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Newsletter

Volume XXXVIII, Number 2, 2021

FEDERAL — MINING

Wells Parker, Benjamin Machlis & Kayla Weiser-Burton
– Reporters –
John Bernetich & Dale Ratliff
– Guest Reporters –

Interior Department Rescinds 2017 Order That Revoked the Moratorium on New Federal Coal Leasing

In one of her first acts following Senate confirmation, Secretary of the Interior Deb Haaland rescinded a 2017 secretarial order issued by Secretary Ryan Zinke that revoked a moratorium on new coal leasing issued under the Obama administration. *See* Secretarial Order No. 3398 (Apr. 16, 2021). Secretary Haaland's order establishes a U.S. Department of the Interior (Interior) policy to "listen to the science; to address societal inequities and create opportunities for the American people; to conserve and restore our land, water, and wildlife; to reduce greenhouse gas emissions; to create jobs through a growing clean energy economy; and to bolster resilience to the impacts of climate change." *Id.* § 3. Consequently, Secretary Haaland revoked a series of secretarial orders deemed inconsistent with this policy, including the 2017 order issued by Secretary Zinke. *Id.* § 4. Secretary Haaland's order also directs Interior to review and revise, as applicable, all policies and instructions implementing the newly-revoked orders. *Id.* § 5.

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FEDERAL — OIL & GAS

Kathleen C. Schroder & Kelsey Johnson
– Reporters –

Secretarial Order No. 3395 Expires but Interior Retains Assistant Secretary Review of Certain Oil and Gas Authorizations

On January 20, 2021, the Acting Secretary of the Interior issued Secretarial Order No. 3395, which revoked for 60 days the authority of the bureaus within the U.S. Department of the Interior to "issue any onshore or offshore fossil fuel authorization," including approvals of applications for permits to drill (APDs) and issuance, suspensions, and extensions of oil and gas leases. *See* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. Secretarial Order No. 3395 instead vested authority for these authorizations with acting officials within the Department at the Assistant Secretary level or higher.

Secretarial Order No. 3395 expired without being renewed. On March 19, 2021, however, Laura Daniel-Davis, the Principal Deputy Assistant Secretary, Land and Minerals Management, issued a memorandum that identified certain actions that the Assistant Secretary for Land and Minerals Management must review. *See* Memorandum from Laura Daniel-Davis, Principal Deputy Assistant Secretary, Land and Minerals Management, to Bureau Directors (Mar. 19, 2021). These actions include:

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RENEWABLE ENERGY

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

Congress Extends Tax Credits for Solar and Wind Investment

Congress first approved tax credits for renewable energy projects as part of the Energy Tax Act of 1978, Pub. L. No. 95-618, § 301, 92 Stat. 3174. The Energy Tax Act provided tax incentives for both the production and the conservation of energy. *Id.* Almost three decades later, Congress established an investment tax credit (ITC) of 30% for solar projects as part of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594. Under section 48 of the Internal Revenue Code, when a commercial solar photovoltaic (PV) system or a solar thermal technology is placed into operation, an eligible developer or financer of that solar project may claim a credit on its federal corporate income taxes for a certain percentage of the cost of the PV system during that applicable tax year. 26 U.S.C. § 48(a)(3)(A). The ITC's annual value is represented as a percentage of the given commercial project's qualifying investment costs. Solar ITCs help facilitate solar energy development by rewarding investment in solar equipment.

Over the years, Congress has continued to extend the 30% ITC. The ITC was set to step down to 10% on January 1, 2016; however, in December 2015 Congress extended the 30% solar ITC for an additional five years, through December 31, 2019, in its omnibus spending bill, the Consolidated Appropriations Act of 2016, Pub. L. No. 114-113, div. P, tit. III, § 303, 129 Stat. 2242 (2015). The ITC stepped down to 26% in 2020 and was scheduled to step down to 22% in 2021 and 10% in 2022.

As part of the federal government's recent year-end $2.3 billion spending and COVID-19 relief package, in the Consolidat-

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On January 15, 2016, Secretary Sally Jewell issued Secretarial Order No. 3338, which directed the Bureau of Land Management (BLM) to conduct a programmatic review of the federal coal management program under the National Environmental Policy Act. Secretary Jewell directed BLM to consider the climate change impacts of the coal program, whether the agency was receiving a fair return for the sale of federally owned coal, concerns about future market conditions for coal, and other issues. Secretary Jewell ordered a "pause" on issuing new federal coal leases for thermal coal until the programmatic review was complete. *See* Vol. XXXIV, No. 2 (2017) of this *Newsletter*.

Secretary Zinke revoked Secretary Jewell's order on March 29, 2017. *See* Secretarial Order No. 3348. The Zinke order underscored the federal coal management program's "critical importance to the economy of the United States" and directed BLM to "process coal lease applications and modifications expeditiously" in accordance with law. *Id.*

Secretary Haaland's April 2021 order revoked Secretary Zinke's March 2017 order but it is unclear whether the new order was intended to reinstate the original moratorium ordered by Secretary Jewell. Nonetheless, the Secretary has broad discretion to decline to issue new coal leases and the Biden administration's deemphasis on coal in favor of less carbon-intensive fuels and renewable energy makes it unlikely that Interior will authorize any significant new federal coal leases in the near term.

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- NEPA analysis for approvals "related to pending litigation, and/or in high priority or high conflict areas," including high priority sage-grouse habitat; wildlife migration corridors; lands with wilderness characteristics; lands with "special designations"; and where "there is consideration of a special management designation in a draft [resource management plan (RMP)] or RMP Amendment that has been issued";
- reinstatement of terminated oil and gas leases;
- extension of APDs;
- lease suspensions; and
- applications for royalty relief.

Although these actions require Assistant Secretary review, they do not require Assistant Secretary approval. This memorandum has no expiration date.

ONRR Delays Effective Date of Royalty Valuation Rule

By a notice issued on April 16, 2021, the Office of Natural Resources Revenue (ONRR) delayed the effective date of revisions to its federal oil and gas valuation and civil penalty rules until November 1, 2021. *See* 86 Fed. Reg. 20,032 (Apr. 16, 2021). ONRR initially published the revisions on January 15, 2021, 86 Fed. Reg. 4612, and they were scheduled to take effect on February 16, 2021. *See* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. Before then, ONRR delayed the effective date until April 16, 2021. *See* 86 Fed. Reg. 9286 (Feb. 12, 2021). ONRR explained that the delayed effective date will allow ONRR to consider "whether it will revise or withdraw some or all of that rule due to apparent defects in that rule." 86 Fed. Reg. at 20,032.

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Editors

Mining - Mark S. Squillace
University of Colorado

Oil and Gas - John S. Lowe
Southern Methodist University

Reporters

Federal – Mining
Kathleen C. Schroder
Davis Graham & Stubbs LLP

Federal – Oil & Gas
Wells Parker & Benjamin Machlis
Dorsey & Whitney LLP

Renewable Energy - Mark D. Detsky &
Gabriella Stockmayer
Dietze and Davis, P.C.

Congress/Federal Agencies
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Amy Mowry
Jost Energy Law, P.C.

Canada - Christopher G. Baldwin &
Christine Kowbel
Lawson Lundell LLP

Donald Greenfield &
Matthew Cunningham
Bennett Jones LLP

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BLM Adopts New Onshore Oil and Gas Leasing Procedures

On April 30, 2021, the Bureau of Land Management (BLM) released Instruction Memorandum No. 2021-027, "Oil and Gas Leasing—Land Use Planning and Lease Parcel Reviews." This IM replaces IM No. 2010-117, "Oil and Gas Leasing Reform—Land Use Planning and Lease Parcel Reviews" (May 17, 2010), and supersedes IM No. 2018-034, "Updating Oil and Gas Leasing Reform—Land Use Planning and Lease Parcel Reviews" (Jan. 31, 2018). IM 2010-117 was issued under Secretary Salazar and established a lease sale schedule that rotated among BLM field offices. IM 2018-034 was issued under Secretary Zinke and established a streamlined approach to leasing, which was subsequently enjoined in greater sage-grouse habitat.

IM 2021-027 establishes a leasing process that facially appears to straddle the approaches outlined in IM 2010-117 and IM 2018-034. It does not mandate a rotating lease schedule, as emphasized in IM 2010-117, but permits and encourages state offices to develop a rotating schedule. Unlike IM 2010-117, IM 2010-027 does not require site visits to potential lease parcels.

IM 2021-027 directs state offices to post notices of lease sales at least 45 days prior to a sale. It also provides for a 30-day protest period, beginning from the day the sale notice is posted. IM 2021-027 does not require that state offices resolve protests prior to a sale and, further, contemplates that protest resolution may take more than 60 days.

Notably, BLM explained it will not initiate any master leasing plans, which were a key component of IM 2010-117.

BLM offered no explanation as to how its adoption of new leasing procedures relates to the ongoing "pause" in oil and gas leasing and the U.S. Department of the Interior's review of the federal oil and gas leasing and permitting process. *See* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*.

IBLA Narrows Circumstances in Which Flaring Qualifies as an Emergency Under NTL-4A

In *Petro-Hunt, L.L.C.*, 197 IBLA 100, GFS(O&G) 2(2021), the Interior Board of Land Appeals (IBLA) outlined how the Bureau of Land Management (BLM) should apply Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases 4A (NTL-4A) when evaluating whether gas flared due to pipeline capacity or processing facility constraints was unavoidably lost and thus royalty free.

The decision addresses the interplay between different sections of NTL-4A. Section II of NTL-4A defines "unavoidably lost" and "avoidably lost" production based in part on an operator's efforts or failure to take reasonable measures to prevent or control the loss of gas. *Id.* at 102. Section III identifies circumstances in which operators may vent or flare on a short-term basis, including emergencies; section III authorizes royalty-free flaring for up to 24 hours per incident and 144 hours cumulatively for each calendar month due to emergencies. *Id.* Section IV allows a lessee to apply for royalty-free treatment of flared gas by providing "engineering, geologic, and economic data" to show that conservation of gas was not economically feasible. *Id.*

The appellant, Petro-Hunt, L.L.C (Petro-Hunt), sought review of six decisions of the BLM Montana-Dakotas State Director affirming 24 decisions of the BLM North Dakota Field Office granting in part and denying in part Petro-Hunt's requests for royalty-free flaring. *Id.* at 100. Petro-Hunt had flared the gas because the gas purchaser "was not able to accept" the gas due to "force majeure events, maintenance, and/or capacity issues in the third-party gas gathering and processing system." *Id.* at 106.

The field office had determined that the flaring was due to emergency circumstances under section III of NTL-4A and granted the requests for royalty-free flaring for 24 hours per incident and 144 hours for each calendar month. Beyond these thresholds, the field office found the flaring was royalty-bearing. *Id.* at 104–05. The State Director upheld the field office's decisions. *Id.* at 107–09.

On appeal before the IBLA, Petro-Hunt argued that BLM erred by applying the emergency provision in section III of NTL-4A and that BLM should have instead applied section II to evaluate whether Petro-Hunt took reasonable measures to control the loss of gas. *Id.* at 110.

The IBLA first addressed Petro-Hunt's argument that its flaring did not qualify for emergency treatment under section III. *Id.* Petro-Hunt maintained that flaring was not short-term, temporary, or abnormal, but rather that chronic infrastructure limitations in the Williston Basin resulted in "systemic gas gathering, compression, and processing constraints" requiring flaring. *Id.* Citing BLM's own recognition that "chronic and recurring rather than sudden and unforeseen" circumstances caused the need to flare gas, the IBLA held that BLM lacked a rational basis for treating the flared gas as unavoidably lost under the emergency provision of section III. *Id.* at 111.

Next, the IBLA reviewed BLM's determination that gas was not unavoidably lost under section II. *Id.* The IBLA found that section IV defines the information needed to demonstrate that flared gas was unavoidably lost under section II. *Id.* at 112. Petro-Hunt, however, admitted on appeal that the information it provided to BLM did not meet the requirements of section IV. *Id.* Consequently, the IBLA agreed with BLM that Petro-Hunt provided inadequate information to support its position that gas was unavoidably lost under section II. *Id.* at 113.

Because the Montana State Director's decision incorrectly applied section III to treat some flaring as royalty-free, the IBLA remanded the State Director's decision to BLM to determine "whether to deny Petro-Hunt's requests on account of Petro-Hunt's failure to support those requests with adequate information and analysis." *Id.* at 115.

This decision is significant both because of the IBLA's narrow interpretation of the emergency provision in section III of NTL-4A and because the IBLA had not previously addressed the relationship between sections II and VI of NTL-4A.

IBLA Upholds BLM's Rejection of Offers to Lease Oil and Gas

In *Tempest Exploration Co.*, 196 IBLA 386, GFS(O&G) 1(2021), the Interior Board of Land Appeals (IBLA) upheld a Bureau of Land Management (BLM) Utah State Office decision denying Terry Tempest Williams and Brooke S. Williams d/b/a Tempest Exploration Co., LLC's (collectively, Tempest) non-competitive offer to purchase oil and gas leases.

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.

Tempest had submitted noncompetitive lease offers under the Mineral Leasing Act (MLA) for two parcels in Utah. *Id.* at 387. Subsequently, Tempest publicly stated its intention to "keep whatever oil and gas lies beneath these lands in the ground . . . until science finds a way to use those fossil fuels in sustainable, nonpolluting ways." *Id.* at 388. BLM ultimately rejected Tempest's lease offers after concluding that Tempest's public statements conflicted with the "diligent development requirement" in the MLA and federal oil and gas leases. *Id.* at 390. Tempest appealed, arguing BLM erred by treating Tempest differently from other bidders and by defining "reasonable diligence" too narrowly. *Id.* at 391.

Tempest first claimed it was treated differently from other similarly situated parties. *Id.* at 392. Tempest compared its situation to BLM's treatment of (1) Victoria Ramos, a woman whose lease bid was accepted, even though her original intention was "to keep the oil and gas on her lease in the ground"; and (2) other oil and gas operators who defer development until economic conditions favor it. *Id.* at 394–95. The IBLA disagreed and found significant differences between Tempest and the two examples, because Victoria Ramos eventually showed interest in development and the operators that delayed drilling still intended to develop the leased resources. *Id.* at 395–97.

Tempest also disputed BLM's application of the "reasonable diligence" standard in the MLA. The MLA requires lessees to exercise "reasonable diligence, skill, and care in the operation of [leased] property." *Id.* at 398 (quoting 30 U.S.C. § 187). The IBLA interprets this standard as the "prudent operator" rule—"[w]hatever, in the circumstances, would be reasonably expected of operators of ordinary prudence." *Id.* (alteration in original) (quoting *CSX Oil & Gas Corp.*, 104 IBLA 188, 196, GFS(O&G) 87(1988)). Further, the IBLA has found that a prudent operator in an oil and gas lease would have a reasonable expectation of a financial gain. *Id.* at 399.

Here, Tempest argued the "reasonable diligence" standard should be "evaluated contextually" and BLM needs to analyze each lessee's "chosen economic calculus" when determining diligence. *Id.* at 398, 400. Tempest asserted its decision to forgo development "given the social cost of carbon" was diligent according to Tempest's "chosen economic calculus." *Id.* However, the IBLA held that the "reasonable diligence" standard is not a subjective measure and "a party 'cannot justify its act or omission on personal grounds or by reference to its peculiar circumstances.'" *Id.* at 400 (quoting 5 Patrick H. Martin & Bruce M. Kramer, *Williams & Myers, Oil and Gas Law* § 806 (2013)). Moreover, the IBLA reasoned that BLM cannot create or modify existing laws, nor can it ignore the MLA regulations, as Tempest argued it should do. *Id.* at 402–03.

Overall, Tempest's arguments failed to persuade the IBLA that BLM erred in its denial of Tempest's noncompetitive lease offers. *Id.* at 403. The IBLA affirmed BLM's decision but modified the decision "to the extent it was based on the conclusion that Tempest had committed not to develop its leases under any circumstances, rather than a determination that Tempest's stated preconditions to development did not comport with the applicable legal standard for the obligation of 'reasonable diligence.'" *Id.* at 403–04.

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ed Appropriations Act of 2021, Pub. L. No. 116-260, 134 Stat. 1182 (2020), Congress once again extended the commercial solar ITC. The final division of the Act, titled the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (Taxpayer Act), Pub. L. No. 116-260, div. EE, 134 Stat. 1182, addresses renewable energy provisions, including the extension of the solar ITC. *Id.* § 132 (Extension and Phaseout of Energy Credit). The Taxpayer Act extended the ITC for not only commercial projects, including industrial and utility-scale level projects, but also residential solar projects. Under the Taxpayer Act, commercial solar projects that commence construction in either 2021 or 2022 (no later than December 31, 2022) will be eligible for the 26% ITC before it falls to 22% beginning in 2023. In 2024, the ITC will be further reduced to 10%. The most recent extension of the ITC is significant, as ITCs continue to remain a critical cost driver of commercial solar projects in the renewable energy space.

The Taxpayer Act similarly extended the federal production tax credit (PTC), which is a corporate tax credit for wind energy development and other eligible renewable sources. The PTC was otherwise set to expire at the end of 2020.

The PTC incentivizes wind turbine projects and other eligible renewable sources by providing a per-kilowatt-hour credit for electricity generated. Pursuant to section 45 of the Internal Revenue Code, a qualified wind energy developer may claim a PTC for each kilowatt hour of electricity that is sold during the decade subsequent to the wind project's in-service date. 26 U.S.C. § 45.

Congress first enacted the PTC in 1992, a little over a decade prior to the solar ITC's passage, and it has been extended over a dozen times. *See* Energy Policy Act of 1992, Pub L. No. 102-486, 106 Stat. 2776. For wind facilities that commenced construction in 2019, a developer qualified for 40% of the full credit amount. In 2020, instead of stepping down like the solar ITC in that year, wind projects were able to claim a PTC of 60% of the full credit amount.

With the Taxpayer Act's extension of the 2020 PTC, all wind energy systems beginning construction in 2020 through the end of 2021 are eligible for a PTC at 60% of the full credit amount of 2.5 per kilowatt hour. *See* Credit for Renewable Elec. Prod., Refined Coal Prod., & Indian Coal Prod., & Publication of Inflation Adjustment Factors & Reference Prices for Calendar Year 2021, I.R.S. Notice 2021-32, 2021-21 I.R.B. 1159.

Order No. 872 Implementing PURPA

The Public Utility Regulatory Policies Act (PURPA), Pub. L. No. 95-617, 92 Stat. 3117, was passed in 1978 in an effort to decrease the country's dependence on conventional fossil fuel sources such as oil and natural gas, encourage energy diversity, and introduce competition into the electric market. To that end, PURPA, and its implementing regulations, generally require traditional, regulated utilities to purchase power from qualifying cogeneration projects and qualifying small power production facilities ("Qualifying Facilities" or "QF") at the utilities' "avoided costs." 16 U.S.C. § 824a-3(a); 18 C.F.R. § 292.304(a)(2). "Avoided costs" is defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6).

