimely. *Id.* ¶ 9 (citing Okla. Stat. tit. 12, § 93(4)). That court further concluded that Arnold would have needed to have sued no later than 1999 to avoid bar by the 15-year statute of limitations and to keep its Marmaton rights. *Id.* Arnold petitioned for certiorari to the Oklahoma Supreme Court and it was granted. *Id.* Upon review the supreme court reversed the court of civil appeals.

The supreme court began with statement that Arnold's cause of action arose when the "injury occurs," *id.* ¶ 12 (quoting *Calvert v. Swinford*, 2016 OK 100, ¶ 11, 382 P.3d 1028); *see* Vol. XXXIII, No. 4 (2016) of this *Newsletter*, further stating "the cause of action accrues when a litigant first could have maintained [an] action to a successful conclusion," 2021 OK 4, ¶ 12 (quoting *MBA Commercial Constr., Inc. v. Roy J. Hannaford Co.*, 818 P.2d 469, 473 (Okla. 1991)). So the question was, "when was Arnold 'injured,' such that it could successfully sue to establish its rights to the Marmaton formation?" *Id.* Cabot contended that once the 1984 leases were filed in Beaver County, Arnold was put on notice of an adverse interest jeopardizing the ongoing validity of its overriding royalty interest and the clock began to run on any potential cause of action to quiet title, thus triggering the running of the 15-year statute of limitations. *Id.* ¶ 13. However, the court found evidence at trial supported the triggering of the Exceptions Clause in the 1973 leases permitting the Marmaton formation to be held by production from the Chester formation under the plain language of that clause. *Id.* ¶ 14. Further the Chester formation had produced continuously since the mid-1970s, and Arnold had never stopped receiving overriding royalty payments on that production. *Id.* The filing of the 1984 leases did not alter those facts. *Id.* The supreme court found that "[n]othing in the 1984 leases suggested the parties . . . considered the 1973 leases terminated as to the Marmaton." *Id.* ¶ 16. When Arnold spoke to Courson in 1999 about the 1984 leases, the Marmaton formation and its status never came up. *Id.* Returning to the effect of the Exceptions Clause, the court said that

> [u]nder its plain terms, a nonproducing zone capable of producing hydrocarbons in commercial quantities—here, the Marmaton formation—but unable to do so because of a conflict with existing production in another zone—here, the Chester formation—would nevertheless remain held by production in that latter zone for the duration of the lease.

Id. ¶ 17.

After further analysis of the facts and the interplay of the Exceptions Clause, the court held that the Marmaton formation was held by production from the Chester formation, the conduct of the parties for over 40 years showed an intent to keep paying Arnold for its override under the 1973 leases, the recording of the 1984 leases did not change that, and nothing supported any requirement that Arnold sue no later than 1999 (upon which the 15-year statute of limitations claim was based) for an injury that would not have occurred until 2012. *Id.* ¶ 20. The court concluded that "no injury occurred to Arnold before July 2012, when it first requested payment of its overriding royalty interest." *Id.* ¶ 12. Thus, Arnold timely filed suit to vindicate its interest. *Id.* ¶ 20. The court affirmed the judgment of the trial court in all respects. *Id.*

PENNSYLVANIA – MINING

Joseph K. Reinhart, Sean M. McGovern & Gina N. Falaschi
– Reporters –

PADEP's RGGI Rule Nears the End of the Regulatory Process

Continuing from previous issues of this *Newsletter*, this report provides recent updates on the Pennsylvania Environmental Quality Board's (EQB) proposed CO_2 Budget Trading Program rulemaking, which would link Pennsylvania's program to and implement the Regional Greenhouse Gas Initiative (RGGI) within the commonwealth beginning in 2022. *See* Vol. XXXVIII, No. 2 (2021), Vol. XXXVIII, No. 1 (2021), Vol. XXXVII, No. 4 (2020), Vol. XXXVII, No. 3 (2020), Vol. XXXVII, No. 2 (2020), Vol. XXXVII, No. 1 (2020), Vol. XXXVI, No. 4 (2019) of this *Newsletter*. RGGI is the country's first regional, market-based cap-and-trade program designed to reduce carbon dioxide (CO_2) emissions from the power sector. The proposed regulation would limit CO_2 emissions from Pennsylvania's fossil fuel-fired electric generating units with a nameplate capacity of 25 megawatts or greater that send more than 10% of their annual gross generation to the electric grid. The proposed initial emissions cap for Pennsylvania in 2022 is 78 million tons of CO_2, which would decline annually.

The public comment period for the proposed rule ran from November 7, 2020, until January 14, 2021. The Independent Regulatory Review Commission (IRRC) released its comments on February 16, 2021. *See* Comments of the Independent Regulatory Review Commission, Environmental Quality Board Regulation #7-559 (IRRC #3274, CO2 Budget Trading Program (Feb. 16, 2021). The IRRC recommended that EQB (1) explain the choice to institute the program through regulation rather than legislation; (2) provide analysis of its statutory authority to enact the proposal; (3) consider recommendations from commentators on public health, safety, and welfare, economic or fiscal impact, and adequacy of data; and (4) delay implementation of the rulemaking for one year to give the regulated community an opportunity to adjust business plans to account for increased costs associated with Pennsylvania joining RGGI. *Id.*

In response to public comment, in March 2021, the Pennsylvania Department of Environmental Protection (PADEP) announced a set of equity principles to help inform the public on the implementation of the RGGI program and investments of the program's proceeds. *See* Press Release, PADEP, "Wolf Administration Announces Equity Principles to Guide Investments Through Regional Greenhouse Gas Initiative" (Mar. 10, 2021). PADEP also engaged a contractor, the Delta Institute, to develop a plan to invest RGGI auction proceeds to diversify Pennsylvania's economy and assist communities affected by changes in the energy sector.

PADEP released the final form rulemaking for the CO_2 Budget Trading Program ahead of presenting the regulation to the Air Quality Technical Advisory Committee, Citizens Advisory Council, and Small Business Compliance Advisory Counsel at their May 2021 meetings. All three committees voted in support of advancing the rulemaking. Further information regarding these meetings and presentations can be found on PADEP's RGGI webpage at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

In early July 2021, PADEP released the comment and response document and additional regulatory documents for its CO_2 Budget Trading Program. *See id.* PADEP's final rule included a number of changes from the draft rule, including quarterly CO_2 allowance budgets for 2022 in the event that Pennsylvania joins RGGI part way through the year, a modification to the limited exemption, expansion of the cogeneration (now combined heat and power) set-aside with qualifiers, adjustment of the waste coal set-aside allowances, clarifications to the strategic use set-aside, an additional PADEP commitment to perform an annual air quality impact assessment, and incorporating the equity principles. At its July 13, 2021, meeting, EQB debated and voted 15-4 to adopt the final regulation.

The final regulation will be presented to the Pennsylvania House and Senate Environmental Resources and Energy Committees and the IRRC for approval. The IRRC plans to consider the rule at its September 1, 2021, meeting. *See id.* If approved by the IRRC and the legislative committees, the regulation will be submitted to the Attorney General's Office, and if approved, published in the *Pennsylvania Bulletin* as a final rule. Governor Tom Wolf intends to finalize the regulation by the end of 2021, and regulated entities could be required to begin compliance on January 1, 2022.

The rulemaking, however, continues to face opposition from regulated industry and the general assembly. Despite Governor Wolf's veto of a bill that would have prohibited PADEP from adopting a greenhouse gas cap-and-trade program without specific statutory authorization in September 2020, *see* Vol. XXXVII, No. 4 (2020) of this *Newsletter*, the current legislature has continued to advance similar legislation in 2021. In January 2021, Senator Joe Pittman introduced Senate Bill 119, 204th Leg., Reg. Sess. (Pa. 2021), which would require legislative approval before PADEP could impose a carbon tax on employers engaged in electric generation, manufacturing, or other industries operating in the commonwealth, or enter into any multistate program, such as RGGI, that would impose such a tax. The bill passed 35-15 in the Senate on June 14, 2021, and was sent to the House Environmental Resources and Energy Committee on June 15, 2021. Unlike the legislation vetoed in 2020 by Governor Wolf, Senate Bill 119 passed with a veto-proof majority in the Senate.

The rulemaking has also gained support in the general assembly. On June 4, 2021, Senator Carolyn Comitta announced that she would introduce legislation, the RGGI Investment Act, to create the proposed RGGI funding program. *See* Senate Bill 15, 204th Leg., Reg. Sess. (Pa. 2021). The legislation would establish several trust funds to distribute the estimated $300 million annual revenue generated through RGGI auctions. These funds would make targeted investments to support environmental justice communities, workers affected by energy transition, and Pennsylvania's growing clean energy and commercial and industrial sectors. The bill was referred to the Senate Environmental Resources and Energy Committee on July 26, 2021.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart, Sean M. McGovern,
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– Reporters –

Supreme Court of Pennsylvania Dismisses Appeal of Unconventional Drilling Zoning Approvals

On June 22, 2021, a few weeks after hearing oral arguments, the Supreme Court of Pennsylvania dismissed as having been improvidently granted appeals by environmental advocacy group Protect PT to overturn two Penn Township Zoning Hearing Board (Board) decisions to grant special exceptions for gas well development in the township. *Protect PT v. Penn Twp. Zoning Hearing Bd.*, 252 A.3d 600 (Pa. 2021) (mem.).

The companion cases originated from the Board's 2018 decisions to approve special exception applications by Olympus Energy LLC (Olympus) to develop oil and gas operations at two well pads in Penn Township, Westmoreland County, Pennsylvania. In the hearings, Protect PT asserted that the cumulative impacts of the gas well development near residential neighborhoods could increase the probability of negative environmental, safety, and health impacts in the community. The Board ultimately approved Olympus's applications, concluding the proposed development satisfied the requirements of the township's zoning ordinance (subject to certain conditions) and that Protect PT failed to present sufficient, credible evidence to rebut the Board's conclusion.

Protect PT first appealed the Board's decisions to the Westmoreland County Court of Common Pleas, which denied the appeals and affirmed the Board's decisions without taking additional evidence. Protect PT subsequently appealed to the Commonwealth Court of Pennsylvania. Before the commonwealth court, Protect PT argued that the Board capriciously disregarded the evidence presented to it in granting Olympus's applications. *See Protect PT v. Penn Twp. Zoning Hearing Bd.*, 238 A.3d 530 (Table), 2020 WL 3640001 (Pa. Commw. Ct. 2020), *appeal granted in part*, 243 A.3d 969 (Table) (Pa. 2021), *appeal dismissed as improvidently granted*, 252 A.3d 600 (Pa. 2021) (mem.). Thus, Protect PT argued, the Board erred in determining that the well pad development "would not create a high probability of adverse, abnormal, or detrimental effects on public health, safety, and welfare based on related increased traffic and air emissions during its development and operation." *Id.* at *6.