On September 19, 2019, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking seeking to modify key aspects of the regulations implementing PURPA. *See* Qualifying Facility Rates and Requirements Implementation Issues Under PURPA, 168 FERC ¶ 61,184 (2019). FERC cited three changes since the passage of PURPA that prompted the rulemaking: (1) the United States has seen an increase in the supply of natural gas due to technological advances; (2) there has been a growth of alternative energy sources, particularly with respect to renewables, which have become cost competitive and provide a significant share of the electricity generated in the United States; and (3) the introduction of QFs as competitors to traditional utilities has led to the significant development of larger independent power production facilities. *See* 85 Fed. Reg. 54,638, 54,647–48 (Sept. 2, 2020) (to be codified at 18 C.F.R. pts. 292, 375). According to FERC, the changes to PURPA's implementing regulations were intended to continue to encourage the development of QFs while better aligning PURPA's regulations with the changes in the modern energy landscape.

On July 16, 2020, FERC issued its final rulemaking in Order No. 872. *See* 172 FERC ¶ 61,041 (July 16, 2020). FERC affirmed Order No. 872 on November 19, 2020, *see* 173 FERC ¶ 61,158 (Nov. 19, 2020), and the rule took effect on December 31, 2020. Although it has been in place for several months now, the implications of Order No. 872 for the renewable energy sector cannot be understated, and thus a summary of the Order's key changes to PURPA are appropriate for this first Renewable Energy section of this *Newsletter*.

Changes to Rates

Under the prior regulations, a QF had two options for how to sell its power to a traditional electric utility: (1) a QF could sell as much of its energy as it chose, when such energy became available, at the rate calculated at the time of delivery; or (2) the QF could sell its energy pursuant to a contract (known as a legally enforceable obligation or "LEO") over a specified term, at either the purchasing utility's avoided cost calculated at the time of delivery, or the utility's avoided cost calculated at the time the LEO was incurred. 18 C.F.R. § 292.304(d)(1)–(2). However, FERC determined that long-term fixed price contracts sometimes exceeded the utilities' actual avoided costs at the time of delivery. 85 Fed. Reg. at 54,643.

Although the new rule maintains fixed avoided cost rates for QF capacity contracts, states now have the flexibility to require variable *energy* rates for QF sales. That is, state regulatory authorities can now require that energy rates (but not capacity rates) in QF power sale contracts vary based on the utilities' as-available avoided costs at the time of energy delivery, rather than being fixed for the term of the contract. 18 C.F.R. § 292.304(d)(2). States are not required to adopt variable energy contracts permitted by Order No. 872, but if they choose to do so, QFs no longer have the ability to elect to have fixed energy rates. 85 Fed. Reg. at 54,648. According to FERC, this change gives states the flexibility "to ensure that the avoided cost rate will be closer to the actual rate the purchasing electric utility and its customers would have paid if the purchasing electric utility had generated this electric energy itself or purchased such electric energy from another source." *Id.* at 54,645.

Order No. 872 also established a rebuttable presumption that the locational marginal price (LMP) established in the Western Energy Imbalance Market and the organized electric markets defined in 18 C.F.R. § 292.309(e), (f), or (g)—i.e., Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO-NE), and New York Independent System Operator, Inc. (NYISO); Electric Reliability Council of Texas (ERCOT); and California Independent System Operator and Southwest Power Pool, Inc., respectively—represent the as-available avoided energy cost of electric utilities located in these markets. *Id.* § 292.304(b)(6), (e)(1); 85 Fed. Reg. at 54,663. In areas outside of these RTO/ISO markets, FERC also established a rebuttal presumption that prices established using liquid market hubs or, in the absence of such hubs, based on formulas from natural gas prices indices and proxy heat rate appropriately establish the as-available energy avoided cost rate. 18 C.F.R. § 292.304(b)(7), (e)(1). An aggrieved QF may challenge a state's decision to set avoided costs in these ways, in proper relevant state commission proceedings, in a judicial review action under PURPA § 210(g), or filing an enforcement petition with FERC, and later against the state in federal district court if FERC declines under PURPA § 210(h)(2)(B).

In addition, Order No. 872 gives state commissions the authority to set energy and capacity rates in a competitive solicitation process conducted pursuant to transparent and nondiscriminatory procedures, consistent with the principles articulated in *Allegheny Energy Supply Co.*, 108 FERC ¶ 61,082, at P 18 (2004) (establishing four guidelines for competitive solicitations: (1) transparency, (2) clearly defined products, (3) standardized evaluations, and (4) oversight). 18 C.F.R. § 292.304 (b)(8), (e)(1). Such a competitive solicitation must be conducted in a process that includes, but is not limited to, the following factors:

> (A) The solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards;
>
> (B) Solicitations are open to all sources, to satisfy that [purchasing] electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;
>
> (C) Solicitations are conducted at regular intervals;
>
> (D) Solicitations are subject to oversight by an independent administrator; and
>
> (E) Solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report.

Id. § 292.304(b)(8)(i). Solicitations that do not comport with these standards are presumptively in violation of PURPA's implementing regulations.

Modification to FERC's "One-Mile Rule"

Under PURPA, to qualify as a QF, a renewable energy facility cannot have a power production capacity, together with any other facilities located at the same site, that is greater than 80 megawatts. 16 U.S.C. § 796(17)(A). In 1980, FERC established the one-mile rule, which determined that facilities that are owned by the same or affiliated entities and use the same energy resource should be deemed to be at the same site for QF purposes if they are located within one mile of the facility for which QF status is sought. *See* 45 Fed. Reg. 17,959 (Mar. 20, 1980) (codified as amended at 18 C.F.R. § 292.204(a)(2)(i)). During the rulemaking, several parties argued that QF developers of small power production facilities were evading FERC's one-mile rule, and circumventing PURPA, by siting their facilities that used the same energy resource just over one mile apart to qualify as separate facilities for QF purposes. *See* 85 Fed. Reg. at 54,696.

Order No. 872 amended the one-mile rule such that if a small power production facility seeking QF status is located one mile or less from an affiliated power producer using the same energy source, an irrebuttable presumption will be established that it is at the same site for purposes of the 80 MW cap. Likewise, if two power production facilities are located more than 10 miles apart, there is an irrebuttable presumption that they are at separate sites. However, for a small power production facility seeking QF status that is located more than one mile but less than 10 miles from an affiliated facility using the same power source, FERC's new rule creates a rebuttable presumption that they constitute separate sites. 18 C.F.R. § 292.204(a)(2).

Restrictions on a Utility's Obligation to Purchase

In 2005, PURPA was amended to relieve utilities of their obligation to purchase energy from a QF if the QF had nondiscriminatory access to the market. *See* 16 U.S.C. § 824a-3(m). In a subsequent rulemaking, FERC established a rebuttable presumption that a QF with a net power production capacity below 20 MW would not have access to competitive markets because of its small size. *See* 18 C.F.R. § 292.309(d)(1) (2007). Order No. 872 reduced this threshold, finding that "small power production facilities with a net power production capacity at or below 5 MW will be presumed *not* to have nondiscriminatory access to markets, and, conversely, small power production facilities with a net power production capacity over 5 MW will be presumed to have nondiscriminatory access to markets." 85 Fed. Reg. at 54,715; *see also* 18 C.F.R. § 292.309(d)(2). FERC amended this rule in part because it determined QFs have better access to today's energy markets and are better able to compete with other energy producers than they were when PURPA was first enacted.

Challenges to QF Status

Prior to Order No. 872, a party wishing to challenge a QF's certification would have to file a petition for declaratory order and pay a substantial filing fee. FERC's new rules create a new procedural mechanism whereby interested parties may now file a protest in QF certification proceedings before FERC within the time limits imposed by the rule. 18 C.F.R. § 292.207(c).

Legally Enforceable Obligation

Under PURPA, after a QF is certified, the mandatory purchase obligation is created when the QF enters into a legally enforceable obligation (LEO) with a utility. Order No. 872 places additional restrictions on when PURPA's must-purchase obligation is triggered. It adds the additional requirement that QFs demonstrate that a proposed project is commercially viable and has a financial commitment, pursuant to objective state-determined criteria, in order for the QF to be eligible for a LEO. 18 C.F.R. § 292.304(d)(2). According to FERC, this new requirement will ensure that no electric utility's obligation to purchase is triggered for QF projects that are not sufficiently advanced in their development, such that it would be unreasonable for a utility to include it in its resource planning. 85 Fed. Reg. at 54,721.

CONGRESS / FEDERAL AGENCIES – GENERAL

John H. Bernetich & Dale Ratliff
– Reporters –

Biden Administration Proposes to Reinstate the Migratory Bird Treaty Act Prohibition on Incidental Take

On May 7, 2021, the U.S. Fish and Wildlife Service (FWS) issued a proposed rule that would revoke a final rule issued in the waning days of the Trump administration that limited the scope of the Migratory Bird Treaty Act's (MBTA) criminal penalties. *See* 86 Fed. Reg. 24,573 (proposed May 7, 2021). The prior rule, issued in January 2021, narrowed the scope of the MBTA's criminal penalties to only intentional take (and not incidental take) of migratory birds. *See* 86 Fed. Reg. 1134, 1137 (Jan. 7, 2021) (codified at 50 C.F.R. § 10.14); *see also* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. If finalized, the effect of the May 7 proposed rule would be a return to implementing the MBTA to prohibit intentional *and* incidental take, with emphasis on enforcement discretion. Comments on the proposed rule are due by June 7, 2021.

In the most recent edition of this *Newsletter*, we summarized the January 7, 2021, final rule, which clarified that the MBTA's prohibition on "take" of migratory birds applies only to actions "directed at" migratory birds and their nests and eggs, and does not prohibit the incidental or unintentional "take" of birds. 86 Fed. Reg. at 1137. Under the January 2021 rule and the Solicitor of the Interior's legal opinion that accompanied the rule, the MBTA's take prohibition applies only "to affirmative actions that have as their purpose the taking or killing of migratory birds." Solicitor's Opinion M-37050 (Dec. 22, 2017) (M-37050).

After the new administration took office, FWS announced that the effective date of the January 2021 final rule would be delayed until March 8, 2021. *See* 86 Fed. Reg. 8715 (Feb. 9, 2021). Then, on March 8, 2021, the Solicitor withdrew M-37050, which served as the legal basis for the January 2021 rule limiting the scope of the MBTA's penalties. *See* Solicitor's Opinion M-37065 (Mar. 8, 2021). In the memorandum revoking M-37050, the Solicitor cited a federal district court decision vacating M-37050 as contrary to the unambiguous language of the MBTA. *See Nat. Res. Def. Council, Inc. v. U.S. Dep't of the Interior*, 478 F. Supp. 3d 469 (S.D.N.Y. 2020).

FWS's May 7, 2021, proposed rule would revoke the January 2021 rule issued by the Trump administration limiting the MBTA's scope to only intentional take. FWS concluded that "the interpretation of the MBTA set forth in the January 7 rule and Solicitor's Opinion M-37050, which provided the basis for that interpretation, is not the construction that best accords with the text, purposes, and history of the MBTA." 86 Fed. Reg. at 24,575. FWS determined that implementing the statute to prohibit incidental take reflects Congress's intent in enacting the MBTA and "the conservation purposes of the statute" and its underlying international treaties. *Id.*

FWS did not further postpone the effective date of the January 2021 rule prohibiting only intentional take. As a result, the January 2021 rule went into effect on March 8, 2021, and will remain in effect until FWS issues a final rule revoking it. 86 Fed. Reg. at 24,573.

Senate Votes to Repeal Trump Administration NSPS OOOOa "Policy Rule"

On April 28, 2021, the Senate voted 52-42 to adopt Senate Joint Resolution 14. The joint resolution provided for congressional disapproval under the Congressional Review Act (CRA), 5 U.S.C. §§ 801–808, of the U.S. Environmental Protection Agency's (EPA) September 14, 2020, amendments to New Source Performance Standard (NSPS) OOOOa. *See* 85 Fed. Reg. 57,018 (Sept. 14, 2020) (amending 40 C.F.R. pt. 60). The 2020 amendments to NSPS OOOOa, known generally as the NSPS OOOOa "Policy Rule," effectuated two major changes to the rules: (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.

NSPS OOOOa was the second NSPS rule directed at the oil and natural gas production sector. EPA published the initial NSPS OOOO in 2012. *See* 77 Fed. Reg. 49,490 (Aug. 16, 2012). NSPS OOOO enacted first-of-their-kind control requirements for numerous upstream oil and natural gas emission sources, including drilling operations for natural gas wells, storage vessels, and pneumatic controllers. NSPS OOOO exclusively regulated volatile organic compounds (VOCs) from these sources. The Obama EPA published NSPS OOOOa in 2016. *See* 81 Fed. Reg. 35,824 (June 3, 2016). NSPS OOOOa expanded the requirements under NSPS OOOO by (1) adding methane as a regulated pollutant in addition to VOCs, (2) adding the storage and transmission sector to the purview of the rules, and (3) promulgating leak detection and repair (LDAR) requirements. The 2020 Policy Rule published under the Trump administration removed methane as a regulated pollutant and removed the transmission and storage segment from the rule.

Reverting back to the 2016 NSPS OOOOa restores the transmission and storage sectors to the rule, resulting in continued emission reductions from those sectors. The removal of methane, on the other hand, as applied to upstream production sources, will not result in actual emission reductions under NSPS OOOOa. EPA acknowledged in the final 2016 NSPS OOOOa that the methane reductions achieved by the rule were simply a co-benefit from application of the VOC standards. 81 Fed. Reg. at 35,827. Because the Policy Rule did not change any of the substantive requirements that apply to oil and natural gas upstream and midstream sources, such as those for storage vessels, LDAR, pneumatic controllers, and compressors, the methane reductions achieved would have remained the same under the Policy Rule as they will under the 2016 rule. 85 Fed. Reg. at 57,019.

An important consequence of the CRA rescission of the Policy Rule, and reinstatement of the 2016 NSPS OOOOa, is its impact on EPA's authority to regulate existing sources under section 111(d) of the Clean Air Act, 42 U.S.C. § 7411(d). Section 111(d) requires EPA to regulate existing sources based on the NSPS for a source category. But section 111(d) does not apply to criteria pollutants. Because VOCs are a precursor to ozone, they are considered a criteria pollutant for purposes of section 111(d), and thus EPA acknowledged in the final Policy Rule that "methane NSPS, but not VOC NSPS, would trigger the CAA section 111(d) requirements for existing sources." 85 Fed. Reg. at 57,033.

ENVIRONMENTAL ISSUES

Randy Dann, Kate Sanford & Michael Golz
– Reporters –

Federal Courts Take Up Federal Removal and Preemption Issues in Climate Change Cases

U.S. Supreme Court Takes Up Federal Removal Issues

Over the past year, an increasing number of municipalities, counties, and states have filed climate change related lawsuits in state court, asserting claims against fossil fuel companies under common law causes of action, such as public and private nuisance. Generally, the plaintiffs claim that the companies' contribution to global warming has caused them to suffer various climate change related injuries. Their claims are more likely to succeed in state court rather than federal court because federal common law claims are preempted by the Clean Air Act (CAA) and other federal doctrines. *See Am. Elec. Power Co. v. Connecticut* (*AEP*), 564 U.S. 410, 424 (2011); *Native Vill. of Kivalina v. ExxonMobil Corp.*, 696 F.3d 849, 857–58 (9th Cir. 2012).

As such, defendants have sought to remove the cases to federal court and have relied on a plethora of removal statutes as the bases for doing so. One of those bases—which has taken center stage in recent litigation—is the federal officer removal statute. The statute allows defendants sued in state court for acts taken under the direction of a federal officer and under color of federal office to remove a case to federal court. Defendants have argued that their contracts with the federal government required them to take some of the actions for which they were being sued or that their "conduct on federal land and at the direction of federal officers is sufficient to support federal jurisdiction." Appellants' Opening Brief at 3, *Rhode Island v. Shell Oil Prods. Co.*, 979 F.3d 50 (1st Cir. 2020), 2019 WL 6463536; *see also, e.g.*, *Mayor & City Council of Balt. v. BP P.L.C.*, 952 F.3d 452, 462 (4th Cir. 2020), *cert. granted*, 141 S. Ct. 222 (2020).

Removing these cases from state courts to federal district courts is the first move in the procedural game of ping pong between state and federal court. Once the cases are removed to federal district court, judges across the country have uniformly remanded the cases back to state court. Under federal law, most orders remanding a case to state court cannot be appealed. 28 U.S.C. § 1447(d). However, the federal officer removal statute, *id.* § 1442, and the civil rights removal statute, *id.* § 1443, provide two narrow exceptions to this rule. Thus, when defendants appeal the cases to federal circuit courts, their arguments are limited to these statutes.

To date, the First, Fourth, Ninth, and Tenth Circuits have held that removal under the federal officer removal statute was not proper and have rejected the companies' arguments that they could review the district court orders remanding the cases back to state court. *See Rhode Island v. Shell Oil Prods. Co.*, 979 F.3d 50, 59–60 (1st Cir. 2020), *petition for cert. docketed*, No. 20-900 (Jan. 5, 2021); *Mayor & City Council of Balt.*, 952 F.3d at 456; *Cty. of San Mateo v. Chevron Corp.*, 960 F.3d 586, 600–03 (9th Cir. 2020), *petition for cert. docketed*, No. 20-884 (Jan. 4, 2021); *Bd. of Cty. Comm'rs of Boulder Cty. v. Suncor Energy (U.S.A.) Inc.*, 965 F.3d 792, 821–27 (10th Cir. 2020), *petition for cert. docketed*, No. 20-783 (Dec. 8, 2020). The defendants have responded by filing petitions for certiorari seeking review by the U.S. Supreme Court. In October 2020, the U.S. Supreme Court granted a petition for certiorari in one of those cases—the Fourth Circuit's *Mayor & City Council of Baltimore*—and agreed to review whether appellate review of remand orders "permits a court of appeals to review any issue encompassed in a district court's order remanding a removed case to state court where the removing defendant premised removal in part on the federal-officer removal statute or the civil-rights removal statute." Petition for a Writ of Certiorari at I, *BP P.L.C. v. Mayor & City Council of Balt.*, No. 19-1189 (U.S. Mar. 31, 2020), 2020 WL 1557798 (citations omitted). On January 19, 2021, the U.S. Supreme Court heard oral argument, and the justices appeared to be divided on the issue. Justice Samuel Alito is recused from the case, making it somewhat likely that there will be a 4-4 split among the justices. If this happens, the decision from the Fourth Circuit will stand. This ruling will impact 19 other similar climate change cases around the country and will likely decide whether climate change lawsuits are decided on the merits in state or federal court.

Federal Courts Wrestle with Preemption Issues

In addition to the federal officer removal statute, fossil fuel companies have consistently raised preemption as a basis for federal removal jurisdiction in state law nuisance claims against them. While it is well established that federal common law claims are preempted by the CAA and other federal doctrines, courts are just beginning to thoroughly address whether state law claims are also preempted. Because 28 U.S.C. § 1447 limits the scope of appellate review of orders remanding removed cases, recent decisions by the First, Fourth, and Tenth Circuits did not address preemption. However, the issue was discussed extensively at the district court level.