Citing precedent, the commonwealth court stated that it could not substitute its interpretation of the evidence for the Board's, whose function is to weigh the evidence before it as "the sole judge of the credibility of witnesses and the weight afforded their testimony" and that the Board "is free to reject even uncontradicted testimony it finds lacking in credibility, including testimony offered by an expert witness. It does not abuse its discretion by choosing to believe the opinion of one expert over that offered by another." *Id.* at *7 (quoting *Taliaferro v. Darby Twp. Zoning Hearing Bd.*, 873 A.2d 807, 811 (Pa. Commw. Ct. 2005)). In reviewing the evidence considered by the Board, the commonwealth court found that Protect PT failed to present credible evidence of the alleged negative effects that would result from approving the well pad operations and that the Board did not err in granting the Olympus application. *Id.* at *9, *13. Protect PT petitioned the Supreme Court of Pennsylvania to allow it to appeal, which the court granted, limiting review to specific issues. *Protect PT v. Penn Twp. Zoning Hearing Bd.*, 243 A.3d 969 (Table) (Pa. 2021); *see* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. Before the supreme court, Protect PT contended that the Board should not be allowed to reject without explanation its expert's evidence of the cumulative negative impacts of well development as not credible. The court concluded that it would take the matter under advisement and, as stated above, dismissed the appeals a few weeks later.

Corps Issues Pennsylvania State Programmatic General Permit-6

On June 25, 2021, the Philadelphia, Pittsburgh, and Baltimore Districts of the U.S. Army Corps of Engineers (Corps) jointly announced the issuance of the Pennsylvania State Programmatic General Permit-6 (PASPGP-6) for a five-year period, effective July 1, 2021, for applicable parts of Pennsylvania. *See* Corps, Special Public Notice # SPN-21-28 (June 25, 2021). The PASPGP is the mechanism that the Pennsylvania Department of Environmental Protection (PADEP) and the Corps rely upon to permit most projects in Pennsylvania that impact federally regulated waters, but do not require an individual section 404 permit. PASPGP-6 allows applicants to obtain both federal section 404 permits and state water obstruction and encroachment permits for projects impacting federal and state regulated waters. PASPGP-6 replaces Pennsylvania State Programmatic General Permit-5 (PASPGP-5), which became effective July 1, 2016, was revised in July 2018, and expired on June 30, 2021. PASPGP-6 authorizes work in waters of the United States within portions of Pennsylvania for activities that would cause no more than minimal adverse environmental effects, individually and cumulatively, subject to the permit's specific terms and conditions, and operates in conjunction with the relevant PADEP state regulatory program.

PASPGP-6 changes a number of elements from PASPGP-5. For example, PASPGP-6 updates the following eligibility thresholds: (1) PASPGP-5's one-acre threshold for single and complete projects (temporary and/or permanent impacts of one acre) was changed to 0.5 acre of permanent loss of waters of the United States, including jurisdictional wetlands (with some exceptions); and (2) PASPGP-5's one-acre threshold for temporary impacts to waters of the United States, including jurisdictional wetlands, was changed in PASPGP-6 to unlimited acreage, as long as the work is determined to result in no more than minimal impact. *Id.*

In addition, PASPGP-6 updates the reporting threshold for Corps review of an application, which is now calculated based on impacts associated with an overall project. The reporting threshold under PASPGP-5 applied to single and complete projects. As noted above, the eligibility threshold determination under PASPGP-6 is made based on single and complete projects. *Id.* In another change, section 10 waters within the Pittsburgh District (previously ineligible under PASPGP-5) are eligible for authorization under PASPGP-6 (which requires Corps review unless the work qualifies for authorization under PADEP Waivers 10 and 12). *Id.* The PASPGP-6 full permit and related materials are available on the Corps' website at https://www.nab.usace.army.mil/Missions/Regulatory/Permit-Types-and-Process.

U.S. District Court Dismisses Challenge to DRBC's Hydraulic Fracturing Ban

On June 11, 2021, the U.S. District Court for the Eastern District of Pennsylvania dismissed a lawsuit challenging the authority of the Delaware River Basin Commission (DRBC) to ban hydraulic fracturing within the Delaware River Basin (Basin). *See Yaw v. DRBC*, No. 2:21-cv-00119, 2021 WL 2400765 (E.D. Pa. June 11, 2021).

In 2009, the DRBC, citing concern for adverse environmental effects, instituted a moratorium prohibiting hydraulic fracturing "within the drainage area of the basin's Special Protection Waters," unless previously approved by the DRBC. News Release, DRBC, "DRBC Eliminates Review Thresholds for Gas Extraction Projects in Shale Formations in Delaware Basin's Special Protection Waters" (May 19, 2009). The moratorium was expanded in 2010 and remained in effect until February 2021 when the DRBC memorialized the moratorium as a ban via regulation. *See* News Release, DRBC, "Wastewater Importation and Water Exportation Rule Amendments to Be Proposed" (Feb. 25, 2021). Seeking declaratory judgment and injunctive relief against the DRBC, two Pennsylvania state senators, Gene Yaw and Lisa Baker, and their caucus, and two Pennsylvania townships and two counties located within the Basin filed suit in federal court in January 2021. The plaintiffs alleged that the moratorium (1) exceeds the DRBC's authority under the Delaware River Basin Compact, (2) is an unconstitutional taking of private and public property, (3) is an illegal usurpation of the commonwealth's power of eminent domain, and (4) violates the constitutional guarantee of a republican form of government. *Yaw*, 2021 WL 2400765, at *3.

The question before the court was whether the plaintiffs had standing to bring their claims. The state senator plaintiffs argued, among other things, general injuries to the commonwealth and its citizens, as well as injuries against the general assembly's power and authority. *Id.* at *5. The court rejected these arguments, finding that any such powers were vested in the general assembly or commonwealth, not individual senators. *Id.* at *6. The state senator plaintiffs also argued that Pennsylvania law provides them with interests sufficient to confer standing, and that their role as "trustees" under the Pennsylvania Environmental Rights Amendment (ERA) conferred standing. *Id.* (citing Pa. Const. art. I, § 27). Finding that these arguments amounted to nothing more than the state senator plaintiffs asking the court to substitute "friendlier state standards" for those under Article III of the U.S. Constitution, the court rejected them. *Id.* at *7. Citing precedent, the court likewise rejected the argument that Yaw, Baker, and their caucus are trustees for the commonwealth natural resources, noting that such authority is vested in Pennsylvania agencies or entities. *Id.* at *8 (citing *Pa. Envtl. Def. Found. v. Commonwealth*, 161 A.3d 911, 931–32 & n.23 (Pa. 2017)).

Regarding the municipal plaintiffs, the court found that they had obligations as trustees under the ERA but had failed to allege a cognizable injury that would confer standing under Article III. *Id.* at *9. That is, the court found, their arguments that "loss of funds" that would have flowed to the municipalities had fracking occurred within their boundaries were too speculative and did not show a current or recent injury, not to mention the requirements of traceability and redressability. *Id.* Despite the municipal plaintiffs' failure to meet the burden to demonstrate standing, the court noted that articulating actual injury may be possible and allowed them to file a second amended complaint. *Id.* at *10.

The municipalities did not file a second amended complaint and on July 2, 2021, the court dismissed their claims (and the amended complaint) with prejudice. On July 12, 2021, the state senators, their caucus, and three of the municipalities appealed the dismissal of their claims to the U.S. Court of Appeals for the Third Circuit. *See Yaw v. DRBC*, No. 21-2315 (3d Cir. filed July 19, 2021).

Substantial Changes to Hazardous Liquid Pipeline Safety Regulations Proposed by Public Utility Commission

On July 15, 2021, the Pennsylvania Public Utility Commission (PAPUC) adopted a notice of proposed rulemaking (NOPR) with proposed changes to the regulations for the design, construction, operations, and maintenance of intrastate pipelines transporting petroleum products and hazardous liquids in Pennsylvania. *See* PAPUC, Docket Number L-2019-3010267. The proposed changes are significant and in several respects would exceed the Pipeline and Hazardous Materials Safety Administration's (PHMSA) federal pipeline safety standards and reporting requirements, which PAPUC incorporates by reference. Comments are due 60 days from the date that the NOPR is published in the *Pennsylvania Bulletin*. A brief summary of the key proposals is provided below.

<u>Reporting (§§ 59.133–.134)</u>

- Proposes a time frame and associated requirements for the submittal of an unredacted failure analysis, which must be conducted by a PAPUC-approved, independent third-party consultant following a reportable accident.
- Proposes that a public utility notify PAPUC prior to construction, reconstruction, maintenance, or assessment activities and sets time frames for the notification based upon project cost. Requires immediate notification of excavation damages, washouts, or unplanned replacement of any pipeline section or cutout.

<u>Design and Construction (§§ 59.135–.138)</u>

- Proposes several design and construction requirements for new pipelines and existing pipelines that are converted, relocated, replaced, other otherwise changed, including analysis of geotechnical conditions, design for geological hazards, setbacks, minimum depth of coverage, testing methodologies, and numerous construction and safety requisites.
- Requires pipelines installed using horizontal directional drilling (HDD), trenchless technology (TT), or other direct bury methodologies to comply with relevant Pennsylvania Department of Environmental Protection (PADEP) regulations protecting water wells and supplies and PADEP's "Trenchless Technology Technical Guidance Document."
- Establishes notification requirements prior to commencing HDD, TT, or other direct bury methods, or in the event private or public water supplies are adversely impacted.
- Proposes notification requirement and several in-line and hydrostatic testing schedules, including for pipelines installed prior to 1970, pipelines installed after 1970, and following leak repair.

<u>Operations and Maintenance (§ 59.139)</u>

- Proposes several operations and maintenance requirements, including emergency response procedures, liaison activities with emergency responders and school administrators, public awareness communications, line markers, inspections of rights-of-way, leak detection, and odorization.

<u>Integrity Management (§ 59.139)</u>

- Requires public utilities to consult with public officials when determining the need for remote control emergency flow restriction devices (EFRD) in all high consequence areas and base the need for EFRD on limiting the lower flammability limit to 660 feet on either side of the pipeline.

<u>Operator Qualifications (§ 59.140)</u>

- Significantly expands a public utilities operator qualification program by modifying "covered task" as defined in PHMSA's federal regulations.
- Requires that a public utilities operator qualification plan include a written qualification program for construction tasks, processes for training all individuals to identify and react to facility-specific abnormal operating conditions, and requalification intervals for each covered task.

<u>Land Agents (§ 59.141)</u>

- Requires that land agents hold a valid professional license as an attorney, real estate salesperson, real estate broker, professional engineer, professional land surveyor, or professional geologist in Pennsylvania.