For example, in *Mayor & City Council of Baltimore v. BP P.L.C.*, 388 F. Supp. 3d 538 (D. Md. 2019), the City of Baltimore sued 26 oil and gas companies in state court. The City sought monetary damages and equitable relief, alleging that the companies' production, distribution, and promotion of fossil fuels caused climate-related injuries, including rising sea levels along Maryland's coast. *Id.* at 548. Two of the defendants timely removed the lawsuit to the U.S. District Court for the District of Maryland. *Id.* at 548–49. The City then filed a motion to remand to state court. *Id.* at 549. In response, the defendants asserted eight grounds for removal, including that (1) the CAA and foreign affairs doctrine completely preempted the City's claims, and (2) federal common law governed the City's public nuisance claim. *Id.*

The court granted the motion to remand. In addressing the defendants' arguments, the court observed that some cases may be removed to federal court under the doctrine of complete preemption, a "corollary of the well-pleaded complaint rule." *Id.* at 553 (quoting *Metro. Life Ins. Co. v. Taylor*, 481 U.S. 58, 63 (1987)). "Complete preemption is a jurisdictional doctrine that 'converts an ordinary state common-law complaint into one stating a federal claim for purposes of the well-pleaded complaint rule.'" *Id.* (quoting *Caterpillar Inc. v. Williams*, 482 U.S. 386, 393 (1987)). However, to remove a case on this basis, "a defendant must show that Congress intended for federal law to provide the 'exclusive cause of action' for the claim asserted." *Id.* (quoting *Beneficial Nat'l Bank v. Anderson*, 539 U.S. 1, 9 (2003)). Complete preemption is not to be confused with express, field, or conflict preemption. These forms of "ordinary" preemption serve only as defenses and consequently do not satisfy the well-pleaded complaint rule. *Id.* at 554.

The court took each of the defendants' preemption arguments in turn. First, as to the defendants' argument regarding the foreign affairs doctrine—the judicially crafted doctrine that "[t]he federal government has the exclusive authority to act on matters of foreign policy," *id.* at 561—the court reasoned that the doctrine could not evince congressional intent to provide an "exclusive cause of action" because it was created by judges. *Id.* at 562. Second, the court emphasized that the CAA contains a savings clause, 42 U.S.C. § 7604(e), that specifically preserves state common law actions—and thus does not provide a substitute, exclusive cause of action. 388 F. Supp. 3d at 562–63. Finally, as to the federal common law argument, the court remarked that any potential federal common law nuisance claim would likely be displaced by the CAA, which itself does not provide the exclusive cause of action. *Id.* at 557 (citing *AEP*, 564 U.S. at 424; *Kivalina*, 696 F.3d at 857–58). This conclusion dovetails with the court's ruling that judicially crafted doctrines, such as the foreign affairs doctrine, cannot show congressional intent.

District courts across the country seem to agree with the District of Maryland's reasoning. Rulings in Rhode Island and Colorado—appealed and reviewed on different bases—substantially track the reasoning of *Baltimore*. *See Bd. of Cty. Comm'rs of Boulder Cty. v. Suncor Energy (U.S.A.) Inc.*, 405 F. Supp. 3d 947, 969–74 (D. Colo. 2019); *Rhode Island v. Chevron Corp.*, 393 F. Supp. 3d 142, 148–50 (D.R.I. 2019); *see also Cty. of San Mateo v. Chevron Corp.*, 294 F. Supp. 3d 934, 937–38 (N.D. Cal. 2018). And a more recent ruling in the U.S. District Court for the District of Minnesota came to the same conclusion regarding the argument that federal common law displaces state law nuisance claims. *See Minnesota v. Am. Petroleum Inst.*, No. 0:20-cv-01636, 2021 WL 1215656 (D. Minn. Mar. 31, 2021), *appeal docketed*, No. 21-1752 (8th Cir. Apr. 5, 2021).

As mentioned, 28 U.S.C. § 1447 prevents appellate courts from reviewing most bases for opposing remand orders, including preemption. Recently, however, unique procedural postures allowed for appellate courts in the Ninth and Second Circuits to weigh in. The circuits appear to disagree about the preemptive scope of the CAA, though the Second Circuit ascribed this disagreement to differing standards for complete and ordinary preemption.

In *City of Oakland v. BP PLC*, the U.S. District Court for the Northern District of California permitted removal of Oakland and San Francisco's state public nuisance claims against several fossil fuel companies. *See* 969 F.3d 895, 902 (9th Cir. 2020), *petition for cert. docketed*, No. 20-1089 (Feb. 9, 2021). The court reasoned that the claims implicated "interstate and international disputes implicating the conflicting rights of States or . . . relations with foreign nations." *Id.* The court later dismissed the complaint for failure to state a claim, prompting an appeal to the Ninth Circuit.

The Ninth Circuit reversed, holding, among other things, that the cities failed to satisfy complete preemption, which the court referred to as the artful pleading doctrine. The court's opinion comports with the district court rulings cited above. The CAA contains a savings clause that preserves state common law claims. *Id.* at 907–08. Moreover, the CAA relies on cooperation between state and federal authorities, delegating regulatory authority to the states; displacement of state law claims would contradict the spirit of federalism evinced by the Act. *Id.* The court also reasoned that the CAA does not provide a substitute cause of action that would allow plaintiffs to seek compensatory damages for climate impacts. *Id.* at 908. Consequently, the CAA does not completely preempt state law nuisance claims. *Id.*

In April 2021, the Second Circuit provided conflicting insight into preemption of state law claims. In *City of N.Y. v. Chevron Corp.*, 993 F.3d 81 (2d Cir. 2021), unlike other recent climate change cases, the plaintiffs filed suit directly in federal court. Thus, the Second Circuit could review questions of ordinary preemption, rather than analyzing the well-pleaded complaint rule.

The Second Circuit held that the CAA ordinarily preempts state law claims. First, the court concluded that federal common law would displace state nuisance law claims. *Id.* at 91–92. Disputes involving interstate air pollution implicate two federal interests that are incompatible with application of state tort law: "(i) the 'overriding . . . need for a uniform rule of decision' on matters influencing national energy and environmental policy, and (ii) 'basic interests of federalism.'" *Id.* (quoting *Illinois v. City of Milwaukee*, 406 U.S. 91, 105 n.6 (1972)). Second, the CAA in turn displaces federal common law. *Id.* at 95. The court reasoned that successful state law claims for damages would effectively regulate greenhouse gas emissions. Such regulation is impermissible because "Congress has already 'spoken directly to th[at] issue' by 'empower[ing] the EPA to regulate [those very] emissions.'" *Id.* at 96 (alterations in original) (quoting *Kivalina*, 696 F.3d at 857–58). Recognizing that New York's lawsuit could also regulate foreign production of fossil fuels, the court noted that the CAA would not displace federal common law claims based on foreign emissions. *Id.* at 101. However, the court advised federal judges to avoid entertaining such claims, which might complicate foreign policy and step on the toes of the political branches. *Id.* at 102.

In reaching a different conclusion from the Ninth Circuit regarding the CAA's preemption of state law claims, the Second Circuit leaned on the differing standards applied in each case. *Id.* at 93–94. The standard for complete preemption is undoubtedly stricter than for ordinary preemption; however, the Second Circuit's reasoning diverged from the Ninth Circuit in a dramatic fashion. Unlike the Second Circuit, the Ninth Circuit was unwilling to recognize a federal common law of nuisance for air pollution, leaving it an open question. *City of Oakland*, 969 F.3d at 906. In contrast, the Second Circuit relied on displacement of state law claims by federal common law to ultimately determine that the CAA would govern these types of disputes.

Additionally, the Ninth Circuit appeared to construe the CAA's savings clause more broadly. *Id.* at 907–08. The Second Circuit took a limited view, suggesting that the clause only preserves state lawsuits against a pollution source in the source's state. *City of N.Y.*, 993 F.3d at 100. Thus, the CAA preempted suits like the City of New York's, which would impose New York nuisance law standards on emissions from sources across the country—and the globe. *Id.* This potential disagreement between two prominent circuits about the scope of preemption is likely to rear its head in the future.

ARKANSAS – OIL & GAS

Thomas A. Daily
– Reporter –

2021 Arkansas General Assembly Enacts Two New Laws of Interest to the Mineral Bar

The recently concluded 2021 Arkansas legislative session resulted in two new laws of interest to the mineral bar.

Act No. 275, the Oil and Gas Lien Owners' Act of 2021, Ark. Code Ann. §§ 15-72-1101 to -1112 (effective 91 days after adjournment), established a lien in favor of "interest owners" (persons entitled to proceeds of oil and gas sales) in severed minerals and proceeds thereof, with priority dating from the moment of severance, to secure payment of such proceeds. The Act is substantially identical to Oklahoma's Oil and Gas Owners' Lien Act of 2010, Okla. Stat. tit. 52, §§ 549.1–.12, which was designed to give interest owners priority against other creditors of a marketer in the event of the marketer's bankruptcy.

Act No. 668 amended existing law with regard to the methodology for determining the assessed value of oil wells for purposes of ad valorem taxation. *See* Ark. Code Ann. § 26-26-1110 (amendments effective 91 days after adjournment). Valuation of oil in place must now be based upon the previous year's production. The Act also provides for taxation of oil well production equipment as real property. It provides that such production shall be assessed at a value of one dollar per foot, measured from the bottom of its casing to the sales valve at the tank battery.

Federal Court of Appeals Affirms District Court's Summary Judgment Dismissing Plaintiff's Claim of Conversion Through Illegal Commingling of Gas Within Wellbore

J.B. Turner sued XTO Energy Inc. (XTO) contending that it had secretly commingled gas from a formation in which he owned a working interest with gas from a shallower formation where his interest was non-consent. In *Turner v. XTO Energy Inc.*, No. 2:18-cv-02171, 2019 WL 3577676 (W.D. Ark. Aug. 6, 2019), the U.S. District Court for the Western District of Arkansas entered summary judgment dismissing Turner's complaint as barred by limitations. *See* Vol. XXXVI, No. 4 (2019) of this *Newsletter*.

That decision has now been affirmed by the U.S. Court of Appeals for the Eighth Circuit. *See Turner v. XTO Energy Inc.*, 989 F.3d 625 (8th Cir. 2021). Turner had appealed the district court's conclusions that his case was barred by limitations and its implicit holding that, regardless, he had failed to raise disputed material factual issues sufficient to prevent summary judgment.

The appellate court's opinion was confined to the latter issue, stating that it was unnecessary to review the district court's conclusion regarding limitations because the evidence of factual issues cited by Turner was insufficient to constitute "evidence on which the [factfinder] could reasonably find for the plaintiff." *Id.* at 627 (alteration in original) (quoting *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 252 (1986)).

Turner did not appeal the district court's holdings against him on other issues discussed in this *Newsletter*'s previous report. Therefore, the district court's prior opinion in the case remains of value to the mineral bar.

Editor's Note: The reporter's law firm served as counsel for XTO Energy Inc. in *Turner v. XTO Energy Inc.* in both the district and circuit courts.

CALIFORNIA – OIL & GAS

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

California Governor Issues Directive to Halt Issuance of New Hydraulic Fracturing Permits in California by January 2024

In a September 23, 2020, executive order, Governor Gavin Newsom provided that California would work "to end the issuance of new hydraulic fracturing permits by 2024." Exec. Order N-79-20, at 2. As previously reported in Vol. XXXVII, No. 4 (2020) of this *Newsletter*, the order also tasked the California Department of Conservation's Geologic Energy Management Division (CalGEM) (formerly DOGGR) with proposing "a significantly strengthened, stringent, science-based health and safety draft rule that protects communities and workers from the impacts of oil extraction activities by December 31, 2020." *Id.* at 4. The timeline for CalGEM's draft public health regulations—which were initially intended to be released by December 2020 in compliance with the Governor's order—was extended to spring 2021. *See* CalGEM, "Draft Regulations Update" (Dec. 31, 2020).

While the administration previously has taken the position that it cannot ban hydraulic fracturing under current California law, *see* Rachel Becker & Laurel Rosenhall, "Newsom Orders Ban on New Oil Fracking by 2024," *Cal Matters* (Apr. 23, 2021), on April 23, 2021, in furtherance of his executive order, Governor Newsom expressly directed CalGEM to take regulatory action to halt the issuance of new fracking permits by January 2024. *See*

News Release, Office of Gov'r Gavin Newsom, "Governor Newsom Takes Action to Phase Out Oil Extraction in California" (Apr. 23, 2021). "Newsom's move comes a week after the Legislature rejected a bill that would have banned fracking." Becker & Rosenhall, *supra*. In compliance with the Governor's directive, CalGEM will immediately begin the rulemaking process to end the issuance of new permits by 2024. News Release, *supra*.

Also in connection with Governor Newsom's broad environmental goals as set forth in the executive order, the April 23 directive requested the California Air Resources Board to consider pathways to phase out oil extraction across California by 2045. *Id.*

The future of the April 23 directive may hinge on the results of a potential recall election. *See* "Gavin Newsom Recall, Governor of California (2019-2021)," *BallotPedia*, https://ballotpedia.org/Gavin_Newsom_recall,_Governor_of_California_(2019-2021).

Kern County Adoption of Revised Oil and Gas Permitting Ordinance Is Challenged in Court

As discussed in Vol. XXXVII, No. 2 (2020) of this *Newsletter*, the California Court of Appeal for the Fifth District set aside the Kern County (County) oil and gas permitting ordinance after identifying multiple deficiencies in the County's environmental review when the County adopted the ordinance. *See King & Gardiner Farms, LLC v. County of Kern*, 259 Cal. Rptr. 3d 109 (Ct. App. 2020). To correct these deficiencies, the County released a draft supplemental recirculated environmental impact report (SREIR) on October 30, 2020, and the final SREIR with response to comments was published January 29, 2021.

On March 8, 2021, the Kern County Board of Supervisors (Board) held a hearing in which it approved the project, and on March 9, 2021, the Board issued its notice of determination (NOD) certifying the SREIR and approving adoption of a revised ordinance directed at, among other things, correcting the deficiencies noted by the court of appeal (2021 Ordinance). The 2021 Ordinance became effective April 7, 2021. Kern County Code of Ordinances § 19.98.010. The revisions to the 2015 version of the ordinance "includ[e] creating larger buffers between homes and wells, muffling noise during drilling and putting a stricter limit on the number of new wells." Assoc. Press, "Kern County Approves Plan to Allow Thousands of New Oil Wells Despite Environmental Objections," *KTLA* (Mar. 8, 2021). "The 2015 ordinance would have allowed up to 72,000 wells, but with a lower cap on annual approvals, that number is now reduced to about 43,000 new wells in the 20-year period ending in 2035." *Id.*

Days after the Board issued its NOD, Committee for a Better Arvin, Committee for a Better Shafter, Comite Progreso de Lamont, Natural Resources Defense Council, Sierra Club, and Center for Biological Diversity (largely the same groups who filed the prior legal challenge) filed a lawsuit in the Kern County Superior Court. *See* Verified Petition for Writ of Mandate and Complaint for Injunctive Relief, *Comm. for a Better Arvin v. Cty. of Kern* (Cal. Super. Ct. Mar. 10, 2021). The action seeks to challenge the Board's approval of the 2021 Ordinance, asserting that the SREIR "largely failed to rectify the [California Environmental Quality Act (CEQA)] violations the Court of Appeal identified." *Id.* at 2. As such, according to the complaint, the SREIR fails to correct the errors identified by the court and otherwise fails to comply with CEQA.

The complaint asserts only one cause of action for violation of CEQA, but it asserts multiple grounds for that claim including (1) inadequacies in the SREIR, findings of fact, and statement of overriding considerations; (2) failure to comply with the court of appeal opinion; and (3) failure to provide meaningful opportunity for Spanish-speaking residents to participate.

By way of the complaint, the petitioners again seek to invalidate the Board's approval of the 2021 Ordinance, certification of the SREIR, and adoption of findings of fact and statement of overriding considerations. They additionally ask the court to direct the Board to set aside all permits reliant on the SREIR, and to enjoin future permit approval pending CEQA compliance. Finally, they ask the court to direct the County to publish future CEQA notices and executive summaries concerning the project in both Spanish and English.

CalGEM Sued for Alleged Unlawful Issuance of Oil and Gas Permits

On February 24, 2021, the Center for Biological Diversity (CBD) filed a lawsuit in Alameda County Superior Court against the California Geologic Energy Management Division (CalGEM) (formerly DOGGR) alleging that CalGEM is engaged in an unlawful pattern and practice of improperly issuing oil and gas permits and approvals across the state. *See* Complaint for Declaratory and Injunctive Relief, *Ctr. for Biological Diversity v. CalGEM* (Cal. Super. Ct. Feb. 24, 2021). CBD alleges that CalGEM has been issuing permits for drilling, well stimulation, and injection activities without the necessary environmental review. More specifically, the CBD complaint asserts that CalGEM issues permits and approvals in a way that skirts the requirements of the California Environmental Quality Act (CEQA) by doing one of the following: (1) issuing permits and approvals without any apparent environmental review documentation; (2) relying on inapplicable CEQA exemptions; or (3) issuing notices of determination that depend on inadequate or invalid environmental analyses performed by local governments.

The lawsuit claims CalGEM "ignor[es] its legal obligation to conduct environmental review before issuing oil and gas permits throughout the state." *Id.* at 2. According to the complaint, in 2020 alone, CalGEM approved at least 400 wells and 1 injection project with no CEQA documentation, 396 wells with an improper notice of exemption, and 1,265 wells and 83 well stimulation permits with an improper notice of determination. It further asserts that CalGEM skipped the public notice, comment, and hearing requirements that normally apply.

CBD seeks a declaration from the court that "CalGEM's pattern and practice of issuing oil and gas permits and approvals without applying the environmental review procedures under CEQA, and without determining whether its approval of such permits may have significant adverse environmental effects before making its determination, is unlawful." *Id.* at 26. It further seeks to enjoin CalGEM from continuing those practices "unless and until CalGEM complies with CEQA's environmental review procedures and adequately discloses, evaluates, and mitigates the direct, indirect, and cumulative impacts of each project." *Id.* at 27. Most recently, the Western States Petroleum Association filed a motion to intervene in the case, which motion was set to be heard on May 14, 2021.

IDAHO – MINING

Dylan Lawrence
– Reporter –

Idaho Updates Gyp-Stack Construction Standards

On April 16, 2021, Idaho Governor Brad Little signed into law new legislation updating standards for the construction of phosphogypsum stacks. *See* House Bill 239 (HB 239), 2021 Idaho Laws ch. 246. The previous standards were adopted by the Idaho Legislature in 2020. *See* 2020 Idaho Laws ch. 51, § 1. The updated standards are set to go into effect July 1, 2021.

Overall, the purpose of the state's recent legislative efforts to establish minimum design standards for "gyp-stacks" is to both protect human health and the environment and avoid case-by-case permitting of new stacks. *See generally* Idaho Code Ann. § 39-176A. Substantively, the primary focus of the new legislation is to provide more detailed standards for ponds, composite liners, leachate control systems, and perimeter dikes associated with gyp-stacks. *See* HB 239 §§ 3, 5 (provisions to be codified at Idaho Code Ann. §§ 39-176C(10), 39-176E(3)(a), (c), (4)). Provisions governing groundwater monitoring associated with gyp-stacks were omitted from the 2021 bill, which is focused on construction standards. *See* John O'Connell, "Conservationists Leery of New State Law Governing Construction of Mining Waste Rock Stacks," *Idaho State J.* (Apr. 21, 2021). Reportedly, groundwater monitoring will be the subject of future legislation. *Id.*

Gyp-stacks are common at phosphoric acid production facilities. Phosphogympsum is a byproduct in the production of phosphoric acid, which is a key ingredient in phosphate fertilizers. Due to its relatively low levels of radioactivity, phosphogypsum has been excluded from regulation as a hazardous waste under the Resource Conservation and Recovery Act, *see* 40 C.F.R. § 261.4(b)(7), and collecting the byproduct in gyp-stacks is a common industry process. While a gyp-stack incident in Florida has recently made national news, eastern Idaho contains one of the most productive phosphate regions in the world and is therefore home to multiple phosphoric acid production facilities.

LOUISIANA – OIL & GAS

Court VanTassell, Randee Iles & Kathryn Gonski
– Reporters –

Federal Fifth Circuit Says Louisiana Citizen Suit Can Proceed in Federal Court

In *Grace Ranch, L.L.C. v. BP America Production Co.*, 989 F.3d 301 (5th Cir. 2021), the U.S. Court of Appeals for the Fifth Circuit reversed a district court's decision to remand a land contamination lawsuit under the *Burford* abstention doctrine.

In this case, Grace Ranch L.L.C. (Grace Ranch) sued BP America Production Company (BP) and BHP Petroleum Americas (BHP) in state court, a second time, for alleged contamination of its property. After Grace Ranch's first claims for breach of contract and tort were dismissed pursuant to Louisiana's subsequent purchaser doctrine, this lawsuit was filed pursuant to the citizen suit provision of La. Rev. Stat. § 30:16. The statute allows a party in interest adversely affected by a violation of state conservation law to bring suit to prevent any further violations. Grace Ranch sought an injunction ordering the defendants to remediate the property. The defendants removed the case to federal court on diversity jurisdiction grounds given that Grace Ranch is a Louisiana company, and BP and BHP are citizens of Texas and Delaware. After determining that it had subject matter jurisdiction over the citizen suit claim, the district court elected to abstain under the *Burford* doctrine, which applies when federal court adjudication of claims may result in entanglement with state efforts to implement important policy programs.

The Fifth Circuit addressed three issues on appeal: (1) diversity jurisdiction, (2) appellate jurisdiction, and (3) *Burford* abstention. The court began with diversity jurisdiction. Grace Ranch argued that the State was a party to the lawsuit, pointing out that the section 30:16 lawsuit was a vehicle for enforcing the State's conservation law when the Commissioner of Conservation fails to act. The Fifth Circuit determined that the State was not a proper party because the statute does not authorize citizens to sue on the State's behalf. Rather, "[a] private party suing under section 30:16 does so on its own behalf." *Id.* at 309. Further, the court found that Louisiana was not a real party in interest to the lawsuit because the state only has a general interest in the outcome. Accordingly, because the State was "not a proper party or real party in interest," the court held that federal courts have subject matter jurisdiction over the claim. *Id.* at 310.

Next, the court considered whether it had appellate jurisdiction to review the district court's abstention ruling. While 28 U.S.C. § 1447(d) generally provides that "[a]n order remanding a case to the State court from which it was removed is not reviewable on appeal," only certain types of remand orders—those addressed by section 1447(c)—are subject to section 1447(d)'s prohibition. *Grace Ranch*, 989 F.3d at 311. The current version of section 1447(c) pertains to remands for lack of subject matter jurisdiction and remands for any non-jurisdictional defect. The court determined that a discretionary remand does not involve a "defect," thus the court had appellate jurisdiction to review the abstention ruling. *Id.* at 312–13.

After determining it had both subject matter and appellate jurisdiction over the case, the Fifth Circuit addressed the question of abstention, independently analyzing five factors previously crafted to determine whether *Burford* abstention is warranted. Because the case involved a state law claim that contained an unsettled question of state law in an area of importance to the State, three of the factors weighed in favor of abstention. However, the Fifth Circuit determined that this was not enough to refrain from exercising jurisdiction over the case. The court noted that federal courts frequently address questions of unsettled state law, and that federal resolution of the citizen suit claim would not disrupt Louisiana's efforts to establish a coherent policy for remediation of contaminated lands. Thus, the Fifth Circuit held that these claims "do not involve an integrated state regulatory scheme in which a federal court's tapping on one block in the Jenga tower might cause the whole thing to crumble." *Id.* at 319.

Editor's Note: The reporters and their colleagues represented BHP and BP in this case.

Louisiana's Good-Faith Purchaser Defense Protects Third-Party Purchaser of Oil in Subsurface Trespass Case

In *Hill v. TMR Exploration, Inc.*, 2020-0667 (La. App. 1 Cir. 1/27/21), 2021 WL 267916, the plaintiffs (collectively, Hills) brought a subsurface trespass action against TMR Exploration, Inc. (TMR) and its successor operators, alleging that TMR drilled a well on neighboring property that bottomed beneath the plaintiffs' land. Later, the Hills added claims against various Sunoco entities (collectively, Sunoco) that purchased oil from the well. Sunoco filed a motion for summary judgment to dismiss the claims against it based on the good-faith purchaser defense set forth in Louisiana Civil Code articles 521 through 524. In opposition, the Hills argued that the operators did not have the authority to sell the oil to Sunoco, thus, they could recover from Sunoco unless Sunoco was protected by section 31:210 of the Mineral Code. Section 31:210 protects third-party purchasers if they buy minerals produced from the last record owner of a recorded lease, as long as they have filed notice of purchase in the conveyance records of the parish where the lease is located. The Hills claimed that since Sunoco did not record notice that it was purchasing oil from the well, it was not entitled to the statutory protection. The district court granted the motion, dismissing all claims against Sunoco. *Hill*, 2021 WL 267916, at *1–2.

The Hills appealed to the Louisiana First Circuit Court of Appeal, arguing that the district court erroneously gave precedent to the Civil Code over the Mineral Code article. The First Circuit affirmed the district court's ruling, finding that the Mineral Code article was not applicable to the instant case. "The purpose and intent of La. R.S. 31:210 is to address rental and royalty payments due to parties holding an interest in the 'leased property' when a dispute or defect in the title exists." *Id.* at *6. The court stated that the Hills' claims, which were based on the alleged subsurface trespass, are "separate and distinct" from the recorded lease over the neighboring property. *Id.*

The court further noted that the Hills' argument would nevertheless fail because the Hills never owned the oil. Under Louisiana law, "oil and gas in place are fugitive minerals not subject to ownership by the owner of the land." *Id.* Thus, while a landowner has the right to drill for oil, he is not the owner of that oil until it is in his possession.

Potential Reformation Action Does Not Create Genuine Issue of Material Fact to Survive Summary Judgment

In *Covey Park Gas, LLC v. Bull Run Acquisitions II, LLC*, 53,670 (La. App. 2 Cir. 1/13/21), 310 So. 3d 777, *writ denied*, 2021-00235 (La. 4/7/21), 313 So. 3d 984 (mem.), the Louisiana Second Circuit Court of Appeal affirmed the lower court's summary judgment ruling, finding that a potential reformation action did not create a genuine issue of material fact.

In 2005, Naomi Brewer died, leaving her Louisiana assets, including mineral interests in three tracts of land in DeSoto Parish, to Bank of America as trustee for her heirs. The bank received a judgment of possession, which was filed in the succession proceeding; however, the judgment of possession was not filed in the conveyance records of DeSoto Parish. In 2008, Beaver River Resources (BRR) received an oil and gas deed that inadvertently included only one of the three tracts of land. Covey Park became the unit operator and drilled three wells on the tracts of land. In 2018, Bank of America realized the oil and gas deed described only one of the three tracts and sued to reopen the succession to distribute the remaining trust assets. The court rendered a judgment, which was filed in the conveyance records. Subsequently, Bull Run Acquisitions II, LLC (Bull Run) approached the beneficiaries and negotiated mineral deeds to buy all their interest in the two tracts of land. In February 2019, Bull Run sent a demand letter for royalties to Covey Park, which filed the concursus at issue. *Id.* at 779–80.

Bull Run filed a motion for partial summary judgment to dismiss BRR on the grounds that the oil and gas deed did not transfer any interest in the subject property, nor did it describe the property sufficiently to place third parties on notice. BRR argued that it and Bank of America intended to convey all three tracts, and that since the petition to close the succession and the judgment of possession described all three tracts, the discrepancy between those documents and the oil and gas deed should have put third parties on notice of the error. Further, BRR argued that the deed was subject to reformation, and that Bull Run would be bound by the reformed deed. The district court granted Bull Run's motion. *Id.* at 781.

On appeal, the Second Circuit first pointed out that reformation of instruments, a remedy to correct mistakes in an instrument to make express the true intentions of the parties, cannot be made to the prejudice of third parties who relied on the public records. *Id.* at 782. The Second Circuit stated that reforming the deed to include the two tracts of land "would obviously prejudice Bull Run, which relied on public records showing that the subject property belonged to somebody else, from whom it acquired title." *Id.* at 783. Additionally, because the deed was executed in 2008, the court found the action for reformation had prescribed. Reformation actions are subject to a 10-year liberative prescription, which begins to run when the party discovers or should have discovered the error. Because BRR argued that Bull Run should have noticed the error from the face of the oil and gas deed, the court determined that it was deficient enough to put BRR on notice of the error on the date of execution, thus prescription had run. *Id.*

Additionally, the court found that there was no recorded instrument with a property description sufficient to put third parties on notice of potential claims. "Third persons need only look to the appropriate mortgage or conveyance records to determine adverse claims." *Id.* at 784. Thus, the succession documents not filed in the conveyance record would not put a third party on notice. Finally, the Second Circuit refused to construe the oil and gas deed in a way to describe the subject property. While courts have reformed deeds with inaccurate descriptions by examining descriptive designations in the deeds, here there was "no reference to geographical features, constructions, exhibits or maps, or 'other descriptive designations.'" *Id.* at 785. The Second Circuit affirmed the summary judgment ruling, dismissing BRR as a claimant.

MINNESOTA – MINING

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

Minnesota Supreme Court Upholds Most of the Mining Permit for PolyMet's NorthMet Project

The Minnesota Supreme Court has reversed key parts of the 2020 decision of the Minnesota Court of Appeals vacating the permit to mine (PTM) and dam safety permits issued to Poly Met Mining, Inc. (PolyMet) for its NorthMet project. The supreme court, however, remanded the PTM back to the issuing agency for further review of one of the issues raised by opponents of the mine. *In re NorthMet Project*, No. A18-1952, 2021 WL 1652768 (Minn. Apr. 28, 2021), *aff'g in part, rev'g in part* 940 N.W.2d 216 (Minn. Ct. App. 2020); *see* Vol. XXXVII, No. 1 (2020) of this *Newsletter*.

The supreme court held that the court of appeals adopted an incorrect legal standard to review the Minnesota Department of Natural Resources' (DNR) decision denying the petitions for a contested case hearing on PolyMet's PTM application. Relying on the corrected standard of judicial review, the court upheld

DNR's decision denying the hearing requests for four groups of permit issues but found that for a fifth one a contested case hearing was required. In addition, the court affirmed that state law requires DNR to issue the PTM for a fixed term rather than the more flexible, performance-based approach previously established by the agency.

The court disagreed with much of the court of appeals' reasoning on the contested case. The lower court had ruled that because the project opponents (Respondents) raised factual disputes concerning five groups of issues embedded in the PTM, the contested case provision of the state's mining law, Minn. Stat. § 93.483, mandated that DNR hold an evidentiary hearing on those issues before deciding whether to issue the permit. The court of appeals rejected DNR's arguments that the Respondents lacked standing to seek a contested case and that the agency retained discretion under the state statute to determine whether a contested case should be held. The lower court also determined that, because the underlying factual issues were applicable to both the PTM and the separate dam safety permits issued by DNR, the contested case hearing on remand must address all these permits.

The supreme court rejected most of the court of appeals' construction of section 93.483 and generally agreed with the arguments advanced by DNR and PolyMet. (The supreme court agreed with the court of appeals that the Respondents had standing under section 93.483, subd. 1, to petition for a contested case hearing, and that DNR's contrary interpretation of the statute was in error. *In re NorthMet Project*, 2021 WL 1652768, at *7.) In particular, the court held that "DNR has the discretion to determine whether a hearing on the factual disputes in a petition for a contested case hearing will 'aid' the agency in making a final decision on the completed [PTM] application." *Id.* at *11. The relevant statutory provision requires a contested case hearing if three criteria are met: (1) there is a disputed material issue of fact, (2) DNR has jurisdiction to resolve the dispute, and (3) a contested case hearing would provide information "that would aid the [agency's] commissioner in resolving the disputed facts." *Id.* at *8 (quoting Minn. Stat. § 93.483, subd. 3(a)). The supreme court's decision turned principally on the third requirement. The lower court had found that the contested case statute did not confer such discretion on the agency.

The supreme court further concluded the conventional standard of review under the Minnesota Administrative Procedure Act governs judicial review of DNR's decisions as to whether to conduct a contested case hearing. *Id.* at *11 (citing Minn. Stat. § 14.69, which provides that the standard for judicial review is whether an agency's factual findings are unsupported by substantial evidence, arbitrary or capricious, or affected by an error of law).

Applying the foregoing principles, the supreme court found substantial evidence in the administrative record to support DNR's determinations that no contested case hearing was required on most of the factual disputes raised by the Respondents. The court emphasized that the record, which included hundreds of thousands of documents, showed that DNR considered various objections raised by the Respondents, evaluated relevant alternatives and trade-offs, and reached reasonable conclusions based on adequate evidence. *Id.* at *12–14. The supreme court rejected certain other arguments raised by the Respondents for lack of jurisdiction due to lack of timeliness and other non-substantive considerations. *Id.* at *16–17. The court also held that these administrative actions by the agency were entitled to judicial deference. *Id.* at *18.

But concerning one issue—whether certain proposed uses of bentonite in the tailings basin over the life of the mine would be effective for their intended purposes—the supreme court found that DNR's decision did not meet the substantial evidence standard. (The Respondents raised three distinct bentonite issues, but the supreme court ruled in their favor on only one of the three objections.) The Respondents introduced a variety of evidence during the permitting process challenging the effectiveness of the proposed bentonite uses. While the court noted certain documents in the record discussed the proposed bentonite uses, it concluded that they provided "no analysis of the scientific basis for the DNR's assumptions" and DNR did not include within the administrative record the study it relied on to support its decision. *Id.* at *14. (The opinion does not explain why this study was not included in the administrative record.) In other words, while the agency receives the benefit of deference and need only show consideration of substantial evidence, the court found that this requires that some evidence be included in the administrative record. Further, the court found the PTM conditions requiring PolyMet, after permit issuance and before construction, to prove the effectiveness of the bentonite uses were not a sufficient substitute for more robust record evidence at the permit issuance stage. *Id.* at *15.

The Respondents asserted that two events occurred after DNR's issuance of the PTM in 2018 that warrant further examination in a contested case proceeding: one allegedly relevant to the design of the tailings basin dams and the other to financial assurance. The court of appeals took judicial notice of these events, which were outside of the administrative record, and agreed with the Respondents that the issues should be considered in the contested case hearing. The supreme court disagreed. The court noted with respect to each post-decision event that DNR has authority and procedures to modify permits if the facts merited substantive attention. *See id.* at *12 n.15, *16 n.21. This approach avoids the impractical outcome of never defining the endpoint in a permitting process.

The supreme court affirmed the court of appeals' determination that DNR erred as a matter of law in including an indefinite, performance-based term (e.g., completion of certain reclamation activities) in the PTM. *Id.* at *18. The supreme court agreed that Minn. Stat. ch. 93 and the applicable regulations require a permit term of a fixed, calendar-based duration. *Id.* at *19. This determination is significant as mining companies often expect to operate for decades, and DNR had previously issued a single PTM to govern the entire life of mine, subject to amendments and appropriate environmental review and permitting under other programs.

Finally, the supreme court overturned the lower court's ruling with respect to the two dam safety permits issued by DNR. The court of appeals had reversed DNR's decision without evaluating whether there was substantial evidence supporting the dam safety permits or whether there were any legal deficiencies in the permits. Instead, the lower court found the reversal was necessary because DNR had explained there was substantial overlap in the factual matters and administrative processes concerning the dam safety permits and the PTM. The supreme court rejected this analysis, finding the court of appeals acted prematurely in presuming the PTM contested case hearing would affect the validity of the dam safety permits. *Id.* at *19. Noting the different statutory standards applicable to the two types of permits, the court observed that the contested case hearing on the PTM may not affect the dam safety permits but, if it does, DNR has discretion to modify the dam safety permits. *Id.* at *20 (citing Minn. R. 6115.0500(B)).

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

Minnesota Supreme Court Reverses Remand of Air Permit for NorthMet Project

In another in the series of cases involving permits issued for the NorthMet mining project in 2018 and 2019, the Minnesota Supreme Court in February 2021 reversed the decision of Minnesota Court of Appeals remanding the air emissions control permit back to the Minnesota Pollution Control Agency (MPCA) for further review and fact finding. *See In re Air Emissions Permit No. 13700345-101 for PolyMet Mining, Inc.*, 955 N.W.2d 258 (Minn. 2021), *rev'g* 943 N.W.2d 399 (Minn. Ct. App. 2020). MPCA issued a synthetic minor air permit to Poly Met Mining, Inc. (PolyMet) in 2018 for the proposed mine, and the respondents—a coalition of environmental groups and the Fond du Lac Band of Lake Superior Chippewa—alleged in their appeals that the agency failed to adequately consider whether the company may expand its operations in the near future, making it subject to more stringent emissions limitations. The respondents claimed PolyMet was engaged in "sham permitting."

The respondents grounded their arguments primarily in certain regulations and guidance from the U.S. Environmental Protection Agency that they alleged required investigation of whether PolyMet intended to exceed operational limits included in its synthetic minor air permit. The court of appeals agreed with this interpretation of federal requirements under the Clean Air Act, and found that MPCA failed to make sufficient factual findings with respect to the required investigation, focusing in particular on the potential for the company to expand in the near future so as to produce emissions beyond the permitted levels. *See* Vol. XXXVII, No. 2 (2020) of this *Newsletter*.

The supreme court reversed, holding that the court of appeals incorrectly interpreted federal law. Specifically, the supreme court held that MPCA "was under no federal obligation to investigate sham permitting during the synthetic minor source permit process." *In re PolyMet Air Permit*, 955 N.W.2d at 268. The supreme court remanded the matter back to the court of appeals to address certain other arguments advanced by the respondents that were not grounded in the federal requirements on which the court of appeals had relied. *Id.* at 269. Based on the court of appeals' scheduling order, its decision on the remand is expected later this summer.

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

MISSISSIPPI – OIL & GAS

W. Eric West
– Reporter –

Mineral Interest Owners Must Exhaust All Administrative Remedies Before the Oil and Gas Board

In *Darville v. Germany*, No. 5:20-cv-00180 (S.D. Miss. Mar. 1, 2021), Robert H. Darville and wife Joe Ann Crawford Darville as well as other plaintiffs filed suit alleging that they are the owners of undivided royalty and mineral interests in oil and gas production in the McComb Field Unit, a compulsory unitized field in Pike County, Mississippi.