<u>Corrosion Control (§ 59.142)</u>

- Requires written procedures for the design, installation, operations, and maintenance of cathodic protection systems, including establishing average and worst-case corrosion rates for each pipeline segment.

TEXAS – OIL & GAS

William B. Burford
– Reporter –

Summary Judgment for Disposal Injection Well Operator on Limitations Defense Held Improper

The court in *Regency Field Services, LLC v. Swift Energy Operating, LLC*, 622 S.W.3d 807 (Tex. 2021), *rev'g* 608 S.W.3d 214 (Tex. App.—San Antonio 2019), reversed a summary judgment that had been granted Regency Field Services, LLC (Regency), the operator of a hydrogen sulfide gas disposal well, the Tilden Acid Gas Injection Well, in McMullen County, Texas, against Swift Energy Operating, LLC (Swift), the lessee of oil and gas leases on nearby land that Swift alleged were being damaged by the migration of injectate from Regency's well.

The 4,200-acre Quintanilla Ranch was adjacent to the disposal well's location. One of Swift's leases, its PCQ lease, covered the Quintanilla Ranch except tracts immediately surrounding wells drilled and producing under earlier leases, including Layline Petroleum's (Layline) JCB Horton #1. Layline had to plug the Horton #1 because of hydrogen sulfide contamination, and it notified Swift that it had done so on October 23, 2012. Because Swift's leasehold acreage lay between Regency's disposal well and the Horton #1, Swift must have known by that date that hydrogen sulfide gas had migrated into land covered by its PCQ lease. In July 2014 the Quintanilla family, owners of the ranch, filed suit against Regency for subsurface damage allegedly caused by the migration of gas from Regency's well into their land. Swift intervened in the suit on September 24, 2015. The court of appeals, reversed here by the supreme court, had held that Swift's claim for damage to its PCQ lease was barred by the two-year statute of limitations as a matter of law because it had not been brought within two years after Swift knew that Regency's hydrogen sulfide gas had migrated underneath its lease. *Id.* at 811–13; *see* Vol. XXXVI, No. 2 (2019) of this *Newsletter*.

The court began its analysis by noting that "a defendant seeking summary judgment based on limitations must conclusively establish that the limitations period expired before the claimant filed suit." *Regency*, 622 S.W.3d at 818. "To do this," it went on, "the defendant must conclusively establish when the claimant's action accrued." *Id.* The court concluded that Swift's pleaded allegations and the summary judgment evidence failed to conclusively establish that Swift suffered a legal injury as a result of Regency's alleged wrongful conduct on or before September 24, 2013, two years before Swift's intervention. *Id.* at 823.

"In the first place," the court observed, "the migration of the injectate beneath . . . Swift's lease[] did not *necessarily* cause Swift to sustain a legal injury." *Id.* at 820. The mere fact that contaminants had migrated into the subsurface space covered by Swift's lease did not conclusively establish that its use and enjoyment of the land for oil and gas development had been interfered with, or when it might have done so. *Id.* "[T]he statute of limitations may very well bar Swift's claims" based on facts established at trial or after further discovery, the court remarked, but neither the fact that gas had migrated underneath the PCQ lease more than two years before Swift's intervention nor Swift's allegations that Regency's conduct had already caused it injury and would result in future injury conclusively established that Swift was injured before September 24, 2013. *Id.* at 824.

Correction Deed Executed by Parties to Original Deed Held Effective as to Royalty Previously Sold to Others

The court in *Broadway National Bank v. Yates Energy Corp.*, No. 19-0334, 64 Tex. Sup. Ct. J. 982, 2021 WL 1940042 (Tex. May 14, 2021), *rev'g* 609 S.W.3d 140 (Tex. App.—San Antonio 2018), construed Texas's peculiar correction instrument statute in the context of a dispute over ownership of royalty interests in DeWitt and Gonzales Counties, Texas.

The interests in question had been property of a trust created by Mary Frances Evers for the benefit of four of her children, including her son John, of which Broadway National Bank was the trustee. Although John's 25% share of the trust property was to benefit him only during his life and then vest in others, the bank, apparently by mistake, executed a deed in 2005 after the trustor's death in which it conveyed his share of the property to him in fee simple. The bank, as trustee, in 2006 executed a correction deed, not joined by John, in which it purported to replace the 2005 conveyance with a life estate to John, with remainder to those his mother had designated to take his share on his death. Several years later, in 2012, John executed a deed conveying his royalty interests to Yates Energy Corporation (Yates), which subsequently conveyed the interests to others. After a title attorney questioned the effectiveness of the bank's 2006 correction deed, the bank and all of the original parties to the 2005 deed, including John but not Yates or those to whom it had conveyed, executed an amended correction deed in November 2013 under which John was conveyed only a life estate in the property. *Id.* at *1–3.

John died a few months later, and litigation ensued between the bank, joined by the remaindermen, who maintained that Yates had acquired only John's life estate, and Yates and its assignees, who argued that the bank's 2005 conveyance to John in fee simple was binding and enforceable and the correction deeds were invalid. The trial court granted summary judgment to the bank and the remaindermen, but the court of appeals reversed, holding that the 2013 correction deed was not valid without having been joined by the current owners of John's interest. *Id.* at *3–4; *see* Vol. XXXVI, No. 1 (2019) of this *Newsletter*. The supreme court reversed the court of appeals.

The bank contended that its 2013 correction deed complied with Tex. Prop. Code §§ 5.027–.031, a set of statutes providing for the use of correction instruments to remedy errors in real property conveyances, enacted in 2011 in response to dicta in *Myrad Properties, Inc. v. LaSalle Bank National Ass'n*, 300 S.W.3d 746 (Tex. 2009), that had needlessly appeared to call into question the general effectiveness of correction instruments. Section 5.029 provides that an instrument correcting a material error such as the one at issue here must be "executed by each party to the recorded original instrument of conveyance the correction instrument is executed to correct or, if applicable, a party's heirs, successors, or assigns." The parties disputed whether the words "or, if applicable" require correction instruments to be executed by the current owners of the property to whom a party to the instrument to be corrected has conveyed. The Yates group contended that it did, while the bank "argue[d] that 'a party's heirs, successors, or assigns' are merely substitutes whose signatures are unnecessary unless an original party is unavailable to execute the correction instrument." *Broadway*, 2021 WL 1940042, at *5.

The court agreed with the bank and held that the 2013 correction deed complied with the statute and was therefore valid. Nothing in the statutory text, in the court's view, "indicate[d] that an assign must assent to a correction instrument when each party to the original conveyance is available to correct their mistake . . . ." *Id.* at *8. Rather, according to the court, "if applicable," when read along with the disjunctive "or," "simply emphasizes that the phrase 'party's heirs, successors, or assigns' may be relevant when the original party is unavailable and, in that case, may serve as a substitute." *Id.* The court went on to observe that another portion of the legislation, Tex. Prop. Code § 5.030, makes correction instruments subject to the property interest of a bona fide purchaser acquired after the original instrument. *Broadway*, 2021 WL 1940042, at *8. That protection afforded bona fide purchasers would be pointless, the court believed, if bona fide purchasers were otherwise required to sign a correction instrument for it to take effect. *Id.* at *9. Because some of the Yates group claimed bona fide purchaser status and the court of appeals had not reached their argument for that position, the court remanded the case to the court of appeals. *Id.* at *11.

A strong four-justice dissent accused the majority of reading the words "if applicable" out of the statute altogether, allowing the former owners to strip current owners of their property without notice. The word "applicable" in the statute modifies "assign," not the original party, in the dissenting justices' analysis, and the statute, they pointed out, makes no mention of a party's availability. *Id.* at *12 (Busby, J., dissenting). "Who must execute the correction instrument," according to the dissent, "turns on the applicability of the assigns, not the availability of the original parties." *Id.*

Lessor's Acceptance of Royalty Calculated on Pooled Basis Held Not to Have Ratified Pooling

In *BPX Operating Co. v. Strickhausen*, No. 19-0567, 64 Tex. Sup. Ct. J. 1284, 2021 WL 2386141 (Tex. June 11, 2021), *aff'g Strickhausen v. Petrohawk Operating Co.*, 607 S.W.3d 350 (Tex. App.—San Antonio 2019), the Texas Supreme Court affirmed the judgment of the court of appeals reversing the trial court's summary judgment for BPX Operating Co. (BPX) against its oil and gas lessor, Margaret Strickhausen. *See* Vol. XXXVI, No. 2 (2019) of this *Newsletter*.

Strickhausen's lease on her 50% mineral interest in a tract of land in LaSalle County, Texas, expressly denied the lessee the right to pool the land without the lessor's consent. BPX nevertheless designated a pooled unit consisting of the Strickhausen tract and several others and drilled a horizontal well, its WK Unit 4 No. 1H, through the pooled unit. After the well began producing in August 2012, BPX sent Strickhausen a letter, dated September 20, 2012, asking for her ratification of the pooling. Between then and March 2013, Strickhausen's attorney and BPX communicated with each other about the request, the attorney reiterating to BPX that Strickhausen's lease could not be pooled without her consent—a point with which BPX did not disagree—and ultimately offering on Strickhausen's behalf to settle BPX's "wrongful pooling" and ratify the pooling for a "bonus" payment of $300,000. BPX did not respond to the offer. Beginning shortly after her attorney had sent his letter making the offer, Strickhausen began depositing monthly royalty checks sent her by BPX, each bearing the notation "WK UNIT 4 1H," the amounts of which were calculated according to the proportion that the acreage of her tract bore to the total acreage of the pooled unit. *BPX*, 2021 WL 2386141, at *1–3.

Strickhausen filed suit against BPX on August 1, 2014, having deposited nearly $600,000 in royalty payments by that time, claiming that because her lease required BPX to pay royalties on all production from any well on her tract, it owed her royalty on all the production from the well even though it extended horizontally into other land. BPX countered that Strickhausen had impliedly ratified the pooling by accepting royalty payments calculated on a pooled basis, and the trial court had agreed. *Id.* at *3.

In upholding the court of appeals' reversal of the summary judgment for BPX, the court began by pointing out that whether a party has ratified changes to a contract is a matter of intent, based on objective evidence of that intent. *Id.* at *5. Implied ratification or ratification by conduct, it emphasized, should be found only if the party's actions *clearly* evidence that intent, after all relevant facts and circumstances are considered. *Id.* Rejecting a categorical rule that acceptance of royalty on a pooled basis must always amount to ratification of the pooling as a matter of law, while recognizing that such acceptance may support a finding of ratification, the court found that Strickhausen's depositing the royalty checks was not so inconsistent with her denial of pooling as to constitute her ratification of it. *Id.* at *10–11. Her attorney had expressly objected to the pooling, albeit before Strickhausen began depositing the checks, and she maintained that BPX owed her significant royalties regardless of whether her lease was pooled or not, the court observed. *Id.* at *8. "Under the circumstances," according to the court, "BPX could not have reasonably inferred that Strickhausen's acceptance of the checks meant she consented to pooling." *Id.* at *10.