The parties do not dispute that one of the unit's unitized intervals, the "C" sand, was not included in the tract participation factors in a Mississippi State Oil and Gas Board (Board) order issued in 1998 but was purposefully excluded by agreement of the parties. In Mississippi, compulsory unitization determines the interests of all parties in accounting for 100% of production through unit tract participation factors.

Defendant Denbury Onshore LLC (Denbury), the current operator of the unit, has been operator almost from its inception in 1998. The 1998 order provides

> tract factors for tract participation in the 259 tracts within the McComb Field Unit are based upon "A" and "B" sands only with no credit given for the "C" sand. In the event operator of the McComb Field Unit achieves any production from the "C" sand . . . in the future, operator of the McComb Field Unit will recalculate all unit tract participation factors to include credit for the "C" sand. No credit is given for the "C" sand at this time because there is no production planned at the present time from the "C" sand.

Darville, slip op. at 2 n.1.

The plaintiffs claim that Denbury began producing oil from the "C" sand in April 2006 and failed to reallocate the tract factors in violation of the 1998 order. Then, 14 years later (May 4, 2020) the plaintiffs filed suit against the defendants in the Circuit Court of Pike County, Mississippi, alleging "breach of contract, liability for statutory interest on royalty proceeds, fraud and misrepresentation, conversion, wrongful taking and concealment, civil conspiracy, breach of the duty of good faith and fair dealing, joint and several liability, fraudulent concealment, and punitive damages." *Id.* at 3. On September 14, 2020, Denbury removed the matter to the U.S. District Court for the Southern District of Mississippi, Western Division. *Id.* On December 8, 2020, Denbury filed a petition with the Board (Docket No. 3-2021-D) to establish recalculated unit tract participation factors for the "C" sand oil pools. *Id.* Denbury filed a motion to dismiss/stay in the district court on that same day. All the defendants, other than Denbury, were dismissed from the case in January 2021.

On March 1, 2021, the district court entered an order staying the action in its entirety pending the ruling of the Board on Denbury's petition and the exhaustion of all administrative remedies before the Board. *Id.* at 9. The court, following prior state and federal court precedent, found that the plaintiffs are required to present their grievances to the Board before pursuing state law damage claims, which are beyond the Board's power to grant, in this court. *Id.* at 6–7 (citing *Miller v. Miss. Res., LLC*, No. 5:17-cv-00041, 2018 WL 934827, at *2 (S.D. Miss. Feb. 16, 2018); *Howard v. TotalFina E&P USA, Inc.*, 899 So. 2d 882, 888 (Miss. 2005); *Town of Bolton v. Chevron Oil Co.*, 919 So. 2d 1101, 1107–08 (Miss. Ct. App. 2005)).

Finally, the court found that no exception to the doctrine of administrative exhaustion is present that would excuse the plaintiffs from first pursuing to conclusion their remedies at the Board. In deciding if it should excuse the plaintiffs' failure to exhaust, the court considered whether "(1) pursing an administrative remedy would cause irreparable harm; (2) the Board 'clearly' lacks jurisdiction; (3) the Board's position is illegal; (4) a legal issue is dispositive; (5) exhaustion would be futile; and (6) the suit is more efficiently resolved in this court." *Id.* at 7 (citing *Miller*, 2018 WL 934827, at *2–3; *Pub. Emps. Ret. Sys. of Miss. v. Hawkins*, 781 So. 2d 899, 906 (Miss. 2001) (per curiam)).

Editor's Note: The reporter represented defendants that were dismissed prior to the court's ruling.

OHIO – MINING / OIL & GAS

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

Supreme Court of Ohio Further Clarifies the "General vs. Specific" Exception to the Ohio Marketable Title Act

The Ohio Marketable Title Act (MTA), Ohio Rev. Code §§ 5301.47–.55, provides that an unbroken chain of title to land for a period of 40 years establishes marketable record title to the land, which generally extinguishes property interests that predate the landowner's root of title. *Id.* §§ 5301.47(A), .48. However, the MTA is subject to certain exceptions, including those referenced in section 5301.49. Section 5301.49(A) provides that marketable record title is subject to all "interests and defects" inherent in the muniments of the chain of title, with the exception that "a general reference . . . to easements, use restrictions, or other interests created prior to the root of title" is not sufficient to preserve such an interest from being extinguished unless the general reference also includes "specific identification" of the recorded title transaction that created the interest. In *Erickson v. Morrison*, 2021-Ohio-746, the Supreme Court of Ohio clarified that for a reference in a chain of title to be "specific" (preventing application of the MTA), it need not reference the name of the interest owner.

Erickson relates to a property in Guernsey County, Ohio, that was conveyed by James T. and Rose L. Logan to Edward and Alta Riggs in February 1926. *Id.* ¶ 5. There, the Logans conveyed the property to the Riggs by deed that contained following language: "Excepting and reserving therefrom all coal, gas, and oil with the right of said first parties, their heirs and assigns, at any time to drill and operate for oil and gas and to mine all coal." *Id.* After severance of the oil and gas, the surface was conveyed five times through recorded instruments between 1926 and 1975. *Id.* ¶ 6. On May 1, 1978, a deed was recorded conveying the surface to Paul E. and Vesta G. Morrison. *Id.* ¶ 7. Each conveyance contained severance language that was nearly identical to that contained in the February 1926 severance deed. *Id.* ¶¶ 6–7.

On August 24, 2017, the successors-in-interest to the Riggs (W. Randall and Kathleen Erickson) filed a complaint in the Guernsey County Court of Common Pleas against the Morrisons claiming that they owned the mineral rights by virtue of the February 1926 severance deed. *Id.* ¶ 8. The trial court granted judgment on the pleadings in their favor, which was reversed on appeal due to the application of the MTA. *Id.* ¶¶ 9–10. On appeal to the supreme court, the Ericksons claimed that neither section 5301.49 nor Ohio case law requires a reference in a chain of title to the interest owner's name to be specific. *Id.* ¶ 12. Conversely, the Morrisons claimed that the supreme court's holding in *Blackstone v. Moore*, 2018-Ohio-4959, 122 N.E.3d 132, indicated that if the reference does not name the volume and page of the instrument where the severance occurred, it must include both the type of interest created and the name of its owner. *Erickson*, 2021-Ohio-746, ¶ 13.

The supreme court reviewed the three-step analysis it originally established in *Blackstone*. Namely, "(1) Is there an interest described within the chain of title? (2) If so, is the reference to that interest a 'general reference'? (3) If the answers to the first two questions are yes, does the general reference contain a specific identification of a recorded title transaction?" *Id.* ¶ 18. After affirmatively answering the first inquiry, the court held that the references to the severance in the surface owners' chain of title were sufficiently specific because the references in those deeds were not vague references to prior reservations that may or may not exist. *Id.* ¶ 32. "Rather, the [surface owners'] root of title and subsequent conveyances are made subject to a specific, identifiable reservation of mineral rights recited throughout their chain of title using the same language as the recorded title transaction that created it." *Id.* Because the court also answered the second inquiry affirmatively, it did not need to reach a decision on the third.

The supreme court's decision in *Erickson* appears to indicate that when a chain of title repeats language creating a severance of oil and gas, the reference will be sufficiently specific to prevent application of the MTA. The court specifically limited its holding to provide that a reference to a severance of oil and gas need not include the name of the owner of the severed interest to prevent application of the MTA. *Id.* ¶ 14. However, another thing is clear from the *Erickson* decision—the application of the MTA is fact specific and will need to be reviewed by oil and gas companies and practitioners on a case-by-case basis.

OKLAHOMA – OIL & GAS

James C.T. Hardwick – Reporter –

Operations on One Unit of a Multi-Unit Horizontal Well Satisfy Commencement of Operations on the Adjacent Unit

In the case of *Lawson v. Citizen Energy II, LLC*, 2021 OK CIV APP 1, 481 P.3d 287, the question was whether commencement of drilling operations on one of two units for a multi-unit horizontal well served to extend a lease on an adjacent unit where the well did not penetrate the adjacent unit until after the end of the primary term. The plaintiffs were lessors under an oil and gas lease (the "Lawson Lease") located in Section 11 comprising a 640-acre drilling and spacing unit. That unit was adjacent to a separate 640-acre drilling spacing unit for Section 14 immediately south of Section 11. The Oklahoma Corporation Commission (OCC) granted to the lessee operator an application for a multi-unit horizontal well with a completion interval in both Section 11 and Section 14. The operator commenced to drill a well from a surface location in Section 14 with the intent of drilling a horizontal lateral north into Section 11. Operations were commenced on Section 14 before the expiration of the Lawson Lease. However, the lateral did not penetrate the Section 11 unit until after expiration of the primary term of the Lawson Lease. The parties dispute whether these operations in Section 14 satisfy the commencement clause in the Lawson Lease.

The plaintiffs argued that the Lawson Lease required that commencement of the well occur on Section 11 within the term of the lease. The operator argued that physical entry on Section 11 was not required but that commencement of drilling on Section 14 was sufficient to extend the Section 11 lease. The commencement clause of the Lawson Lease provided that if the lessee commenced to drill a well within the term of the lease, the lessee had the right to drill such well to completion, and if oil and gas were found in paying quantities, the lease would be extended just as if the well had been completed within the primary term of the lease. The court said the core issue here was whether commencement of operations on Section 14 satisfied the commencement clause of the Lawson Lease.

The court noted that historical drilling and spacing unit rules may not have kept pace with advances made in drilling technologies, especially extended length laterals used in horizontal drilling. *Id.* ¶ 12. The court examined the Extended Horizontal Well Development Act, Okla. Stat. tit. 52, §§ 87.6–.9, which provides that "[a] multiunit horizontal well shall be treated as a well in each of the affected units and shall be subject to all of the rules otherwise applicable to any other well in any of the affected units." *Id.* § 87.8(B)(3) The court noted that the Act requires the application to drill to "include the anticipated location of the proposed multi-unit horizontal well to be drilled in each affected unit and directs how to calculate costs, production, and proceeds based on the allocation factor after completion." *Lawson*, 2021 OK CIV APP 1, ¶ 13. The court concluded that the term "affected unit" contemplated "a unit included in a multi-unit horizontal well application and those units actually penetrated within the completion interval of the well." *Id.*

Here, the application proposes to drill a horizontal well with an extended length lateral to underlie both Section 11 and Section 14 and requests the OCC to allocate costs, commingled production, and proceeds based on the respective length of the lateral in each section. *Id.* ¶ 14. Thus, Sections 11 and 14 are "affected" sections. *Id.* "Therefore, a multi-unit horizontal well drilled in the Section 14 unit is treated as a well in the Section 11 unit." *Id.* The court concluded that "[c]ommencement operations in the Section 14 unit during the Lease's primary term extended the Lease as a matter of law, provided the well so commenced is completed as a producing well." *Id.*

Size of Corporation Commission Unit for Horizontal Oil Well Supersedes Acreage Limitation in Voluntary Pooling Clause

In *Cory v. Cimarex Energy Co.*, No. 5:20-cv-00706, 2021 WL 1108596 (W.D. Okla. Mar. 23, 2021), the plaintiffs were successors-in-interest to the original lessors in an oil and gas lease covering an 80-acre tract in Section 25, T15N, R9W, Kingfisher County, Oklahoma, and the defendant, Cimarex Energy Co. (Cimarex), was successor-in-interest to the original lessee. The lease contained the typical voluntary pooling clause permitting the lessee, at its option, the right to pool acreage into units not exceeding 160 acres for an oil well and 640 acres for a gas well. In July 2015, the Oklahoma Corporation Commission (OCC) entered an order establishing Section 25 as a 640-acre horizontal well unit for the Mississippian common source of supply. Pursuant to that order, Cimarex completed the Loretta 1-25H well, a horizontal oil well within the unit. The plaintiffs filed suit in July 2020 against Cimarex for breach of contract, conversion, and declaratory judgment.

The plaintiffs' three claims were predicated upon the allegation that Cimarex violated the lease's 160-acre pooling restriction by drilling the Loretta well as an oil well on a 640-acre unit that includes the lease in question. Cimarex argued that the 160-acre pooling restriction was superseded by the OCC's spacing order and therefore the plaintiffs' claims fail as a matter of law.

Addressing the breach of contract claim, the court said "Cimarex's duty to comply with the Lease's 160-acre pooling restriction hinges on the intent of the original contracting parties." *Id.* at *2. Cimarex relied on the cases of *Hladik v. Lee*, 514 P.2d 196 (Okla. 1975) and *Oklahoma Natural Gas Co. v. Long*, 406 P.2d 499 (Okla. 1965). In *Hladik*, the oil and gas lessee had pooled 10 separate tracts to create a 480-acre declared unit. Subsequently, the OCC issued a spacing order creating a 160-acre compulsory spacing unit within the acreage comprising the declared unit. The issue was how to distribute royalties on production from the compulsory unit. The Oklahoma Supreme Court declared that the compulsory unit superseded the declared unit and that royalties should be paid only to those lessors whose acreage was within the 160-acre compulsory unit. "The court reasoned that oil and gas leases are negotiated against the backdrop of the OCC's regulatory authority," and in the absence of an express agreement to the contrary, it is to be assumed that "the parties intended that a valid exercise of such authority would supersede any and all conflicting lease provisions." *Cory*, 2021 WL 1108596, at *2.

The issue in *Long* was whether the lease in question had been perpetuated by the drilling of a well within the primary term of the lease. Subsequent to the lease's execution the OCC created a 640-acre spacing unit that covered the leased property and a well was drilled on the unit but not on the lease in question. The lessor argued that the lease expired by its own terms because there was no well drilled on that lease. Likewise, the court reasoned that when the lease was entered into, the parties knew of the OCC's authority to enact well spacing regulations in the furtherance of conserving oil and gas and they contracted subject thereto. "The court held that the spacing order superseded the conflicting lease provision and, therefore, production from the well operated to perpetuate the lease." *Id.*

The court in this case agreed with Cimarex that *Hladik* and *Long* foreclosed the plaintiffs' breach of contract claim, saying that these cases "teach that the OCC's regulatory authority, e.g., to space wells for the conservation of oil, gas, and other natural resources, is 'incorporated in[to]' private oil and gas leases 'by operation of law.'" *Id.* at *3 (alteration in original) (quoting *Long*, 406 P.2d at 504). "It is therefore the expectation and intention of the contracting parties that a valid exercise of the OCC's regulatory authority will supersede conflicting lease provisions of the kind at issue here." *Id.* The court also reviewed and rejected the plaintiffs' attempt to distinguish *Hladik* and *Long* from the current case. *Id.*

The court next observed that the plaintiffs' claims for conversion and declaratory judgment were predicated upon a finding that Cimarex had drilled the Loretta well in violation of the lease. The breach of contract claim having failed, the court granted Cimarex's motion to dismiss. *Id.*

The reader is referred to this reporter's report on the case of *Cory v. Newfield Exploration Mid-Continent, Inc.*, No. 5:19-cv-00221, 2020 WL 981718 (W.D. Okla. Feb. 28, 2020), in Vol. XXXVII, No. 3 (2020) of this *Newsletter*, involving the same plaintiff with the same claims as this case presented to the same judge but with the court ruling for the plaintiff in that case. The difference in outcome between the earlier case and the current case may be explained by the difference in legal authorities relied upon by the defendant in this case.

The court's analysis begins with an assumption that the intent of the parties to the lease was that the exercise of the OCC's regulatory authority establishing the spacing order at issue would supersede any conflicting lease provision. Moreover, the court limited its intent statement to the absence of an express agreement to the contrary. This reporter believes that the issue of intent is unnecessary and potentially misleading. The OCC's establishment of drilling and spacing units is an exercise of authority conferred on the OCC by the legislature to prevent waste and protect correlative rights. *See Union Oil Co. of Cal. v. Brown*, 641 P.2d 1106, 1109 (Okla. 1981); *Samson Res. Co. v. OCC*, 859 P.2d 1118, 1122 (Okla. 1993). That authority, in turn, is derived from the police power of the state. As a consequence, "[t]he right of the Legislature to act under the police power of the state is a part of the existing law at the time of the execution of every contract, and as such becomes in contemplation of law a part of that contract." *Layton v. Pan Am. Petroleum Corp.*, 383 P.2d 624 (Okla. 1963), Syl. No. 2; *Sunray DX Oil Co. v. Cole*, 461 P.2d 305, 309 (Okla. 1967). Thus, intent of the parties is not required for a spacing order to supersede a contrary lease provision.

Proper Attorney's Fee Award in Royalty Class Action Settlements

Strack v. Continental Resources, Inc., 2021 OK 21, was a class action brought on behalf of 33,890 Oklahoma royalty owners for underpayment of oil and gas royalties. After seven years of litigation without trial, the parties entered into a settlement agreement approved by the district court requiring Continental Resources, Inc., to pay an estimated $57.3 million into a common fund. The settlement agreement provided for an attorney's fee of $19 million based on a 40% contingency fee. It also included a $400,000 incentive award to two of the class representatives ($200,000 each). A member of the class, Daniel McClure, who is also a Houston class action defense attorney, objected to both the award of attorney's fees and the incentive award. The Oklahoma Court of Civil Appeals reversed the trial court and the Oklahoma Supreme Court accepted certiorari.

The court first considered whether Oklahoma's class action attorney's fee statute, Okla. Stat. tit. 12, § 2023(G), allowed for a percentage of common fund method of calculating attorney's fees. The court decided that it did. However, the court concluded that it also allowed for attorney's fees to be calculated on the lodestar method. *Strack*, 2021 OK 21, ¶¶ 13–19. In considering the fee award here, the court stated that "the class representatives and class counsel must act in a fiduciary relationship on behalf of the silent class members . . . ." *Id.* ¶ 2. Furthermore, the statute also places the district court in a fiduciary role to the class when awarding attorney's fees. *Id.* The court concluded that "the district court failed to consider this role to the royalty owners . . . to ensure that not only class counsel but also the royalty owners benefited from this litigation." *Id.*

The attorney's fee statute identifies a number of factors to be considered, such as actual time spent, difficulty involved, skill necessary, the amount in controversy, and the results obtained. The court observed that although the statute does not mandate either the lodestar or percentage method, it also does not foreclose either but instead suggests that both are appropriate. *Id.* ¶ 17. More important, "[t]he goal in [an] attorney fee case is not to select a methodology but to arrive at a reasonable fee." *Id.* ¶ 18. The court concluded that, to ensure reasonableness of the fee in common fund class actions, it was necessary to compare a percentage fee calculation to a calculation by the lodestar approach. *Id.* ¶ 19.