This was a 5-4 decision of the court, and the dissenting justices forcefully pointed out that the court had "never held that implied ratification requires *both* the acceptance of benefits from the wrongful act *and* a failure to challenge the wrongful act." *Id.* at *14 (Boyd, J., dissenting). "Either may suffice," according to the dissent. *Id.* In addition, the dissenters were unpersuaded that Strickhausen's conduct was not wholly inconsistent with her objection to the pooling. *Id.* at *17.

Tax Foreclosure Sale Held to Have Included Only Delinquent Taxpayers' Royalty Under Current Lease, Not Possibility of Reverter

Albert Jeffryes Griffiths owned an undivided 1/14 interest in both the surface and mineral estates of Section 5, Block 7, H&GN RR Co. Survey, Reeves County, Texas, one-third of which had been owned by his father, David W. Griffiths, as a life estate until his death in 1992. The mineral interest was subject to a 1/8-royalty oil and gas lease that contained the producing Meriwether No. 1 Well. In 1998 several local taxing districts filed suit for unpaid taxes against hundreds of defendants, including David W. "Griffith" and Jeffryes "Griffith." The suit resulted in foreclosure of the statutory tax lien against the defendants' interests, and the Griffiths interests were sold by the Reeves County Sheriff. After the Meriwether well stopped producing so that the lease it had held expired, Magnolia, LLC (Magnolia), which had succeeded to the interest purchased at the tax sale, executed a new oil and gas lease, later assigned to Diamondback E&P LLC (Diamondback). Ridgefield Permian, LLC (Ridgefield) meanwhile acquired a lease from Albert Jeffryes Griffiths, as trustee of a trust into which he had conveyed his interests in the land. Ridgefield and Griffiths, believing the Griffiths mineral interest had not been validly sold and conveyed in the sheriff's tax sale, sued Magnolia and Diamondback to quiet title to their asserted interest. Reversing a summary judgment for Magnolia and Diamondback, the court of appeals in *Ridgefield Permian, LLC v. Diamondback E&P LLC*, No. 08-9-00156-CV, 2021 WL 1783260 (Tex. App.—El Paso May 5, 2021, pet. filed), held that Griffiths, not Magnolia, owned the mineral interest.

The dispositive issue, according to the court, was whether Griffiths's possibility of reverter had been foreclosed upon and sold in the tax sale. The possibility of reverter, the court believed, could not possibly have been foreclosed upon because it was a non-taxable interest that remained attached to the surface estate, for which taxes were not delinquent. *Id.* at *9. Moreover, the foreclosure judgment had explicitly referred to the "Meriwether" lease and to a decimal interest that correlated to the Griffiths royalty interest under that lease, indicating to the court that only the Griffiths royalty under the then-current lease, now expired, had been sold for taxes. *Id.*

Editor's Note: The reporter's law firm represented Magnolia in this case.

Evidence of Operator's Willful Misconduct Held Sufficient Regarding Gas Plant Construction Cost Overruns but Not So for Drilling Operation

Apache Corp. v. Castex Offshore, Inc., No. 14-19-00605-CV, 2021 WL 1881213 (Tex. App.—Houston [14th Dist.] May 11, 2021, no pet. h.), decided the appeal of a trial court judgment, based on jury findings, against Apache Corporation (Apache), the operator under two operating agreements for properties in southern Louisiana, one for a natural gas processing plant and the other for an oil and gas lease, in favor of Castex Offshore, Inc. (Castex), a joint owner and non-operator.

Both agreements had provisions typical of operating agreements in the oil and gas industry, that the operator was required to conduct operations in a good and workmanlike manner but would not be responsible for losses sustained or liabilities incurred except those resulting from gross negligence or willful misconduct. Apache had sued Castex after Castex failed to pay its proportionate share of costs incurred in expanding the gas plant and in drilling a failed gas well. Castex counterclaimed, alleging that Apache's mismanagement had led to gross cost overruns in the construction of the gas plant and to irreversible reservoir damage in the case of the gas well. Damages were awarded Castex based on jury findings that Apache had not committed gross negligence but had engaged in willful misconduct in its management of both projects. The question for the court was whether the evidence was legally and factually sufficient to support the jury's finding of willful misconduct. *Id.* at *1.

Although the gas plant was located in Louisiana, the parties had incorporated a Texas choice of law provision into their agreement. Rejecting Apache's argument that the jury should have been instructed that "willful misconduct requires a subjective, intentional intent to cause harm," the court concluded that intentional injury is not required and applied what it considered the ordinary meaning of willful misconduct. *Id.* at *5. "[A] plaintiff can show that a defendant is liable for willful misconduct," said the court, "if the evidence [shows] that the defendant intentionally or deliberately engaged in improper behavior or mismanagement, without regard for the consequences . . . ." *Id.* Here the evidence was that Apache personnel in charge of the gas plant construction project, particularly in its early stages, were well aware that costs were vastly exceeding estimates and were consciously indifferent to them, deliberately ignoring procedures intended to control cost overruns. *Id.* at *6. That evidence sufficiently demonstrated willful misconduct, the court held. *Id.* at *7. Apache did not, according to the court, "articulate a clear argument for why the evidence is factually insufficient," instead proposing, in the court's characterization, "that the judgment must be reversed because 'no sane company would purposefully increase its own costs.'" *Id.* The standard, the court remarked, is whether the defendant engaged in misconduct without regard for the consequences, not whether the defendant sought to bring those consequences upon itself. *Id.*

The operating agreement for the drilling of the gas well had a Louisiana choice of law provision. *Id.* at *11. The court found that Louisiana law would apply the same standard as that of Texas, that to support a finding of willful misconduct, there must be some evidence that Apache intentionally or deliberately engaged in improper behavior or mismanagement without regard for the consequences. *Id.* The court concluded that the evidence did not support a finding of willful misconduct in the case of Apache's handling of the gas well. *Id.* at *15. Although "Castex could have overcome [the operating agreement's] exculpatory clause with legally sufficient evidence that Apache knew, but did not care, that it was mismanaging the drilling operation," it had not done so. *Id.* Instead, the evidence showed that while Apache knew of the repeated difficulties and failures it encountered during the drilling, it demonstrably made active efforts to address those. *Id.* at *14. Castex's pointing out that Apache had offered to sell its assets in the area after the failure of the drilling operation, in the court's view, did not provide more than a scintilla of evidence to support Castex's theory that Apache therefore did not care whether the well was successful. *Id.* at *15.

Damages for Lessee's Refusal to Pay Lease Extension Bonus Upheld

In a decision that seems questionable but also seems unlikely to have much precedential effect because of the unique facts, the court in *Apache Corp. v. Hill*, No. 10-19-00066-CV, 2021 WL 2252716 (Tex. App.—Waco May 28, 2021, pet. filed) (mem. op.), affirmed the trial court's award of damages in favor of the Hills, the lessors of oil and gas leases to Apache Corporation (Apache) on a 207.62-acre tract in Brazos County, Texas.

The leases contained the customary provision, in their paragraph 9, that the lessee may at any time deliver to the lessor a release of the lease and thereupon be relieved of all obligations thereafter arising under the lease. *Id.* at *1. They then provided in their paragraph 14 that "the following typewritten agreements and provisions shall supersede and govern the provisions in the printed form of this lease whenever such printed form is in conflict herewith" and, in a later paragraph 41, as follows:

> At Lessor's sole option, at the end of the primary term, if this lease is not being held in accordance with its terms and provisions, then Lessee shall lease the entire leased premises for an additional one (1) year term for an additional consideration of one thousand dollars ($1,000) per net mineral acre.

Id. at *2. Apache filed releases of the leases for record in the county clerk's office on April 28, 2016. Four days later the Hills notified Apache that they were exercising their option under paragraph 41 to require Apache to lease the land for an additional year for $1,000 per net acre. Apache declined to pay. *Id.*

The court of appeals agreed with the trial court that paragraphs 9 and 41 were so inconsistent that they could not subsist together; Apache's right to release the leases, said the court, was mutually exclusive of the lessors' right to extend the leases. *Id.* at *4. Paragraph 14, the court held, required that paragraph 41 supersede paragraph 9. *Id.*

Lease Held Expired on Cessation of Production

In *Gramrich Oil & Gas Corp. v. Meng*, No. 11-19-00022-CV, 2021 WL 2174339 (Tex. App.—Eastland May 28, 2021, no pet. h.) (mem. op.), the court affirmed the summary judgment granted William C. Meng, the lessor of a 1996 oil and gas lease covering three 40-acre tracts on his ranch in Throckmorton County, Texas, declaring that the lease had terminated when the wells ceased to produce and no operations were timely commenced to restore production.

The lease contained a customary habendum clause under which, after the end of its three-year primary term, it would remain in effect as long as oil or gas was produced, with an additional provision that each producing well would hold only a designated unit around it. Production from the wells in two of the three 40-acre producing units under the Meng lease ceased completely in September 2014, and the well in the third unit ceased to produce in June 2015. Meng allegedly told the lessees on October 28, 2015, that the lease had terminated, and he sent them a letter to that effect on January 11, 2016. *Id.* at *1.

The lessees sought to excuse their failure to reestablish production in order to perpetuate the lease on the basis of Meng's having repudiated the lease. The court acknowledged that a lessor's repudiation of a lease relieves the lessee of any obligation to conduct an operation that would maintain it in force pending a judicial resolution of the lease's validity but pointed out that "[a] repudiation occurring after the lease . . . had already terminated would have no legal significance." *Id.* at *8. The question for the court was whether the lease, at the time of Meng's statement to the lessees on October 28, 2015, that the lease had terminated, could have been extended by further operations under is cessation-of-production clause, which provided as follows:

> [1] If, after the expiration of the Primary Term, production shall cease on any unit, or units, Lessee shall have the right at any time within sixty (60) days from the first of such cessation to begin drilling or reworking operations in the effort to make any or all such units

> again produce oil or gas, in which event this Lease shall remain in force thereon so long as not more than sixty (60) days shall elapse between the completion of one such operation and the beginning of another, and if production of oil or gas is therefore resumed, so long thereafter as oil or gas is produced from the subject units. [2] However, in the event of said cessation, if sixty (60) consecutive days elapses during which no such operation is executed, this Lease shall terminate as to any unit designation on which there has been no production of oil or gas for said sixty (60) days, save and except 1/2 acre around the wellhead for a period of one year. . . . [4] Furthermore, yet not to include shut-in gas wells, if twelve (12) months shall elapse during which a unit does not produce in paying quantities, this Lease shall terminate on any such well.

Id. at *10.

The lessees maintained that the lease thus afforded them 60 days plus 12 months to restore production. The court disagreed based on the different purposes of the saving clause's separate sentences, providing for the perpetuation of the lease under different circumstances. The first two sentences, the court observed, provide for a termination of the lease after 60 days of total cessation of production during which the lessee takes no action toward drilling or reworking. *Id.* at *11. Conversely, the last sentence of the clause sets out the period of time during which production in paying quantities is to be measured and was inapplicable where, as here, production has ceased altogether. *Id.* Because production from all three wells had ceased, without the commencement of operations, more than 60 days before Meng advised the lessees that the lease had terminated, the lease had expired so that Meng's alleged repudiation was immaterial. *Id.* at *12.

Trial Court Did Not Abuse Its Discretion in Denying Lessee's Plea to the Jurisdiction and Motion to Abate to Add Necessary Parties

In re Occidental West Texas Overthrust, Inc., No. 08-20-00130-CV, 2021 WL 2070480 (Tex. App.—El Paso May 24, 2021, orig. proceeding), decided claims by Occidental West Texas Overthrust, Inc. and Oxy USA Inc. (collectively, Oxy) that the trial court abused its discretion in denying its pretrial motions in a case brought by Longfellow Ranch Partners, LP (Longfellow) asserting that 12 oil and gas leases held by Oxy had terminated.

Oxy argued in a plea to the jurisdiction that Longfellow lacked standing to assert claims arising out of leases under which the minerals were owned entirely by the State of Texas but that had been leased by Longfellow under the Relinquishment Act (granting the surface owner the right to lease the state's oil and gas interest and to receive one-half of the bonus, rentals, and royalty under any such lease). *Id.* at *1 (citing Tex. Nat. Res. Code § 52.190). Oxy argued in the alternative in a motion to abate that Longfellow's claims should be abated until all the owners of royalty interests, working interests, and overriding royalty interests were joined as parties. *Id.* at *3. The trial court denied those, and Oxy filed a petition in the court of appeals for a writ of mandamus.

The court of appeals first observed that "[m]andamus relief is only available when a trial court clearly abuses its discretion and there is no adequate remedy by appeal." *Id.* at *2. Concerning Oxy's plea to the jurisdiction, the court held that Oxy's assertion that proceeding with litigation would potentially result in a waste of time and money did not amount to a showing that the case involved any sort of extraordinary situation that would deprive it of an adequate remedy by appeal. *Id.* at *3. As to the motion to abate, the court acknowledged that all owners who claim interests that would be affected in a case involving lease termination must be joined; Oxy's merely providing its land manager's list of the names of such owners and their interests from its own internal records, without details such as citation to deed records or documents evidencing the chain of title, did not constitute sufficient objective record evidence to establish the nonparties' actual, claimed interest in the subject matter. *Id.* at *4. Thus, the court held, Oxy's evidence did not rise to the level of establishing that their joinder was mandatory as a matter of law, so that the trial court had not abused its discretion in denying Oxy's motion. *Id.* at *5.

Back-In Rights and Rights to Be Offered Reassignment Under Purchase and Sale Agreements Construed

Apollo Exploration, LLC v. Apache Corp., No. 11-19-00183-CV, 2021 WL 2371554 (Tex. App.—Eastland June 10, 2021, no pet. h.), involved separate but substantially identical purchase and sale agreements (PSAs) under which, in 2011, Apollo Exploration, LLC, Cogent Exploration, Ltd., Co., SellmoCo, LLC, and Gunn Oil Company (Gunn Oil), owners of 98% of the working interest under 109 oil and gas leases covering over 120,000 acres in the Texas Panhandle, including one on the Bivins Ranch for approximately 100,000 acres, sold 75% of their combined 98% working interest to Apache Corp. (Apache). Gunn Oil sold its remaining interest to Apache in 2014. The other three sellers sued Apache, alleging breaches of Sections 2.5 and 4.1 of each PSA. The trial court granted summary judgment to Apache on all of the sellers' claims and awarded it $4.8 million in attorneys' fees. *Id.* at *1. The court of appeals affirmed the summary judgment in part but reversed it in part and remanded the case to the trial court.

Section 2.5 afforded each of the sellers the option to "back-in" for up to 1/3 of the interests conveyed at a "Back-In Trigger" of 200% of "Project Payout," which was defined as the first day of the next calendar month following the point in time when Apache's revenue from production, less royalty and other burdens and severance taxes, reached the sum of the price paid to seller, the "Drilling Credit" (apparently defined elsewhere in the PSA), Apache's actual costs to explore, drill, and complete wells to the extent attributable to the leases assigned, and operating costs chargeable under a form of operating agreement attached to the agreement, as well as marketing and disposal costs. Additionally, the seller had the right at any time to pay Apache the remaining balance for the Back-In Trigger to receive the back-in interest as though the Back-In Trigger had occurred. Apache was required to provide the sellers annual written statements of the status of Project Payout and the Back-In Trigger. *Id.* at *1–2.

In its summary judgment motion for a declaration of how the Back-In Trigger should be calculated, Apache argued that "200% of Project Payout" meant that Apache must achieve a 2-to-1 return on its investment in the properties before the sellers could exercise their right to back in and that "Project Payout" included all of Apache's actual costs attributable to the properties, not just those approved by the sellers. *Id.* at *11. Pointing out that Section 2.5 defined "Project Payout" as a day, Apache alternatively argued that if it did not have the meaning Apache advanced, it was too indefinite to enforce. *Id.* The sellers countered with their interpretation that they were entitled to their back-in interest when Project Payout occurred (or when they chose the option to pay in advance), arguing that Apache requested the trial court to rewrite Section 2.5 to determine that the Back-In Trigger meant "200% of Apache's expenses" rather than "200% of Project Payout." *Id.*

The court noted that because the applicable form of operating agreement to which the parties had agreed in their PSAs afforded the sellers the right to timely except to costs charged by Apache, the operator, there was a genuine issue of material fact as to whether any of Apache's costs should be excluded from Project Payout and Back-In Trigger calculations. *Id.* at *12. The trial court had therefore erred in granting summary judgment to Apache to the extent that it declared that all costs were to be included. *Id.* The court further held that the fact that the sellers and Apache had differing interpretations of Section 2.5 did not establish that it was too indefinite to enforce. *Id.* That issue, though apparently a legal question, presumably remains for the trial court on remand.

In Section 4.1 of their PSAs, the parties had agreed that on or before November 1 of each year, Apache would provide the sellers a written budgeted drilling commitment for the upcoming calendar year, required to "balance exploration and development with lease maintenance and perpetuation." *Id.* at *5. It further required Apache to make a good-faith effort to follow that "Commitment" but that "if any Commitment contemplates or will result in the loss or release of one or more of the Leases (or parts thereof), then [Apache] shall concurrently offer all of [Apache's] interest in the affected Leases (or parts thereof) to Seller" and, upon the seller's acceptance, to assign those leases (or parts thereof) to the seller, in order to "provide Seller the option and ability to perpetuate all the Leases so offered . . . through a drilling program with one drilling rig . . . ." *Id.* The PSAs defined "Leases" as the oil, gas, and mineral leases specifically described in the PSA and others in which the seller owned an interest to the extent they covered lands in a specified area. *Id.*

The court affirmed Apache's summary judgment insofar as it construed Section 4.1 to require an offer of any leases expected to expire to apply only to leases that had been owned by the sellers at the time of the PSA and not, as the sellers argued, all other leases held by Apache covering the same acreage. *Id.* at *6. It reversed the judgment, however, insofar as it would exclude the interest in those leases that Apache had acquired from Gunn Oil, essentially agreeing with the sellers that "all" means "all." *Id.* at *10. It rejected Apache's argument that it would be impossible for it to offer all of its interest in any lease to the different sellers, so that Section 4.1 could not be enforced, remarking that, for example, any of the PSAs could be enforced as written if only one of the sellers accepted the offer or, if more than one seller accepted, Apache could assign to all of the sellers collectively. *Id.* at *8.

The court also rejected Apache's argument that the requirement that it offer the working interest originally owned by Gunn Oil would violate the rule against perpetuities because any asserted right to acquire that interest could vest outside the time period required by that rule. The sellers' interest in any lease did not automatically vest in them at any time, the court observed; instead, the PSA required Apache to offer a lease for which its annual drilling budget contemplated or resulted in its expiration. The sellers' rights were therefore, according to the court, very similar to a right of first refusal, held by Texas courts not to violate the rule against perpetuities because it does not constitute a restraint on alienation. *Id.* at *9.

A significant portion of the damages asserted by the sellers was attributable to the expiration of the lease on the Bivins Ranch as to a large amount of acreage that it covered. Because the value of that acreage was much less on November 1, 2015, than it had been on November 1, 2014, there was a material dispute between the parties whether that lease expired on December 31, 2015 (which meant, according to the sellers, that Apache should have offered the lease to them on November 1, 2014), or instead on January 1, 2016. *Id.* at *13. The lease was dated January 1, 2007, and provided for a primary term of three years, but a memorandum of the lease for recording purposes stated that the primary term became effective on January 1, 2007, and expired on December 31, 2009. *Id.* at *14. Successive amendments provided that the lessee could extend the lease for another year by meeting specified drilling commitments applicable to all of the Bivins Ranch acreage. *Id.* at *15. When Apache did not meet the required commitment for 2015, the lease expired, and Apache released it in a release made effective December 31, 2015. *Id.* Given that the memorandum stated the date of the expiration of the lease's primary term as December 31, 2009, that Apache's release appeared to state that it expired in 2015, and that an Apache landman had notified the sellers that it was possible the lease would expire "at the end of this year," there were genuine issues of material fact whether the lease expired in 2015 or 2016 so that summary judgment for Apache was improper to the extent that it construed the lease expiration date as January 1, 2016. *Id.* at *17.

Although the court remanded the case to the trial court to address the sellers' claims for Apache's alleged breach of contract, negligence, and fraud based on Apache's failure to provide needed information and on the loss of their right to reacquire leases that were lost or released, it affirmed the summary judgment for Apache insofar as it denied the sellers' claims for breach of express trust, breach of fiduciary duty, and misappropriation of fiduciary property. *Id.* at *19. In doing so it rejected the sellers' argument that the PSAs created an express trust by separating legal title from a beneficial interest in the "ability to perpetuate" the leases that would be lost by failure to develop, requiring Apache to preserve all of the leases so that the sellers would have the option and ability to perpetuate them. *Id.* at *18. Although the sellers had a contractual right that they could claim Apache violated, the court could discern no intent by the parties to separate legal title from any beneficial interest in the sellers or create an express trust for their benefit. *Id.*

The court devoted most of the rest of its opinion to the trial court's granting Apache's motion to exclude the sellers' three expert opinions on damages. The court had not abused its discretion in excluding one of those, the court held, largely because the expert's report insufficiently supported his valuations based on treatment of Apache's development of the property as a resource play versus a development play and failed clearly to show how his valuation reflected actual market value of the leases, *id.* at *20–25, and in excluding another because the expert's supplemental opinions were untimely, *id.* at *26–27. The trial court had erred in excluding the report of one of the experts, however, because it was grounded in analysis of comparable transactions and, most importantly, that it appeared the trial court's rejection of the expert's testimony was because it had concluded that his damages calculation must be based on the value of the expired Bivins Ranch lease as of November 1, 2015, rather than, as calculated by the damages expert, as of November 1, 2014. *Id.* at *25–26.