The court noted that while a 40% contingency fee may be normal in an individual litigation, in complex class actions, attorney's fees awards are normally in the range of 20% to 30% of the recovery. *Id.* ¶ 22. It concluded that an award of 40% was excessive compared to the average of 20% to 30% found in class action litigation. *Id.* The court stated that this fee award was particularly excessive when compared to the amount the class counsel would receive under the lodestar method. *Id.* ¶ 23. The class counsel argued that under the lodestar method, the attorney's fees would be $6,288,831 and with an enhancement factor of 317% it would yield approximately the same result as the 40% of the common fund calculation. *Id.* ¶ 6. The court said that "[t]he lodestar method may be more suitable in cases like this one where the percentage method based on class counsel's contingency agreement produces an excessive fee award." *Id.* ¶ 25. However, the only support for a 317% lodestar enhancement was a mere conclusory statement from an expert witness. *Id.* ¶ 29. Further, even from an expert witness, there was no basis in law or the facts to allow such a 317% enhancement factor. *Id.* ¶ 30. Other cases the court examined revealed an enhancement multiplier of somewhere around 1.4 (40%). *Id.* The court concluded that the district court had used a 317% enhancement multiplier based on nothing more than an attempt to equate it to the 40% common fund, unsupported by any evidence, and was an abuse of discretion. *Id.* ¶ 31.

As for the $400,000 incentive award, the court stated that an incentive award could be justified as "payment for reasonable services rendered by class representatives on behalf of the class that were helpful to the litigation." *Id.* ¶ 33. However, it must be supported by sufficient evidence in the record. *Id.* Here, the district court's award was devoid of any evidence as to how that computation was made, and it was not based on actual work performed. *Id.* ¶ 35.

The court also considered McClure's objection that he had never been permitted access to the detailed billing records of the plaintiffs' counsel and that those records had never been subjected to an adversarial contest at the evidentiary hearing. The court again noted that "[t]he district court had a fiduciary duty [to the class] to give full adversarial scrutiny to the attorney's fees requested . . . ." *Id.* ¶ 37. Instead the district court deprived McClure, standing in the shoes of the other class members, that opportunity to review or meaningfully challenge the very fees he and other class members were required to pay from their own royalty interest. *Id.* This also was an abuse of discretion. *Id.*

The supreme court remanded the case for proceedings consistent with its opinion. *Id.* ¶ 40.

Oil and Gas Owners' Lien Act of 2010 Does Not Secure the Payment of an Unpaid Pooling Order Bonus

This is the decision on the plan administrator's objection to the secured status of the proof of claim of Triumph Energy Partners (Triumph) filed in *In re Alta Mesa Resources, Inc.*, No. 4:19-bk-35133, 2021 WL 1731774 (Bankr. S.D. Tex. Apr. 27, 2021). Triumph's claim arose from the failure of Oklahoma Energy Acquisitions (OEA), a debtor in the Alta Mesa bankruptcy proceedings, to pay a bonus due under an Oklahoma Corporation Commission pooling order. Triumph owned working interests in various leases included in a 640-acre horizontal well unit of which OEA was designated operator. Following OEA's notice of intent to drill three additional wells, Triumph declined to participate but instead exercised its rights under a pooling order to receive a cash bonus of $330,000 in return for the transfer to OEA of Triumph's working interest. OEA never completed the wells and never produced oil or gas from them. The bonus was unpaid and outstanding at the time of Alta Mesa/OEA filing bankruptcy. Triumph asserted a $330,000 secured claim against the debtors, claiming rights under the Oklahoma Oil and Gas Owners' Lien Act of 2010 (Lien Act), Okla. Stat. tit. 52, §§ 549.1–.12. The plan administrator objected to the secured status of Triumph's proof of claim.

The Lien Act was enacted in 2010 to cure defects found in Oklahoma's prior lien act by the Delaware bankruptcy court in *In re SemCrude, L.P.*, 407 B.R. 112 (Bankr. D. Del. 2009). The bankruptcy judge in the current case pointed out that "the purpose of the statute was to give Oklahoma producers and royalty owners a first-priority lien to secure payment for their interest in oil and gas sold to a first purchaser." *In re Alta Mesa*, 2021 WL 1731774, at *3 (quoting *Gaskins v. Texon, LP*, 321 P.3d 985, 990 (Okla. Civ. App. 2013)). The judge acknowledged that Triumph was an interest owner under the Lien Act and would have a lien to secure the obligations of a first purchaser to pay the sales price for oil and gas sold. However, the judge stated that "a lien '[t]o secure the obligations of a first purchaser to pay the sales price,' is not the same as a lien to secure any amounts owed to Triumph on account of Triumph's oil and gas rights." *Id.* (alteration in original) (quoting Okla. Stat. tit. 52, § 549.3(A)). Here, the dispute related to the non-payment of the opt-out pooling bonus. "There was never a first purchaser because there was never any production from the proposed new wells. . . . [T]he bonus arose from Triumph's decision to *opt out* of its interests in [drilling additional] wells." *Id.*

Triumph argued that the Lien Act expressly attaches to oil and gas prior to extraction, follows the oil and gas upon severance, and attaches to the proceeds of sale. *Id.* at *4 (citing Okla. Stat. tit. 52, § 549.3). Thus, claimed Triumph, its lien attached to OEA's assets, even though the new wells never produced oil and gas. *Id.* The court responded that "[w]hile the lien may attach to oil and gas prior to severance from the ground, the [Lien Act] makes clear that the lien only exists 'to secure the obligations of a first purchaser to pay the sales price.'" *Id.* (quoting Okla. Stat. tit. 52, § 549.3(A)). As such, "[t]he Lien Act does not grant Triumph a free-wheeling lien to secure any and all amounts owed." *Id.* The court concluded that Triumph could not look to the Lien Act "to ensure payment of amounts that are not obligations of a first purchaser." *Id.* Secured status for the claim was denied. *Id.*

Jury Verdict in Favor of Producers Against Royalty Owners Claiming Unlawful Deduction of Costs in Computing Royalties Sustained on Appeal

In the case of *Slatten v. Range Resources Corp.*, No. 118,171 (Okla. Civ. App. Mar. 3, 2021) (unpublished), the plaintiffs appealed from a judgment entered on a jury verdict in favor of the defendants rejecting the plaintiffs' claims that the defendants improperly computed royalties paid the class. The plaintiffs were oil and gas lessors and the defendants were lessees/producers. The plaintiffs claim the defendants underpaid royalties due by unlawfully deducting costs that should have been borne by the defendants. The costs at issue were midstream services such as gathering costs, compression, and dehydrating that the plaintiffs claim were costs incurred to render the raw gas marketable and therefore required to be borne by the defendants. The plaintiffs also claim the defendants did not pay royalties on gas used as fuel to perform midstream services and failed to pay royalties on condensate that dropped out of the raw gas stream. The plaintiffs asserted that there was no market for raw gas at or near the wells and that the defendants' sales of raw gas to midstream companies did not constitute a market.

The defendants claim they paid royalties without deductions. The defendants sold the raw gas to midstream companies that were not affiliated with the defendants. Title to the gas passed to the midstream companies at the point of sale, and the defendants had no role in the decisions regarding processing and marketing of the gas by the midstream companies after taking title to the gas. The defendants claim the gas was a marketable product at the point of sale to the midstream companies, and that the price paid by the midstream companies was an arm's-length, negotiated price based upon a formula that was a percentage of that received by the midstream companies. The defendants did not dispute that they cannot deduct processing and related costs, but claim they did not do so and that they paid royalties on the total sum that they received without deductions. The defendants presented evidence to support their position that there was a market at the point of sale to the midstream companies.

The plaintiffs presented evidence, including expert testimony, regarding markets and their claim that the contracts between the defendants and the midstream companies were not sales contracts but service contracts. In doing so, the plaintiffs placed the market at the tailgate of the midstream companies' plants and maintained that the gas was not marketable until processed by the midstream companies. The plaintiffs asserted that the defendants' midstream contracts were either service contracts or contracts that violated the defendants' duties to royalty owners related to marketing the gas.

The trial court gave jury instructions on the elements of a contract, the gross value of the production at the well, and the lessee's duty to create a marketable product, and that percentage of proceeds contracts do not reduce the amount of royalties due. The jury returned a unanimous verdict in favor of the defendants and the trial court entered judgment for the defendants thereon. The plaintiffs moved for judgment notwithstanding the verdict (NOV), which the trial court denied.

On appeal, the Oklahoma Court of Civil Appeals said the decisive issue was whether the defendants' sales of gas to unaffiliated, non-agent midstream companies at or near the wells were sales in a market. Citing *Mittelstaedt v. Santa Fe Minerals, Inc.*, 1998 OK 7, 954 P.2d 1203, the court stated that "the lessee has a duty to make the gas available to market at the wellhead" and also "has [a] duty to get the gas to the market in marketable form." *Slatten*, slip op. at 8. The lessee is also required to bear the cost in putting the gas in marketable form. *Id.* The plaintiffs maintained that there was no market at the wellhead because of the few purchasers there. Because the gas was raw gas, not in marketable form, the purchase contracts were simply gas processing service contracts. *Id.* The court said that "title to the gas passed at the point of sale; and the percentage of proceeds retained by the midstream companies when they sold the gas included their processing costs and fees." *Id.* The court continued that the jury necessarily agreed with the defendants that "the sales of raw gas to midstream companies constituted a marketplace sale," and that if the evidence supports that verdict, judgment on that verdict would not be disturbed. *Id.* at 9.

The court of appeals noted that the trial court had instructed the jury on what constituted a market and concluded that the defendants' evidence would make the fact of the existence of a market at the wellhead more probable than not. *Id.* There was testimony that a market exists where someone is willing to buy the gas, that there were multiple bidders for the gas at or near the wellheads, and that the initial market for the gas was at the well and the fact that end users want a processed product does not mean that the primary wellhead market does not exist. *Id.* at 9–10. There was also testimony that the defendants' sales contracts were ordinary and customary in the industry. *Id.* at 10.

After stating that the gas must also be in marketable form, the court noted testimony that title to the gas passed at the point of sale, the defendants' contracts with the midstream purchasers set quality standards specified by buyers and the gas met those specifications, and the contracts further required that the gas be marketable. *Id.* There was testimony that the gas purchase contracts were not service contracts, the gas was marketable where bought, and the sales took place in a competitive market. *Id.* Further, there was testimony that those contracts were similar to other contracts in the industry and that the defendants' gas sales at or near the wellhead were sales of a marketable product in a competitive market. *Id.*

The defendants' employee who negotiated the gas contracts testified the goal was to achieve the highest price possible and that the pricing formula is based upon a percentage of proceeds received by the midstream purchasers. *Id.* Further, because these were percentage of proceeds contracts and title passed at the point of sale, these midstream purchasers were required to pay for the gas delivered at the wellhead, even if the midstream purchaser did not sell the processed products. *Id.* There was additional testimony that the purchasers were required to pay for all volumes through the wellhead meter and that the purchasers paid for gas they used as fuel for processing and royalties were paid on that gas. *Id.* at 11.

In sum, the court found that the defendants' evidence met the standard of competent evidence on the issue of existence of a market for gas in marketable form at the wellhead. *Id.*

The plaintiffs maintained that under *Mittelstaedt*, the defendants had the burden of proof to justify a reduction in royalties resulting from processing and the value of fuel used. *Id.* The plaintiffs asserted there was no market at the wellhead, the gas was not in marketable form at the wellhead, and the midstream company contracts were service contracts to process the gas for the ultimate market at the tailgate of the processing plant. *Id.* However, the court found that the defendants' evidence contradicted each of these points, including a denial that any deductions were made. *Id.* The jury accepted the defendants' evidence and that evidence must be taken as true for the purposes of the plaintiffs' motion for judgment NOV. *Id.* The court noted that the defendants did not attempt any justification for any reductions in royalty because the market for the gas was at the wellhead and the royalty was paid based upon the full price received at the wellhead and without deductions. *Id.* at 12. Thus, the court denied the plaintiffs' claim that the trial court failed to properly instruct the jury. *Id.*

The court reviewed and rejected further grounds for error claimed by the plaintiffs. However, upon considering the standard of review of judgments entered on jury verdicts and on orders denying motions for judgment NOV, the court affirmed the judgment on the jury verdict and the order denying the motion for judgment NOV. *Id.* at 15.

The plaintiffs have petitioned the Oklahoma Supreme Court for certiorari, which is pending at the time of the submission of this report. Further, two mineral owner associations have been permitted to file as amici curiae.

PENNSYLVANIA – MINING

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

PADEP's RGGI Rule Continues Through the Regulatory Process

Continuing from previous publications of this *Newsletter*, this report provides 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. *See* 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*.

After the public comment period closed in January 2021, the Independent Regulatory Review Commission (IRRC) issued its comments on the proposed rule 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's comments, based on criteria in section 5b of Pennsylvania's Regulatory Review Act, 71 Pa. Stat. § 745.5b, addressed the significant objections to the proposed rule from the members of the regulated community and general assembly. The comments recommended that EQB explain the choice to institute the program through regulation rather than legislation, provide analysis of its statutory authority to enact the proposal, and consider recommendations from commentators on public health, safety, and welfare, economic or fiscal impact, and adequacy of data. The IRRC also asked EQB to consider delaying the 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. Under the Regulatory Review Act process, EQB will respond to these comments, and other public comments, when finalizing this rulemaking.

On March 10, 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). The RGGI Equity Principles are (1) inclusively gathering and considering input from the public related to decisions made under RGGI; (2) protecting public health and welfare, mitigating any adverse impacts on human health, especially in environmental justice communities, and seeking to ensure environmental and structural racism are not replicated in the engagement process; and (3) working equitably and with intentional consideration to distribute environmental and economic benefits of the proceeds of allowance auctions. PADEP has also joined with the Delta Institute to engage with impacted communities to identify a path for an equitable transition for all Pennsylvania residents. The Delta Institute will develop a plan to invest RGGI auction proceeds to diversify Pennsylvania's economy and assist communities that are affected by changes in the energy sector.

At the April 8, 2021, Air Quality Technical Advisory Committee meeting, PADEP presented updates on the status of and revised language for the proposed implementation of the RGGI program. PADEP summarized the key proposed changes and public comments received and updated power sector modeling. Proposed changes to the regulation include adjustment of the waste coal set-aside, expansion of the co-generation set-aside, clarification of the strategic use set-aside, the addition of annual air quality impact assessment, and the incorporation of the RGGI Equity Principles into the preamble. PADEP made a similar presentation to the Citizens Advisory Council (CAC) on April 20, 2021. PADEP presented the updated modeling and the CAC voted on the proposal at its May 19, 2021, meeting.

PADEP's proposal continues to meet opposition from the regulated industry and the general assembly. 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 multi-state program, such as RGGI, that would impose such a tax. The bill had its first consideration in the Senate on April 27, 2021, and second consideration on May 12, 2021. This bill is similar to Senate Bill 950 from the legislature's previous session, a version of which was passed as House Bill 2025 and was vetoed by Governor Tom Wolf in September 2020. *See* Vol. XXXVII, No. 4 (2020) of this *Newsletter*.

In addition to introducing legislation, Senate Republicans sent Governor Wolf a letter on April 21 advising him that they will reject all future nominees to the Public Utility Commission (PUC) due to the Governor's recent actions related to joining RGGI. *See* Letter from Senate Republicans to Governor Wolf (Apr. 21, 2021). The group has committed not to confirm any PUC nominees until Governor Wolf either removes Pennsylvania from RGGI or submits the compact to the general assembly for approval.

PADEP is currently working on the comment response document. PADEP expects to present the final regulation to EQB in summer 2021. If EQB adopts the final regulation, the regulation will be presented to the Pennsylvania House and Senate Environmental Resources & Energy Committees and the IRRC for action. If approved by the three committees, the regulation will be submitted to the Attorney General's Office, and upon approval, published in the *Pennsylvania Bulletin*.

IRRC Approves Final Rulemaking on Water Supply Replacement for Coal Surface Mining

As reported in Vol. XXXVI, No. 4 (2019) of this *Newsletter*, on November 2, 2019, the Pennsylvania Environmental Quality Board (EQB) published a proposed rule revising the water supply replacement regulations under 25 Pa. Code chs. 87–90. *See* 49 Pa. Bull. 6524 (proposed Nov. 2, 2019). The final-form regulation was submitted to the Independent Regulatory Review Commission (IRRC) on February 25, 2021. On April 15, 2021, the IRRC issued an order approving the regulation. *See* IRRC Approval Order (Apr. 15, 2021); *see also* 51 Pa. Bull. 2468 (May 1, 2021). The Senate and House Environmental Resources & Energy Committees also approved the final regulation on April 14, 2021.

Among other changes, the final rule reserves current 25 Pa. Code §§ 87.119 (surface coal mining) and 88.107 (anthracite mining) and replaces those provisions with the extensively revised new sections 87.119a and 88.107a. The most notable changes in these new sections include:

- *Water Supply Survey*. Pre-mining water supply surveys are often used to establish baseline water supply conditions. The current regulations only generally refer to such surveys. In contrast, sections 87.119a(a) and 88.107a(a) of the final rule specify that the survey must include the location and type of the water supply, the existing and reasonably foreseeable uses of the supply, the chemical and physical characteristics of the water, historical and recent water quantity measurements, and sufficient sampling to document seasonal variations in hydrologic conditions.
- *Water Supply Replacement Obligations*. Sections 87.119a(b) and 88.107a(b) clarify that if a water supply has been affected to a demonstrable extent by mining, the operator must restore or replace the water supply with a permanent source adequate for the purposes served and "reasonably foreseeable uses" of the water supply. Subsection (c) requires operators to provide a temporary water supply within 24 hours if the water supply owner/user is without a readily available alternative source of water. Under subsection (d), the Pennsylvania Department of Environmental Protection (PADEP) may provide a temporary water supply and seek to recover costs from the operator.
- *Adequacy of Restored or Replaced Water Supply*. Sections 87.119a(f) and 88.107a(f) require a restored or replaced water supply to be as reliable and permanent as the previous supply, not require excessive operation and maintenance (O&M) or result in increased cost to the user without compensation, and provide the water supply owner/user with as much control and accessibility as the previous water supply. The final rule expands the concept of "adequate quality," requiring the restored or replaced water supply to be comparable to the previous supply as documented in the water supply survey, or meet the requirements of the Pennsylvania Safe Drinking Water Act (SDWA). PADEP may require the restored or replaced water supply to be of equivalent quality to the pre-mining supply, even if this requires water of better quality than SDWA standards, if the water supply user demonstrates that such quality is necessary to meet the use served by the original supply. Finally, "adequate quantity" means the restored or replaced water supply must deliver the amount of water necessary to satisfy the purposes served by the supply as documented in the pre-mining survey, including any "reasonably foreseeable uses," which includes "the reasonable expansion of use where the quantity of the water supply available prior to mining was adequate to supply the foreseeable uses."
- *Reimbursement*. Sections 87.119a(e) and 88.107a(e) of the final rule are new provisions that require operators to reimburse water supply owners/users who replace the water supply themselves when it is later determined that the operator is responsible for the water supply problem. The operator may dispute costs that appear to be excessive based on the pre-mining survey.
- *Operation and Maintenance*. New sections 87.119a(g) and 88.107a(g) contain detailed procedures for determining O&M costs and requiring the operator to post a bond to assure payment of increased O&M costs so that the restored or replaced water supply does not result in increased costs to the user.
- *Presumption of Liability*. New sections 87.119a(j) and 88.107a(j) clarify the statutory presumption contained at 52 Pa. Stat. § 1396.4b(f)(2) that an operator is responsible for pollution or diminution of water supplies within 1,000 feet of the boundaries of areas affected by surface mining operations, and the defenses available to operators to rebut the presumption.