Anti-Washout Provision Violative of Rule Against Perpetuities Held Capable of Reformation

The Yowells owned an overriding royalty interest in a 1986 oil and gas lease originally reserved in an instrument that purported to "attach the interest to an extension, renewal or new lease" obtained by the assignee should the burdened lease expire. The Texas Supreme Court held in *Yowell v. Granite Operating Co.*, 620 S.W.3d 335 (Tex. 2020), *see* Vol. XXXVII, No. 3 (2020) of this *Newsletter*, that the provision violated the rule against perpetuities insofar as it applied to a new lease because it was contingent on events that may not happen at all, let alone within lives in being plus 21 years as required by the rule. The supreme court remanded the case to the court of appeals to consider whether the Yowell interest might be capable of reformation under Tex. Prop. Code § 5.043, which provides the following mandate: "Within the limits of the rule against perpetuities, a court shall reform or construe an interest in real or personal property that violates the rule to effect the ascertainable general intent of the creator of the interest."

On remand, the Yowells argued that bringing their interest within the rule was simple, and the court in *Yowell v. Granite Operating Co.*, No. 07-17-00112-CV, 2021 WL 2639921 (Tex. App.—Amarillo June 25, 2021, no pet. h.), agreed. The interest could be brought within the limits of the rule by reforming it to limit the time period in which it might vest to no longer than 21 years after the death of any natural person who was alive at the time the overriding royalty was created, the court remarked, for example that of the assignor who originally reserved the interest. *Id.* at *2. Because the record provided little guidance as to the intent of the creator, it remanded the case to the trial court to develop the evidence of the intent and to reform the instrument to reflect it. *Id.* at *3. In doing so it rejected arguments that the Yowells were barred by limitations, pointing out that the supreme court had stated that the reformation contemplated by section 5.043 was not subject to limitations. *Id.* at *4.

Joint Development Agreement's AMI Provision Held Not to Apply to Saltwater Disposal Pipelines Built by Operator

In *Big Hatchet, LLC v. Monadnock Resources, LLC*, No. 07-19-00261-CV, 2021 WL 2763108 (Tex. App.—Amarillo July 1, 2021, no pet. h.) (mem. op.), the court construed a joint development agreement between Monadnock Resources, LLC (Monadnock), which owned a large majority working interest in the oil and gas properties the parties desired to explore and develop and served as operator, and Big Hatchet, LLC (Big Hatchet), the owner of a non-operating minority interest. The agreement included the following Section 6.1:

> In the event on or before three (3) years after the Effective Date any Party or its Affiliate, directly or indirectly, acquires or seeks to acquire any AMI Interests that consist of or include rights or interests within the AMI Area, from any third other than a Party hereto, the acquiring Party ("Acquiring Party") shall promptly provide written notice to the other Party ("Rights Party"), offering the Rights Party an opportunity to purchase the Rights Party AMI Share (defined [therein]) of such AMI Interest . . . .

Id. at *1 (alteration in original). Section 1.1 of the agreement defined "AMI Interest" to include any infrastructure related to the exploration, operation, or development of oil and gas properties. *Id.* at *2.

After execution of the joint development agreement, Monadnock acquired rights-of-way and contracted for the construction of two saltwater disposal pipelines within the "AMI Area" defined in the agreement. It refused to offer Big Hatchet the opportunity to participate in ownership of the pipelines in the manner prescribed by the agreement, and Big Hatchet sued, asserting that Monadnock had breached Section 6.1. *Id.* The trial court granted summary judgment to Monadnock, and the court of appeals affirmed.

Big Hatchet contended that because Monadnock acquired the component parts of the pipelines (specifically the rights-of-way) from third parties, it was obligated to offer Big Hatchet the right to participate in the pipelines. *Id.* at *3. Monadnock countered that the joint development agreement was never intended to cover its unilateral operations in the development of the properties. *Id.* A plain reading of the agreement, the court concluded, supported Monadnock. *Id.* "A pipeline right-of-way," the court reasoned, "in and of itself, is of little use and benefit to the exploration, operation, or development of the hydrocarbon minerals without the accompanying use of the pipeline itself" and thus, as an individual component, did not meet the definition of "infrastructure." *Id.* The completed project, it continued, was properly considered "infrastructure" but was not "acquired" from a third party and so was not subject to Section 6.1. *Id.*

Deed Construed Not to Have Reserved Preexisting and Reversionary Royalty Interests

The court in *Pauler v. M & L Minerals, LP*, No. 04-20-00302-CV, 2021 WL 2814906 (Tex. App.—San Antonio July 7, 2021, no pet. h.) (mem. op.), construed a 1977 deed from Susan Janysek and eight of her nine children to her ninth child, Vincent J. Janysek, and his wife, Leona B. Janysek, conveying a 197-acre tract of land in Karnes County, Texas.

Before the 1977 deed, Susan Janysek and her husband had, in 1958 and 1959, conveyed "Term Royalty Interests" of 1/4 and 1/8 of the royalty on production from the land, each for a term of 10 years and as long thereafter as oil or gas was produced. Those interests had not expired at the time of the 1977 deed but subsequently did so. In addition, they had conveyed a 1/24 interest in the royalty to each of their nine children (1/24 Royalty Interests). *Id.* at *1. The 1977 deed, after conveying the land, stated as follows: "This conveyance is subject, however, to all mineral conveyances, mineral reservations, oil, gas and other mineral leases, royalty conveyances or reservations, easements, ordinances and rights-of-way of record in the office of the County Clerk of Karnes County, Texas." *Id.* In its next paragraph the deed expressly reserved a nonparticipating royalty interest:

> In addition to the above exceptions, there is reserved and excepted unto SUSAN JANYSEK, an undivided one-fourth (1/4) interest in and to all royalty paid on the production or mining of oil, gas and any and all other minerals . . . . Such royalty interest is for the life of SUSAN JANYSEK, and after her death, such royalty interest shall revert to [Susan's nine children, identified by name].

Id. (alteration in original).

After an oil and gas lessee in 2018 interpreted the deed to have conveyed the Term Royalty Interests (or, describing the circumstances more accurately, the royalty that reverted to the grantors, or their successors and assigns, when those interests expired) and the grantors' 1/24 Royalty Interests, leaving the grantors only the 1/4 of the royalty expressly reserved, the successors to the grantors' interests (referred to in the opinion as the "Moczygembas") sued the successors to the grantees' interest (the Janyseks) for a declaratory judgment that the 1977 deed did not convey either the Term Royalty Interests or the 1/24 Royalty Interests. *Id.* at *2. The trial court granted summary judgment for the Moczygembas, but the court of appeals reversed and rendered judgment for the Janyseks, holding that the grantors had conveyed all of their interests except the specifically mentioned reservation. *Id.* at *6.

After reciting the rules of construction that an exception or reservation will not be implied when a deed does not otherwise express an intention to limit the conveyance and that deeds are construed to confer the greatest estate the terms of the instrument will allow, *id.* at *4, the court observed that the 1977 deed did not state with any certainty that the disputed royalties were excepted or reserved, *id.* at *5. Nor did the "subject to" clause create uncertainty as to the extent of the grant: A plain reading of the "subject to" clauses (that quoted above and another in the deed's habendum clause) was that they served their principal function, to protect the grantor against a claim for breach of its warranty of title when some mineral interest is outstanding. *Id.* And contrary to the Moczygembas' argument, the deed's reference "to the above exceptions" in introducing the express reservation of 1/4 of the royalty did not, in the court's view, display a clear intent to reserve or except the disputed interests. *Id.*

Assignment Held Depth-Limited Where Lease Assigned Only Insofar as It Covered Described Proration Units

The court in *Posse Energy, Ltd. v. Parsley Energy, LP*, No. 08-20-00061-CV, 2021 WL 3140054 (Tex. App.—El Paso July 26, 2021, no pet. h.), construed a 1992 assignment from Westland Oil Development Corporation (Westland) to PetroTide, Ltd. (PetroTide), predecessor by merger to Posse Energy, Ltd. (Posse). One of the oil and gas leases included in the assignment was the "Morgan" lease covering land in Upton County, Texas. At the time Westland owned 24.2333% of the leasehold under the Morgan lease, insofar as it covered depths between 7,194 feet and 8,900 feet below the surface (the "Shallow Rights") in five quarter-sections described in the assignment, and it owned 72.7% of the leasehold in deeper depths in the same land. Parsley Energy, LP (Parsley) and Pacer Energy, Ltd. (Pacer) had succeeded to the Westland interests, and the issue in the lawsuit filed by Posse against Parsley and Pacer was whether the 1992 assignment had included depths below 8,900 feet (the "Deep Rights"). *Id.* at *1–2. Affirming the trial court's summary judgment, the court of appeals held that it had not.

The assignment had been made pursuant and subject to an acquisition agreement between Westland and PetroTide under which PetroTide would cancel certain indebtedness owed by Westland in exchange for Westland's assignment of its properties pledged under deeds of trust securing the indebtedness, plus additional properties set forth in exhibits to the agreement. One of those exhibits described the Morgan lease, "INSOFAR AND ONLY INSOFAR as the lease covers the proration units for the following wells," which was followed by a tabular listing of five wells and, for each, a quarter-section land description and the "Interest Assigned" of 24.2333% working interest and 21.20412% net revenue interest. *Id.* at *11. The assignment conveyed to PetroTide the leases and properties "described in Exhibit A" attached to the assignment, which Exhibit A contained descriptions identical to those in the acquisition agreement, as well as "all other rights, titles and interests" of Westland in the lands and leases described. *Id.* at *12.

Posse's position was that because the assignment conveyed "all right, title and interest" in the Morgan lease, without any reference to a depth limitation, and "all means all," the assignment included all depths in which Westland owned an interest. *Id.* at *6. Parsley and Pacer countered that the assignment had been intended to include only properties that had been pledged as collateral under the deeds of trust securing the indebtedness being canceled, which clearly had been limited to depths above 8,900 feet, and that this was discernable when the acquisition agreement, which referred to the security documentation, was read and considered together with the assignment, and that in any event, the description in the assignment did not include the Deep Rights by its own terms. *Id.* at *7–8.

The court agreed with Parsley and Pacer, declaring that the contractual language was unambiguous and that the parties intended to limit the conveyance to Shallow Rights. *Id.* at *8. The description of the Morgan lease in the assignment and in the acquisition agreement, the court pointed out, was limited to the "proration units" assigned to the listed wells. *Id.* at *9. The only production occurring in the described quarter-sections was from the Shallow Depths. *Id.* at *11. Accordingly, declared the court, the proration unit, having been assigned to each well for the regulatory purpose of allocating allowable production, "could not extend into an area where production was not occurring, such as the area below 8,900 feet . . . ." *Id.* The assignment therefore could not possibly have covered the Deep Rights. The court's interpretation was supported, it believed, by the listing of Westland's specific interests consistently with its interests in the Shallow Rights without mention of its different, larger interest in the Deep Rights. *Id.* The court also agreed with Parsley and Pacer that the assignment and acquisition agreement must be read alongside and harmonized with the underlying security documents that were being settled, which it believed confirmed the parties' intention to limit the assignment's scope. *Id.* at *12.

Editor's Note: The reporter's law firm represented Posse in this appeal.

Operator Improperly Withheld "Prospect Development" Costs from Non-Operator's Revenues

BBX Operating, LLC v. American Fluorite, Inc., No. 09-19-00278-CV, 2021 WL 3196514 (Tex. App.—Beaumont July 29, 2021, no pet. h.) (mem. op.), decided a dispute between BBX Operating, LLC (BBX), the operator under two joint development agreements (JDAs), and three related non-operators, American Fluorite, Inc., GeoSouthern Energy Partners, LP, and GeoSouthern Energy Corp. (collectively, GeoSouthern), for the acquisition and development of oil and gas prospects in East Texas.

One of the agreements, the "Neches II" JDA, provided that any party to the agreement could acquire oil and gas leases within the area embraced by the agreement (an area of mutual interest (AMI)), and the other, the "Make My Day" JDA, that only BBX would acquire leases. Both JDAs required the party acquiring a lease in the agreement's AMI to notify the other and offer it the right to participate in the acquisition and provided that failure to elect to purchase and pay for the recipient's share of the acquisition would constitute relinquishment of the right to participate in it. The agreements also provided for the proposal of the drilling of wells. If a party elected to participate in a proposed well, operations would be governed by an agreed form of operating agreement under which, as is customary, the operator may retain a party's production proceeds if it fails to pay its share of costs and expenses. *Id.* at *1–2.

After acquiring leases in which GeoSouthern had apparently participated, BBX sent "cash call" letters to non-operators for costs of brokers' fees, title examination, title curative, and other expenses it termed "prospect development" costs, asserting that the JDAs gave it authority to collect those. GeoSouthern objected that the JDAs did not permit BBX to recover those costs in the absence of a well proposal. When GeoSouthern refused to pay, BBX began withholding GeoSouthern production revenues. GeoSouthern filed suit seeking, among other things, a declaratory judgment that the JDAs did not authorize BBX to withhold revenues to offset costs and that GeoSouthern did not owe any pre-development costs for wells not yet proposed. *Id.*

at *3. The trial court granted summary judgment for GeoSouthern, and the court of appeals affirmed.

The court agreed with GeoSouthern that the JDAs did not authorize BBX to offset its revenues against costs for unproposed wells and that it did not owe those costs for a well in which it ultimately elected not to participate. *Id.* at *15. Although the court's reasoning is not altogether clear, it evidently concluded that the kinds of costs BBX sought from GeoSouthern in its cash calls were recoverable only after an operating agreement was in place, which would only occur after a non-operator elected to participate in a proposed well. It rejected BBX's argument that prospect development costs were not addressed in the JDAs and that there was a fact issue whether it was entitled to recoupment of those based on custom and usage and the fact that other working interest owners paid them without objection. *Id.* at *16.

The court's opinion largely dealt with whether or not the summary judgment evidence supported the damages awarded GeoSouthern for unpaid revenues. The court held that it did, pointing out that the trial court could take into account not only affidavit testimony submitted by GeoSouthern, alleged to be objectionable because conclusory, but also that of BBX that supported the calculations. In a companion case, *BBX Operating, LLC v. American Fluorite, Inc.*, No. 09-19-00279-CV, 2021 WL 3196513 (Tex. App.—Beaumont July 29, 2021, no pet. h.) (mem. op.), the court also upheld a writ of garnishment against BBX for GeoSouthern's unpaid revenues, holding that GeoSouthern's land manager's affidavit contained sufficient detail to meet the statutory requirements for such a writ. *Id.* at *5.

WEST VIRGINIA – MINING

Andrew S. Graham
– Reporter –

West Virginia Supreme Court of Appeals Holds That Right of First Refusal Does Not Implicate Stranger to Deed Rule but Mulls Outright Abolition of That Rule

In *Klein v. McCullough*, 858 S.E.2d 909 (W. Va. 2021), the West Virginia Supreme Court of Appeals held that "a clause in a deed giving a stranger a right of first refusal is neither a reservation nor an exception to the granting clause of the deed," and therefore, such a clause "may not be considered void under the [common law] 'stranger to the deed' rule." *Id.* at 915.

In 1995, Julia McCullough conveyed a tract of land in Tyler County, West Virginia, including the oil and gas rights, by deed to her son Benjamin F. McCullough. The deed contained the following provision: "This conveyance is made subject to the provision that upon the subsequent conveyance, sale or devise of the said property, the said Benjamin F. McCullough, his heirs or assigns, shall offer a first right of refusal to . . . Lanna L. Klein." *Id.* at 912. Benjamin was Lanna's brother; he died in 2010 and devised his entire estate, including the subject property, to his wife Darlene McCullough. Without offering the subject property to Lanna, Darlene conveyed it to two third parties who, in turn, leased the oil and gas. *Id.*

Lanna sued Darlene to enforce the right-of-first-refusal provision in the 1995 deed. Darlene moved to dismiss the case because Lanna was neither the grantor nor the grantee in the 1995 deed, which made Lanna a "stranger" to the 1995 deed. West Virginia recognizes the common law rule that "a 'reservation or an exception in favor of a stranger to a conveyance does not serve to recognize or confirm a right'" and a "reservation to a stranger to the instrument is void for all purposes." *Id.* at 912 (quoting *Erwin v. Bethlehem Steel Corp.*, Syl. Pt. 3, 62 S.E.2d 337 (W. Va. 1950); *Beckley Nat'l Exch. Bank v. Lilly*, 182 S.E. 767, 773 (W. Va. 1935)). Lanna admitted that she was a stranger to the deed and the Circuit Court of Tyler County dismissed Lanna's complaint because "the right of first refusal in favor of Lanna Klein in the [1995] deed is void, inoperative and cannot be enforced by [Lanna]." *Id.* at 913. Lanna appealed.

The West Virginia Supreme Court of Appeals reversed the circuit court's decision and held that the common law rule did not apply to Lanna's right of first refusal because "a right of first refusal is neither a reservation nor an exception to the granting clause of the deed." *Id.* at 915. The court also signaled its willingness to consider the outright abolition of the common law rule even though the court ultimately decided that it could not do so in this case because the issue was not raised before the circuit court. Instead, Lanna's counsel presented the argument for the first time during oral argument before the court. Nevertheless, the majority opinion admitted that, in another case, it "might have been impelled to abolish the 'stranger to the deed' rule." *Id.* at 916. The court noted that courts in 10 states, including Alaska, California, Colorado, Kentucky, Missouri, Montana, North Dakota, Oregon, Tennessee, and Wyoming, have either abolished the rule, or refused to adopt it, while two states, Rhode Island and South Dakota, have abolished the rule by statute. *Id.* at 916 n.7.

Justices Armstead and Wooton concurred in the court's judgment, writing separately to express their disagreement "with the majority's suggestion that this Court may have been impelled to abolish the 'stranger to a deed' rule if the parties had properly raised this argument." *Id.* at 917 (Armstead, J., concurring).

WYOMING – OIL & GAS

Jamie L. Jost & Amy Mowry
– Reporters –

Wyoming's Eminent Domain Statute Requires Sufficient Evidence of Mineral Ownership to Justify Access to Property

In *EME Wyoming, LLC v. BRW East, LLC*, 2021 WY 64, 486 P.3d 980, an appeal from the District Court of Goshen County, the Wyoming Supreme Court revisited the Wyoming Eminent Domain Act (Act), Wyo. Stat. Ann. §§ 1-26-501 to -817, concluding that a party seeking access under the Act must show that it owns development rights and that the data it seeks to collect relates to that interest and will be used for its development.

EME Wyoming, LLC (EME) is an oil and gas company that claimed a right under the Act to access roughly 52,000 acres of land located primarily in Goshen County, owned by BRW East, LLC, BRW West, LLC, Indian Meadows East, LLC, Indian Meadows West, LLC, and Warren Bartlett (collectively, BRW), ostensibly for the purpose of gathering data to evaluate whether the property was suitable for condemnation under the Act. BRW objected, claiming EME only sought access to gather data for the purpose of filing applications for permits to drill (APDs) and to beat out competitors under Wyoming's "first to file" regulatory scheme for operatorship determination. *See EME*, 2021 WY 64, ¶ 1 ("In the development of oil and gas resources, Wyoming is a first-to-file state. This means that when two or more entities have the right to produce oil and gas in an area, the Wyoming Oil and Gas Conservation Commission (WOGCC) will grant sole operating rights to the first entity to collect the necessary information and file an [APD].” (citing *Devon Energy Prod. Co. v. Grayson Mill Operating, LLC*, 2020 WY 28, 458 P.3d 1201)). EME sued to gain access under the Act. *Id.* ¶ 2.

The district court allowed EME access to BRW’s acreage but prohibited EME from using any survey information it collected in its APD filings with the WOGCC. BRW appealed the court’s allowance of access, and EME appealed the court’s prohibition on its use of gathered data for APD filings. *Id.* ¶¶ 3–4.

On appeal, the Wyoming Supreme Court narrowed the issue to whether EME established that it was a “condemnor” as that term is defined under the Act, thus allowing EME access to BRW’s acreage. *Id.* ¶ 5. In the context of the Act, the court considered both the constitutional and statutory provisions as governed by Wyo. R. Civ. P. 71.1, “including notice, the plaintiff’s right to make the appropriation, plaintiff’s inability to agree with the owner, the necessity for the appropriation, and the regularity of the proceedings.” *Id.* ¶ 16 (quoting *EOG Res., Inc. v. Floyd C. Reno & Sons, Inc.*, 2020 WY 95, ¶ 16, 468 P.3d 667). To the extent the district court’s judgment can be upheld with sufficient evidence, it will be upheld, and the court will “look only to the evidence submitted by the prevailing party and give to it every favorable inference which may be drawn therefrom, without considering any contrary evidence.” *Id.* (quoting *EOG*, 2020 WY 95, ¶ 16).