The final rulemaking package is available at http://www.irrc.state.pa.us/docs/3245/AGENCY/3245FF.pdf. The revised regulations will go into effect upon publication in the *Pennsylvania Bulletin*.

OSMRE Publishes 2020 Pennsylvania Evaluation Report

In March 2021, the Pittsburgh Field Office of the federal Office of Surface Mining Reclamation and Enforcement (OSMRE) released its annual evaluation report of the regulatory and abandoned mine reclamation programs administered by the Pennsylvania Department of Environmental Protection (PADEP). The report covers the 2020 evaluation year, which ran from July 1, 2019, to June 30, 2020. The report is issued pursuant to OSMRE's authority under the federal Surface Mining Control and Reclamation Act (SMCRA) to oversee the implementation of state programs that have been approved as meeting the minimum requirements of SMCRA.

The first half of the report addresses PADEP's administration of SMCRA's regulatory program. The report notes that PADEP reported over 1,100 inspectable sites, including 700 active sites, and performed over 11,000 full or partial inspections. OSMRE conducted 84 oversight inspections, including 71 in the bituminous region and 13 in the anthracite region. Of the 71 inspections in the bituminous region, 40 did not identify any violations. Of the 31 inspections where violations were identified, OSMRE identified a total of 58 violations, 53% of which related to hydrologic balance. OSMRE, "2020 Pennsylvania Annual Evaluation Report," at 10–12 (Mar. 2021).

The report similarly includes an evaluation of off-site impacts from mining. The report notes that PADEP identified a total of 48 off-site impacts related to 34 permits during the evaluation year, with 96% of permits causing no off-site impacts. Forty-four of the 48 off-site impacts related to hydrology. Those off-site impacts are classified as major (9), moderate (12), or minor (23). OSMRE noted that of the 141 total violations identified during oversight inspections, 18 involved off-site impacts, and 13 of those related to hydrology. *Id.* at 21–23.

The second half of the report addresses PADEP's administration of SMCRA's abandoned mine land (AML) reclamation program and highlights various PADEP AML projects, accomplishments, and initiatives. The report concluded that PADEP effectively administers both the regulatory and AML programs. *Id.* at 32, 50. The 94-page report is available at https://www.odocs.osmre.gov/ (to access the report, select "Pennsylvania" and "2020" in the respective state and year fields and "Annual Evaluation Reports" in the category field).

Pennsylvania to Become a Leader in Solar Energy Production

On March 22, 2021, Governor Tom Wolf announced a clean energy initiative that would produce nearly 50% of state government's electricity through seven new solar energy arrays totaling 191 megawatts to be built around the state. *See* Press Release, Gov. Tom Wolf, "Gov. Wolf Announces Largest Government Solar Energy Commitment in the U.S." (Mar. 21, 2021). Pennsylvania PULSE (Project to Utilize Light and Solar Energy), a part of the initiative, will go into operation on January 1, 2023.

Solar arrays will be built in seven locations in six counties: Columbia, Juniata, Montour, Northumberland, Snyder, and York. The Pennsylvania Department of General Services contracted with Constellation, a Pennsylvania Public Utility Commission-licensed electric generation supplier, to secure a 15-year fixed-price supply agreement. The project is expected to deliver 361,000 megawatt-hours of electricity per year, or about half the electricity used by state government annually.

To date, this is the largest government-backed commitment to solar energy announced in the United States.

PADEP Publishes Final Revised Policy on Civil Penalty Assessments for Coal Mining Operations

On February 27, 2021, the Pennsylvania Department of Environmental Protection (PADEP) published the final revision to Technical Guidance Document (TGD) No. 562-4180-306, titled "Civil Penalty Assessments for Coal Mining Operations." 51 Pa. Bull. 1083 (Feb. 27, 2021). The TGD makes several major changes to the procedures for calculating civil penalty amounts for coal mining violations, the most significant of which is the addition of new procedures for calculating water quality violations under section 605 of the Clean Streams Law, 35 Pa. Stat. § 691.605. No revisions were made to the version of the TGD that was published for public comment on October 3, 2020, which is discussed in detail in Vol. XXXVII, No. 4 (2020) of this *Newsletter*.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart, Sean M. McGovern & Casey J. Snyder
– Reporters –

Commonwealth Court Confirms EHB Discretion in Awarding Fees Under the Clean Streams Law

On February 16, 2021, the Pennsylvania Commonwealth Court affirmed the Pennsylvania Environmental Hearing Board's (EHB) decision to deny environmental groups' petition for attorney's fees after a settlement with the Pennsylvania Department of Environmental Protection (PADEP) in a third-party permit appeal over Sunoco Pipeline L.P.'s (Sunoco) Mariner East 2 pipeline because neither side acted in "bad faith." *Clean Air Council v. PADEP*, 245 A.3d 1207 (Pa. Commw. Ct. 2021). After the plaintiffs settled the dispute at the EHB over permits issued to Sunoco for its Mariner East 2 pipeline, the plaintiffs filed an application with the EHB to recover costs and fees of the litigation totaling nearly $230,000 from Sunoco, which was not a party to the settlement. *Id.* at 1210. The EHB applied a stricter standard for recovering fees from a private party than in applications to recover fees from PADEP, requiring the plaintiffs to show the private party acted in "bad faith." *Id.* at 1211. Under this standard, the EHB reasoned, permittees would not be "dissuaded from vigorously protecting their interests . . . in good faith." *Id.* (quoting *Clean Air Council v. PADEP*, 2019 EHB 228, 236). Finding no bad faith, the EHB denied the plaintiffs' application for costs and fees. *Id.*

The plaintiffs appealed the decision to the commonwealth court, arguing that the EHB should have applied the less stringent "catalyst test," which would have required the plaintiffs to meet an easier standard: that the opposing party provided some benefit the fee-requesting party sought, the suit stated a genuine claim, and their appeal was a substantial or significant reason why the opposing party provided the benefit the fee-requesting party sought in the underlying suit. *Id.* at 1215. The court rejected the plaintiffs' arguments and held "it was entirely within EHB's discretion, and *eminently appropriate*, to apply the instant bad faith standard in deciding whether or not to impose costs and fees upon a private party permittee." *Id.* at 1218 (emphasis added). Thus, the catalyst test is not the "sole and exclusive" standard the EHB may employ in cost and fee applications against a permittee under section 307(b) of the Clean Streams Law. *Id.* The court also determined PADEP had no standing to challenge the EHB's decision on a costs and fees application against a third party where PADEP's interest was entirely prospective and concerned how the EHB's application of the bad-faith standard would be applied in future costs and fees applications.

In a separate decision, the commonwealth court upheld an EHB ruling that reduced the fees awarded to a family that challenged PADEP permits for the Mariner East 2 pipeline crossing their land. *PADEP v. Gerhart*, No. 107 C.D. 2020, 2021 WL 563313 (Table) (Pa. Commw. Ct. Feb. 16, 2021). The EHB in

2019 held that PADEP misclassified a wetland on the Gerhart's property and that Sunoco had to conduct additional restoration of the wetland after completing the pipeline's construction under Sunoco's approved restoration plan. *Id.* at *1. The EHB held Sunoco to the bad-faith standard and PADEP to the catalyst test in parceling out who was responsible for the reduced legal fee award to the plaintiff. Following the same logic as its ruling in the *Clean Air Council* case, the court affirmed that the EHB had the discretion to apply both standards in awarding fees, charging no fees to Sunoco and $13,135.77 in fees to PADEP. *Id.* at *2–3.

On March 18, 2021, the plaintiffs filed an appeal with the Pennsylvania Supreme Court from the February 16, 2021, commonwealth court decision affirming the EHB's denial of their request for attorney's fees. *See* Petition for Allowance of Appeal, *Clean Air Council v. PADEP*, No. 131 MAL 2021 (Pa. Mar. 18, 2021). PADEP has also appealed the ruling that it did not have standing. *See Clean Air Council v. PADEP*, No. 132 MAL 2021 (Pa. filed Mar. 18, 2021). A date for oral argument had not been scheduled as of May 1, 2021.

Environmental Groups, PADEP Reach Settlement over Reissued General Permit

In a February 4, 2021, letter, five environmental groups asked the Pennsylvania Department of Environmental Protection (PADEP) to suspend or revoke dozens of permit approvals under recently reissued General Permit WMGR123 (General Permit). *See* Letter Re: DEP's Recent Approval of 49 Authorizations Under the New General Permit WMGR123 Without Proper Public Notice (Feb. 4, 2021). The General Permit, created in 2010, provides for the "processing, transfer and beneficial use of oil and gas liquid waste to develop or hydraulically fracture an oil or gas well." General Permit WMGR123 (as amended Mar. 14, 2012). The General Permit expired on October 4, 2020, but was extended to January 4, 2021, pending PADEP's planned renewal. PADEP began the process of updating and renewing the General Permit in 2020, and published notification on December 19, 2020, that a new WMGR123 was approved and would become effective January 4, 2021. *See* 50 Pa. Bull. 7249 (Dec. 19, 2020).

The groups alleged that PADEP failed to follow public notification requirements required under both the reissued General Permit and Pennsylvania regulations at 25 Pa. Code § 287.642(c) for 49 General Permit renewal applications for existing permits. Specifically, the groups alleged PADEP granted 49 total General Permit renewals on December 23, 2020, and January 4, 2021, without providing any public notice, or with providing public notice but under the previous version of the General Permit, despite the new General Permit becoming effective on January 4, 2021. Before any appeals were filed, PADEP and the environmental groups entered into a stipulation of settlement under which PADEP agreed to hold an additional 60-day public comment period and the environmental groups agreed not appeal any of the General Permit approvals based on public notice procedures. *See* Stipulation of Settlement (Feb. 16, 2021). PADEP published notice of the 60-day public comment period on March 20, 2021, which closed on May 19, 2021. *See* 51 Pa. Bull. 1535 (Mar. 20, 2021). The groups subsequently filed appeals of six General Permit authorizations with the Pennsylvania Environmental Hearing Board.

Editor's Note: The reporters' law firm is representing two companies whose authorizations have been appealed.

Pennsylvania Democrats Granted Intervention in Lawsuit Challenging Delaware River Watershed Drilling Ban

On February 25, 2021, by a 4-0-1 vote, the Delaware River Basin Commission (DRBC) amended its regulations to ban the drilling of unconventional wells in the Delaware River Basin. *See* News Release, DRBC, "New DRBC Regulation Prohibits High Volume Hydraulic Fracturing in the Delaware River Basin" (Feb. 25, 2021). During the special meeting, the United States abstained from the vote, but indicated support for the result, while the vote was unanimous from the state commissioners.

Prior to the amendment to the Basin regulations, Senator Gene Yaw (R-23), Senator Lisa Baker (R-20), and the Pennsylvania Senate Republican Caucus filed a lawsuit to overturn the de facto moratorium that had been in place since 2010. *See Yaw v. DRBC*, No. 2:21-cv-00119 (E.D. Pa. filed Jan. 11, 2021). The DRBC alleged it maintained its authority to prohibit construction or operation of natural gas wells within the Basin as a valid exercise of its power to regulate "projects" utilizing "water resources." Delaware River Basin Compact § 3.8 (1961). The lawsuit asserts several counts, including constitutional claims relating to eminent domain, regulatory takings, and the Republican Form of Government Clause (Guarantee Clause), and an ultra vires claim regarding the DRBC's authority over the moratorium.

On March 12, 2021, Senator Steve Santarsiero (D-10) was joined by Democratic colleagues, including the Democratic Caucus of the Pennsylvania House of Representatives, to intervene as defendants in the lawsuit. In one-page orders from U.S. District Court for the Eastern District of Pennsylvania, the court allowed the Democratic intervenors to be added as defendants in the case on March 19, 2021, and in a second order, relieved them of any obligation to respond to the initial complaint on March 24, 2021. The intervenors and the DRBC filed motions to dismiss for lack of jurisdiction and failure to state a claim on April 15, 2021, after the plaintiffs amended their complaint on March 31, 2021, to reflect the DRBC's new regulations prohibiting unconventional wells. *See* Motion to Dismiss and Memorandum of Law in Support of County Intervenors' Motion to Dismiss Amended Complaint, *Yaw v. DRBC*, No. 2:21-cv-00119 (E.D. Pa. Apr. 15, 2021). The motion to dismiss filed by the Democratic intervenors sets forth three main arguments for dismissing the lawsuit. First, the plaintiffs lack standing to file their lawsuit. Second, the plaintiffs' allegation of a regulatory taking fails as a matter of law. Third, the plaintiffs' complaint fails to plead a claim under the Guarantee Clause. The court had not ruled on the defendants' motions as of May 1, 2021.

Chesapeake Reaches $1.9 Million Settlement Agreement with PADEP, EPA over Alleged Wetland and Stream Violations

On March 24, 2021, the Pennsylvania Department of Environmental Protection (PADEP), U.S. Environmental Protection Agency (EPA), and U.S. Department of Justice executed a consent decree with Chesapeake Appalachia, LLC (Chesapeake) to resolve Chesapeake's alleged violations of the federal Clean Water Act and the Pennsylvania Clean Streams Law and Dam Safety and Encroachments Act associated with the alleged failure to identify and protect wetlands at 76 oil and gas well sites in Pennsylvania. *See* Proposed Consent Decree, *United States v. Chesapeake Appalachia, LLC*, No. 4:21-cv-00538 (M.D. Pa. Mar. 24, 2021). The alleged violations stem from discharges of dredged and/or fill material into waters of the United States and/or waters of the Commonwealth, creation of unauthorized encroachments, water obstructions, and issues related to earth disturbance activities, and stormwater management. Beginning in 2013 while renewing Pennsylvania Erosion and Sediment Control General Permit authorizations, Chesapeake discovered that some of its operations in Pennsylvania did not completely delineate all required wetlands or required resources. Chesapeake disclosed these sites to PADEP and EPA and, over the course of several years, the parties worked on how to bring Chesapeake back into compliance. Despite Chesapeake's efforts to discover and report the non-compliance, PADEP and EPA declined to address the matter under their respective policies on voluntary audit and self-disclosures. Proposed Consent Decree at 7.

Under the terms of the consent decree, Chesapeake agreed to

- pay a $1.9 million civil penalty;
- replace, restore, or enhance 25.778 acres of wetlands and 2,326 linear feet of streams;
- institute a compliance assurance program to ensure its facilities operate in compliance with federal and state law; and
- pay greater stipulated penalties than normally found in state settlement agreements, should Chesapeake fail to meet its obligations.

The consent decree was subject to a 30-day public comment period that closed on April 29, 2021, and is pending final court approval.

Environmental Justice Updates in Pennsylvania

The Pennsylvania Department of Environmental Protection's (PADEP) Office of Environmental Justice is in the process of updating its environmental justice (EJ) policy titled "Environmental Justice Public Participation Policy," in line with a recent trend of similar efforts from the Biden administration and several states to increase EJ review in regulatory actions like permitting. *See* PADEP, Environmental Justice Public Participation Policy (No. 012-0501-002) (effective Apr. 24, 2004). A revised policy could affect the process of PADEP's permitting, enforcement, and other regulatory activities.

PADEP's policy went into effect in 2004. The current policy applies to "Environmental Justice Areas," which are areas of concern (a half-mile radius from the center of the proposed permit activity and any area outside this radius impacted by the proposed activity) that are also part of a census tract with a 30% or greater minority population or 20% or greater at or below the poverty level, as defined by the U.S. Census Bureau. Permitting actions in Environmental Justice Areas are subject to increased public participation requirements. The policy applies to (1) "trigger permits," which are permits that PADEP determined to have significant public health concerns; and (2) "opt-in permits," which are all other permits that PADEP may determine warrant EJ consideration under the policy.

While a draft of the revised policy has not yet been released, PADEP signaled that it could be dramatically changing the scope of the policy. PADEP is currently in a public outreach stage of the revision process, seeking comments on how it can address EJ concerns in addition to public participation in the permitting review process. PADEP's Office of Environmental Justice held public outreach meetings in late March 2021 to discuss the timeline and seek comments on certain questions about the scope of the policy. Also, PADEP could expand the list of "trigger permits" in the revised policy to include certain oil and gas-related permits. The revisions under discussion now constitute the second proposed draft of the policy since it became effective. In a previous 2018 draft revision of the policy that was withdrawn in November 2020, PADEP proposed to include permits to drill and operate underground injection control wells for disposal of oil and gas liquid waste or enhanced recovery. *See* PADEP, Draft Environmental Justice Public Participation Policy (No. 012-0501-002) (withdrawn draft from 2018).

A draft of the revised policy is expected to be published sometime in fall 2021. *See* Office of Envtl. Justice, PADEP, "Environmental Justice Policy Revision," https://www.dep.pa.gov/PublicParticipation/OfficeofEnvironmentalJustice/Pages/Policy-Revision.aspx. A final revised policy could be in effect by spring or summer 2022, after several stages of planned public comment, internal review, and community engagement.

TEXAS – OIL & GAS

William B. Burford
– Reporter –

"Market Value at the Well" Royalty Clause Does Not Trump "Gross Proceeds" Clause

In *BlueStone Natural Resources II, LLC v. Randle*, 620 S.W.3d 380 (Tex. 2021), *aff'g in part, rev'g in part* 601 S.W.3d 848 (Tex. App.—Fort Worth 2019), the court considered the royalty provisions of 12 oil and gas leases from 2003 under which BlueStone Natural Resources II, LLC (BlueStone) was the lessee. Each of the leases consisted of a printed form that included a Paragraph 3, calling for gas royalty to be based on "market value at the well" of gas sold or used off the premises, followed by an addendum, prefaced by wording that its language superseded any contrary provisions in the printed lease, whose Paragraph 26 specified that royalties would be computed and paid on the "gross value received," with no deductions for various categories of postproduction costs.

Upholding the trial court's summary judgment for the lessors, affirmed by the court of appeals, *see* Vol. XXXVI, No. 2 (2019) of this *Newsletter*, the court held that BlueStone was required to calculate gas royalty without deducting postproduction costs. In doing so it rejected BlueStone's argument that the "gross value received" wording in the addendum did not conflict with the printed "at the well" language because it did not specify the point at which that "gross value" was to be determined. The court distinguished *Burlington Resources Oil & Gas Co. v. Texas Crude Energy, LLC*, 573 S.W.3d 198 (Tex. 2019), *see* Vol. XXXVI, No. 2 (2019) of this *Newsletter*, which had held that a royalty based on the "amount realized," ordinarily negating the deduction of costs incurred up to the point of sale, nevertheless must bear a proportionate share of postproduction costs where the royalty is to be delivered "into the pipeline," the functional equivalent of "at the well." *BlueStone*, 620 S.W.3d at 390. The difference, in the court's view, was that Paragraph 26 of the addendum to the leases at issue here called for payment of royalty based on "gross" value, whereas the instruments construed in *Burlington* did not specify whether the "amount realized" was to be gross or net. *Id.* at 391–92. As the court held in *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133 (Tex. 1996), the terms "gross proceeds" and "at the well" are inherently in conflict, and the parties had agreed to resolve that conflict by way of the addendum's introductory provision that provisions of the addendum must prevail. *Burlington* had reconciled otherwise unmodified "amount realized" language with contract terms requiring royalties to be delivered "into the pipelines," so that there was no conflict, and must not be read, as BlueStone contended, as "treat[ing] 'at the well' language as a 'trump' card that supersedes 'amount realized' language without regard to other lease terms." *BlueStone*, 620 S.W.3d at 392.