In considering the evidence presented, the court noted the stated purpose of the Act: to allow condemnors a right of entry to “make surveys, examinations, photographs, tests, soundings, borings and samplings, or engage in other activities *for the purpose of* appraising the property or *determining whether it is suitable and within the power of the condemnor to condemn* . . . .” *Id.* ¶ 19 (quoting Wyo. Stat. Ann. § 1-26-506(a)). Given the evidence presented by EME, the court concluded that “EME made no showing of mineral ownership that would so qualify it,” and thus the court did not address “the question of whether an oil and gas company’s right of condemnation is limited to ways of necessity or otherwise define the parameters of that right.” *Id.* ¶ 22.

In reaching its conclusion, the court strictly interpreted the Act in favor of landowners, “so that no person will be deprived of the use and enjoyment of his property except by a valid exercise of the power.” *Id.* ¶ 23 (quoting *Coronado Oil Co. v. Grieves*, 603 P.2d 406, 410 (Wyo. 1979)). The court also relied on its usual rules of statutory interpretation, where the court’s goal “is to give effect to the intent of the legislature . . . based primarily on the plain and ordinary meaning of the words used in the statute.” *Id.* (internal quotation marks omitted) (quoting *Wyo. Jet Ctr., LLC v. Jackson Hole Airport Bd.*, 2019 WY 6, ¶ 12, 432 P.3d 910). The court disagreed with EME’s “overly broad” contention that it was “a person empowered to condemn” under the Act, *id.* ¶ 24 (quoting Wyo. Stat. Ann. § 1-26-502(a)(iii)), simply “because it is an oil and gas company and the Act extends the right of eminent domain to oil and gas companies,” *id.* Again, eminent domain statutes are to be interpreted narrowly, *id.* ¶ 29, and as the court explained, “[o]ur decisions preceding the legislature’s 1981 enactment of the Eminent Domain Act, and those since its enactment, have plainly recognized that the right to condemn for mineral development springs from mineral ownership,” *id.* ¶ 28.

Furthermore, a reading in line with EME’s argument would fail to harmonize the Act with Wyoming’s Split Estate Act, Wyo. Stat. Ann. §§ 30-5-401 to -410, “through which [Wyoming’s legislature] codified an oil and gas operator’s access to surface lands and placed conditions on that access.” *EME*, 2021 WY 64, ¶ 30. As the court stated, “[w]e can think of no reason the legislature would place conditions on a mineral owner’s access to surface under the Split Estate Act while at the same time allowing any entity, regardless of mineral ownership, access under the Eminent Domain Act.” *Id.* The court concluded, instead, “that the legislature intended, consistent with our holding in *Coronado*, that only those entities with landlocked mineral ownership would have the power to condemn under the Eminent Domain Act.” *Id.* ¶ 31.

The court reversed the district court’s order granting EME access to BRW’s property because “EME did not make the required showing for access,” *id.* ¶ 34, and further found that “[b]ecause EME should not have been permitted access to the property, [any related] data is not lawfully in its possession, and it may not use it for any purpose,” *id.* ¶ 35. The court remanded the case for clarification and an appropriate limitation on any use of collected data by EME. *Id.* ¶ 36.

DEQ’s Proposed Amendments to Regulations for Class VI Injection Wells

In response to recent legislative and regulatory changes related to oil and gas conservation, the Wyoming Department of Environmental Quality (DEQ) proposed amendments to the state’s water quality rules and regulations pertaining to Class VI injection wells and facilities within Wyoming’s underground injection control program. *See* Wyo. Rules & Regs. 020.0011.24. The changes are intended to conform the DEQ rules with current Wyoming Oil and Gas Conservation Commission regulations, to add certain definitions pursuant to the U.S. Environmental Protection Agency’s (EPA) primacy review, and to both clarify the public liability insurance requirements and mitigate risk to the state, among other purposes.

Definitional changes include, among others, the following adjustments and additions:

- The definition of “abandoned well,” or “a well whose use has been permanently discontinued or that is in a state of disrepair such that it cannot be used for its intended purpose or for observation purposes,” now clarifies that “[t]emporary or intermittent cessation of injection operations is not abandonment.”
- The definition of “Class VI well” is expanded to mean “a well that is used for injecting a carbon dioxide stream for geologic sequestration that: (i) Is not experimental in nature and injects a carbon dioxide stream for geologic sequestration, beneath the lowermost formation containing an underground source of drinking water; (ii) Has been granted a waiver of the injection depth requirements pursuant to requirements of Section 15 of this Chapter; or (iii) Has received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to Section 16 of this Chapter.”
- The definition of “Indian lands” and “Indian country” is added and means: “(i) All land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation; (ii) All dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state; and (iii) All Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.”

Numerous significant changes appear elsewhere within the proposed amendments to address the following additional concerns:

- The addition of phrases to existing statements or lists to meet federal stringency requirements for primacy, as requested by the EPA.
- The addition of an affidavit filing requirement for consistency with Wyo. Stat. Ann. § 35-11-313(f)(vi)(G).
- The removal of requirements to allow self-bonding as an allowed instrument for financial assurance due to little demand to use the instrument, along with the previous regulations' requirement for substantial revision to be consistent with authorizing statutes and other DEQ regulations.
- Additional revisions to the financial assurance requirements for consistency with other DEQ and banking rules and statutes related to financial assurance.
- The removal of passages from the rule that are restatements of the Wyoming Statutes.
- The addition of section 28 to meet Wyoming Administrative Procedure Act incorporation by reference requirements.
- Reference to specific American Petroleum Institute and ASTM International standards that are stated in a manner that is both consistent with federal requirements and the Wyoming Administrative Procedure Act.
- Corrections to formatting and style inconsistencies and errors.
- Reorganization of the whole chapter to clarify and to improve the navigability of the requirements for permit applicants and permittees.

CANADA – OIL & GAS

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– Reporters –

Introduction of Competitive Carbon Sequestration Bid Process

On May 12, 2021, the Alberta provincial government announced that it will now be granting rights for carbon sequestration projects, also known as carbon capture utilization and storage (CCUS), through a competitive process. *See* Gov't of Alberta, Information Letter 2021-19, "Carbon Sequestration Tenure Management" (May 12, 2021). CCUS methods may take a variety of forms, but generally involve capturing a large volume of carbon dioxide from the atmosphere, transporting it, and injecting it into the ground to be permanently stored.

Carbon Sequestration in Alberta

CCUS is considered an integral technology for reducing the effects of global greenhouse gas emissions. CCUS has also gained recent attention as an integral component in the production of "blue hydrogen," a method of producing hydrogen from hydrocarbons through steam methane reforming. For hydrogen to be considered "blue," the carbon dioxide resulting from this process of creating hydrogen from hydrocarbons must be sequestered. The usual method for this involves underground storage using CCUS.

In Alberta, the 582-square kilometer area known as the Industrial Heartland is slated to become Canada's first hydrogen node for the production and use of blue hydrogen. The Industrial Heartland enjoys well-developed energy infrastructure, as well as geology favorable to existing CCUS methods. Further, hydrogen production is a part of the Alberta government's Natural Gas Vision and Strategy, which was announced in 2020 and calls for the province to become a global supplier of hydrogen. *See* Vol. XXXVII, No. 4 (2020) of this *Newsletter*. The province is currently home to two commercial-scale carbon capture projects, the Quest Project and the Alberta Carbon Trunk Line, which together capture and inject roughly 2.75 million tons of carbon dioxide annually. Given this context, a competitive process to grant carbon sequestration rights is the logical next step in the process.

In the past, carbon sequestration rights in Alberta have been awarded on application, but do not follow any overarching strategy. Following amendment of the *Oil and Gas Conservation Act*, R.S.A. 2000, c O-6, by the *Carbon Capture and Storage Statutes Amendment Act, 2010*, S.A. 2010, c 14, the Alberta Energy Regulator (AER) has had the power to approve or deny CCUS projects on the basis of the potential impacts to the recovery or conservation of oil or gas, or to an existing use of the underground storage formations for oil and gas.

Alberta's new process will introduce a new competitive as well as cooperative aspect to the province's CCUS regime by establishing applicants as hub operators. This follows the approach being taken in the United Kingdom, which aims to establish CCUS clusters where emitters can share infrastructure.

Impetus

The AER, the executive body responsible for the development of energy and mineral resources in Alberta, has received a large number of inquiries about carbon sequestration tenure for CCUS projects without associated oil or gas recovery. Enhanced hydrocarbon recovery using carbon dioxide is an established process in the province and one the regulator is familiar with. However, standalone CCUS is comparatively new. As such, the Alberta government recognized the need to establish an improved process to manage carbon sequestration tenure going forward.

Overview of the Announcement

The announcement from the Alberta government outlines a general framework for the competitive process which will govern the issuance of carbon sequestration rights. The overarching goal of the competitive process is to encourage the development of strategically located carbon storage "hubs," instead of limited or one-off sequestration projects that do not have the capability of supporting CCUS for multiple industrial facilities. As the Industrial Heartland is home to many such facilities, this incentivizes a strategic approach to CCUS development in the area.

The announcement applies to dedicated geologic carbon dioxide storage hubs only and does not apply to projects such as enhanced oil or gas recovery that inject carbon dioxide for improved hydrocarbon recovery. As noted above, the AER is familiar with this process and such projects will continue under the existing mineral rights tenure system.

Given that carbon sequestration tenure can require large areas and that CCUS projects may impact adjacent resource development activities, the Alberta government aims to use the competitive selection process to ensure both efficient pore space management and strong risk management. This, in part, is meant to address concerns that allowing unregulated CCUS development would risk unnecessary perforations and development in storage zones, limiting their capacity.

While specific guidelines for the competitive process are still under development, the announcement signals that the bar will be set high for potential hub operator proponents. Items that will be taken into consideration include:

- a proponent's technical, financial, and operational capabilities;
- location and geology of the proposed injection site; and
- existence or proximity of a system for transporting carbon to the site.

Fortunately, given Alberta's history with energy infrastructure development and related capabilities, operators with these capabilities and access likely already exist in the province.

In addition to meeting the above-noted requirements, hub operators will be required to provide CCUS services on an open access basis at fair service rates, and will be required to manage carbon offsets or future credits on behalf those participants taking advantage of the hub's services.

While the details of the competitive process are under development, once the process is completed, the Alberta government plans to enter into further discussions with successful project proponents to discuss access to CCUS hubs, service rates, and impacts on carbon offsets and carbon credits.

Next Steps

For now, the Alberta government is not contemplating changes to the existing legislation or regulations. Further details on the competitive framework for awarding carbon sequestration tenure are expected to be released this year.

The Alberta government encourages project proponents to consider submitting CCUS proposals once the new process is released. It is expected that such proposals should outline the transportation of captured carbon dioxide to the project sites and identify approximate geographic and geologic locations for carbon dioxide injection and storage.

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Volume XXXVIII, Number 3, 2021
ISSN 2768-7821