The parties also disputed whether royalty was payable on gas used as plant fuel and compressor fuel, after being commingled with gas produced from other leases. The leases' free-use clause, BlueStone argued, granting the lessee the use of gas, free from royalty, "in all operations which Lessee may conduct hereunder," allowed such use if the gas was used for the benefit of the lease, whether on or off the leased premises. *Id.* at 394. Rejecting case support for that argument from North Dakota and New Mexico and relying on the analysis of the court in *Anderson Living Trust v. Energen Resources Corp.*, 886 F.3d 826 (10th Cir. 2018), applying Colorado law, the court agreed with the lessors that the free-use clause was intended to apply only to gas used on the same lease where produced. *BlueStone*, 620 S.W.3d at 398–99. It is unlikely, the court observed, that the parties "intended a construction of the free-use clause that would inject uncertainty and lead to a fact-finding mission to determine whether . . . uses 'benefit' or 'further' the lease operations," and the absence of any limiting principle to BlueStone's favored construction, it believed, "further commend[ed] construing the free-use clause as restricted to on-lease uses." *Id.* The court remanded the question of damages to the trial court to resolve fact questions concerning the amount of compressor fuel that was free of royalty, holding that the trial court's award of damages based on the value of each lease's entire production was improper because at least some of the gas was used as compressor fuel on at least some of the leases. *Id.* at 399–400.

Lease's Broad Definition of "Drilling Operations" Held to Enable Reworking to Avoid Partial Termination Under Continuous Development Clause

The court in *Sundown Energy LP v. HJSA No. 3, Limited Partnership*, No. 19-1054, 64 Tex. Sup. Ct. J. 651, 2021 WL 1323406 (Tex. Apr. 9, 2021) (per curiam) (petition for reh'g filed May 11, 2021), *rev'g* 587 S.W.3d 864 (Tex. App.—El Paso 2019), *see* Vol. XXXVI, No. 4 (2019) of this *Newsletter*, considered an oil and gas lease covering a large amount of land in Ward County, Texas, under which HJSA No. 3, Limited Partnership (HJSA) was the lessor and Sundown Energy LP (Sundown) the lessee. The lease, whose primary term had expired in 2006, included provisions under which it would terminate after the primary term as to non-producing acreage unless continuous drilling was in progress. Paragraph 7(b) of the lease provided as follows:

> The obligation . . . to reassign tracts not held by production shall be delayed for so long as Lessee is engaged in a continuous drilling program on [specified portions of the land]. The first such continuous development well shall be spudded-in on or before the sixth anniversary of the Effective Date, with no more than 120 days to elapse between completion or abandonment of operations on one well and commencement of drilling operations on the next ensuing well.

Sundown, 2021 WL 1323406, at *1 (emphasis omitted). Paragraph 18 of the lease defined "drilling operations":

> Whenever used in this lease the term "drilling operations" shall mean (1) actual operations for drilling, testing, completing and equipping a well (spud in with equipment capable of drilling to Lessee's object depth); (2) reworking operations, including fracturing and acidizing; and (3) reconditioning, deepening, plugging back, cleaning out, repairing or testing of a well.

Id. at *2 (emphasis omitted).

Sundown spudded three development wells before the lease's sixth anniversary date and drilled a total of 14 development wells between 2006 and 2015. There were times, though, beginning in 2007, when more than 120 days had elapsed after completion of a well without the spudding of a new well. HJSA filed suit for a declaration that the lease had therefore terminated; Sundown countered that it had at all times been timely engaged in activities such as reworking and fracturing that the lease defined as "drilling operations" so that no termination had occurred. Reversing the court of appeals, the court held that Sundown's operations other than the spudding of a new well were sufficient to satisfy the continuous drilling clause.

The lessor and lessee had agreed, the court pointed out, that the Paragraph 18 definition of "drilling operations" would apply "whenever" that phrase was used in the lease. *Id.* at *3. It disagreed with HJSA that a different meaning must be inferred from Paragraph 7(b), read in isolation, in particular its reference to a well's being spudded-in, and that the more "specific" inferred meaning must take precedence over the Paragraph 18 definition. *Id.* The court could not, it said, "simply substitute 'spudded-in' for 'drilling operations' when the parties chose not to do so." *Id.* The court was unmoved by HJSA's argument that it should construe the lease "from a utilitarian standpoint" bearing in mind that the lease's objective was to encourage full exploration and development, noting Sundown's counter that Paragraph 7(b) was designed to maximize production, not just drill new wells. *Id.* at *4. "[C]ourts may not rewrite a contract under the guise of interpretation," it concluded. *Id.*

Editor's Note: The reporter's law firm was involved in this appeal on behalf of Sundown.

Texas Supreme Court Upholds Mineral Owners' Boundary Agreement and Oil and Gas Lessee's Ratification Procured by Lessee

Reversing the court of appeals, the Texas Supreme Court in *Concho Resources, Inc. v. Ellison*, No. 19-0233, 64 Tex. Sup. Ct. J. 701, 2021 WL 1432222 (Tex. Apr. 16, 2021), *rev'g Ellison v. Three Rivers Acquisition LLC*, 609 S.W.3d 549 (Tex. App.—Corpus Christi-Edinburg 2019), held that an agreement fixing the boundary between two tracts at a location apparently different from its location established in an earlier deed was valid and binding on the mineral owners and on their oil and gas lessee who ratified it.

In a 1927 deed consummating a land swap, the Sugg family conveyed to the Noelkes that part of a certain Survey or Section 1 in Irion County, Texas, "located North and West of the public road which now runs across the corner of said Survey, containing 147 acres, more or less." *Id.* at *1. As it turned out, the portion of 640-acre Section 1 north and west of the road actually contained 301 acres, not 147 acres, and the portion south and east of the road contained 339 acres rather than 493. After multiple conveyances, the minerals in the northwest portion of Section 1 became vested in the Pilon family, who in 1987 executed an oil and gas lease to Questa Oil Gas Co., which drilled a producing well, the Pilon #1, on the land. That lease was assigned in 1996 to Jamie Ellison.

In 2006 the Sugg and Farmar families (collectively, Farmars), successors to the interests of the Suggs who executed the 1927 deed, leased the southeast portion of Section 1 to Samson Resources Co. (Samson). Seeking to drill a well 100 feet south of the road, Samson obtained a drilling title opinion that questioned the location of the boundary between the two portions of Section 1, inasmuch as the 1927 deed appeared to allocate 154 more acres to the Farmars than their land would include if the road was the true boundary. Samson obtained an exception to the Texas Railroad Commission rule generally prohibiting the drilling of a well as near as 100 feet from the nearest lease boundary, after notice to and waiver by Ellison and his lessor. In 2008, desiring to conduct further drilling on land it purported to have under lease from the Farmars, Samson prepared and submitted to Carol Richey, then the mineral owner of the northwestern tract, a Boundary Stipulation of Mineral Interest between the Farmars and Richey, referencing the 1927 deed, stating that "a question has arisen among the Parties as to the physical location of the 147 acre tract" and the 493-acre tract as to the mineral estate, and declaring the boundary to be located where a survey plat prepared by Samson placed it, north of the road. *Id.* at *3.

After the boundary stipulation was executed by the mineral owners, Samson's landman sent a letter to Ellison, requesting him to

> signify your acceptance of the description of the . . . 147 acre tract as set out in the Stipulation (your leasehold), by signing both copies of this letter in the space provided below and return[ing] one copy to my attention in the enclosed self-addressed envelope. Upon your acceptance, a more formal and recordable document will be provided.

Id. The letter further noted Samson's intention to drill another well, the Sugg #3. Ellison signed and returned the letter, but the "more formal and recordable document" was never provided. *Id.* Samson then drilled three more wells, one of which was within the disputed 154 acres north of the road and another south of the road but closer than Railroad Commission rules would allow if the road were the true boundary. Samson subsequently assigned its Farmar lease, and it was eventually acquired by COG Operating LLC, an affiliate of Concho Resources, Inc. (Concho).

In 2013 Marsha Ellison, who had succeeded to the interest of her husband Jamie, filed suit against Concho and its predecessors-in-interest, alleging that she was the owner of the lease on all of Section 1 lying north and west of the road and seeking damages for the defendants' alleged trespass, including drainage of oil and gas by the well drilled too near the alleged boundary. (Although Ellison and Samson settled, Samson remained a party because Sunoco, the purchaser of oil from it and the subsequent owners of the Farmar lease and also named as a defendant, sought indemnity from Samson against any liability it might be found to have.) The trial court granted summary judgment to Concho and the other defendants on the boundary issue, but the court of appeals reversed, holding that the boundary agreement was void and incapable of being ratified because there had been no "ambiguity or error" to correct in the 1927 deed, in which the location of the boundary was clear. *See* Vol. XXXVI, No. 1 (2019) of this *Newsletter*.

The supreme court agreed with Concho that imposing a requirement that there be "objective uncertainty" concerning the "true" location of a boundary line according to an antecedent agreement such as the 1927 deed "would scuttle boundary agreements as a mechanism to avoid litigation" because parties will never know whether their informal settlement of a boundary dispute is effective until it is declared so by a court. *Concho*, 2021 WL 1432222, at *6. The Farmars and Richey could have gone to court to obtain a determination of the boundary, it observed, and perhaps a court would have concluded, as Ellison contended, that the boundary was in fact the road. *Id.* at *7. But they chose to resolve the "question" that had "arisen" about the boundary location informally by executing the stipulation, and the court saw no reason to second-guess the mineral owners' decision to bind themselves in that manner without resorting to litigation. *Id.* The mineral owners' agreement could not bind Jamie Ellison, the oil and gas lessee, the court acknowledged, but Ellison had confirmed his acceptance of the agreement by signing Samson's letter even though he was not legally required to do so. *Id.* The court saw no record evidence that Samson had fraudulently induced Jamie Ellison to sign the letter—it did not communicate that he was required to accept the boundary agreement and made no representations about its legal effect. Nor did the letter condition its binding effect on the execution of a more formal document, as Marsha Ellison contended. *Id.* at *8.

The court went on to reject Ellison's argument that under *Rogers v. Ricane Enterprises, Inc.* (*Rogers I*), 772 S.W.2d 76 (Tex. 1989), equitable defenses such as ratification are categorically unavailable in a trespass-to-try-title action such as this one. The court in *Rogers I* had said only that laches was not available as a defense where the plaintiff's right is based on legal title, the court declared. *Concho*, 2021 WL 1432222, at *9. Moreover, in a subsequent appeal in the same case, *Rogers v. Ricane Enterprises, Inc.* (*Rogers II*), 884 S.W.2d 763 (Tex. 1994), the court had rejected the jury's ratification finding because the evidence did not support it, not because the defense was unavailable. *Concho*, 2021 WL 1432222, at *9. And although abandonment of real property is not recognized in Texas, as the court had observed in *Rogers I*, Concho did not claim that Ellison had abandoned her title. Ratification is not abandonment—the relinquishment of possession with the intention of terminating ownership but without vesting it in anyone else. *Id.* The court finally rejected Ellison's reliance on the doctrine of estoppel by deed, that parties are bound by the recitals in a deed in their chain of title. The court regarded this as a modified version of the argument that objective ambiguity is required to justify a boundary agreement. Adjacent owners, the court reiterated, are free to resolve uncertainty about a boundary among themselves, and the estoppel-by-deed doctrine simply does not apply to written boundary agreements. *Id.*

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

Retained-Acreage Clauses Construed Not to Have Terminated Leases

The court in *PPC Acquisition Co. v. Delaware Basin Resources, LLC*, 619 S.W.3d 338 (Tex. App.—El Paso 2021, no pet. h.), construed the retained acreage provisions of three different oil and gas leases, the "Northern Trust" lease, the "Lowe" lease, and the "Colt" lease, each covering an interest in the oil and gas in a 640-acre section of land in Reeves County, Texas. Tom Brown acquired the leases and, at or about the end of the leases' primary terms, drilled and completed the "Colt 1" well on June 1, 2003, as a gas well in the D.A. (Devonian) Field. Brown filed a Form P-15 (Statement of Productivity of Acreage Assigned to Proration Units) with the Texas Railroad Commission on September 1, 2003, designating a 640-acre proration unit for the well. J. Cleo Thompson later acquired the leases and in December 2010 recompleted the Colt 1 well as an oil well in the Wolfbone (Trend Area) Field, filing another Form P-15 designating a 160-acre proration unit for the well. The well continued to produce, and the leases were eventually assigned to Delaware Basin Resources, LLC (DBR) and OXY USA, Inc. (OXY) and affiliates. *Id.* at 343.

The lessors of the three leases learned of the well's reclassification as an oil well in 2017. On the basis that the 2010 reclassification had caused their leases to terminate as to some of the leased premises, the Northern Trust and Lowe lessors entered into new oil and gas leases that were assigned to PPC Acquisition Company LLC (PPC). DBR, after receiving demands for releases of all but 160 acres surrounding the Colt 1 well, filed suit to quiet title to its leasehold, claiming the three leases still covered the entire 640 acres, and OXY, joined as an involuntary plaintiff, likewise petitioned the court for a declaration that the leases were in force and effect for the entire parcel. The trial court granted summary judgment to DBR and OXY, and the Northern Trust, Lowe, and Colt lessors and PPC appealed, asserting that the leases to DBR and OXY had terminated in whole or in part under their retained-acreage clauses. *Id.* at 343–44.

All of the leases contained standard habendum clauses under which they would remain in effect as long as oil or gas was produced if not terminated by some other provision. The court considered the retained-acreage clauses upon which the appellants relied in turn.

The Northern Trust lease provided that "after the primary term and after all continuous operations have ceased, Lessee and/or its heirs, successors and assigns shall release all acreage not then dedicated to a proration unit designated by the appropriate regulatory body." *Id.* at 347. Northern Trust and PPC contended that the lease had terminated in its entirety at the end of its primary term on June 1, 2003, because Brown had not by then dedicated any acreage as a proration unit until he filed his Form P-15, while DBR countered that no such filing was necessary for the Railroad Commission to have designated 640 acres as a proration unit for the well, according to the field rules for the D.A. (Devonian) Field. *Id.* at 348. The court found it unnecessary to directly decide whether or not a proration had been designated, because it disagreed that the Northern Trust retained-acreage clause created a special limitation on the lease that might cause automatic termination. A rule of construction of agreements relating to real property rights, it pointed out, is that "contractual language will not be held to automatically terminate [an oil and gas] leasehold estate unless that 'language . . . can be given no other reasonable construction . . . .'" *Id.* at 349 (quoting *Knight v. Chi. Corp.*, 188 S.W.2d 564, 566 (Tex. 1945)). The wording of the Northern Trust lease lacked a clear and unequivocal statement that it would terminate upon the lessee's failure to designate a proration unit. It only created a covenant, and not a condition, and breach of the covenant caused no automatic termination in 2003. *Id.* at 351.

The court also rejected Northern Trust's and PPC's contention that the lease, if it continued in effect at all after 2003, had partially terminated except as to 160 acres on the reclassification of the Colt 1 well in 2010. First, if the retained-acreage clause could not cause an automatic termination in 2003, it could not do so in 2010. *Id.* at 352. Further, the retained-acreage clause specified only one date on which the clause would be triggered, i.e., at the end of the primary term and after all continuous operations have ceased. *Id.* In the absence of clear and precise language indicating that the parties intended . . . to require the lessee to relinquish acreage on a continuing basis," the court said, it would not construe a retained-acreage clause to be "rolling," calling for partial termination on any but that one point in time. *Id.* The Northern Trust lease, the court held, was still in effect as to the entire section. *Id.* at 353.

The Lowe lease provided that if the lessee failed to continuously develop the leased premises, as the parties agreed Brown had not done after completing the Colt 1 well in 2003, the lease "shall terminate as to all of the leased premises" except each well then producing or capable of producing in paying quantities and 40 acres around each oil well and 160 acres around each gas well "or, in each case, such larger area as may be prescribed by the Railroad Commission of Texas (or such Governmental Agency having jurisdiction) as the proration unit for such well 'Well Production Unit' . . . ." *Id.* (emphasis omitted). The lease also provided, in its Paragraph 7(a)(iii), as follows:

> Thereafter operations on or production from . . . any Well Production Unit will perpetuate the lease only as to that Well Production Unit. This lease shall terminate as to each Well Production Unit, respectively, sixty (60) days after the date that production from and operations with respect to such Unit cease; unless, within such sixty (60) day period, Lessee re-establishes production or commences drilling or workover operations on said Well Production Unit or tenders a shut-in payment in accordance with Paragraph 5 above.

Id.

The parties agreed that, unlike the Northern Trust lease, the Lowe lease's retained acreage clause created a special limitation. They disagreed, though, on how much acreage it allowed the lessee to retain, Lowe and PPC maintaining that a gas well would hold only 160 acres because the D.A. (Devonian) Field Rules did not "prescribe" a proration unit but only established a "maximum" proration unit of 640 acres for gas wells. The court agreed with DBR that the field rules did prescribe 640-acre proration units, setting minimum distances between wells "for the purpose of permitting only one well to each six hundred forty (640) acre proration unit" and providing that "each unit containing less than six hundred forty (640) acres shall be a fractional proration unit." *Id.* at 355. But although the lease therefore did not partially terminate in 2003, it had terminated in 2010 except as to the 160 acres prescribed by the field rules for the Wolfbone (Trend Area) Field in which the Colt 1 well had been recompleted. Paragraph 7(a)(iii) clearly indicated, in the court's view, that "the parties intended for the retained-acreage clause to be triggered on more than one occasion, first, when continuous development has ceased, and thereafter, when 'production from and operations with respect to [a particular Well Production] Unit cease[.]'" *Id.* at 358 (alterations in original). When the Colt 1 well was recompleted as an oil well, the lessee was no longer maintaining either operations or production on the particular unit established according to its original gas-well classification, and the lease was no longer perpetuated as to that unit. Accordingly, the court held, the Lowe lease partially terminated as to the 480 acres outside the new 160-acre proration unit. *Id.* at 359.

The Colt lease provided that it would "ipso facto terminate" if the lessee ceased continuous development except as to portions of the leased premises it was expressly permitted to retain, consisting of 40 acres for an oil well or 160 acres for a gas well or, if "drilling or producing units have been established" by governmental order, "so much of the leased premises as is included under such order in the unit on which such well is located." *Id.* at 359–60. Colt argued that the D.A. (Devonian) Field Rules did not establish "drilling or production units" so that the lease had terminated in 2003 except as to 160 acres. Although the field rules did not establish a "drilling unit" for the field, the court observed, they did prescribe a proration unit of 640 acres for gas well production, and although Tom Brown had filed the application for a permit to drill the Colt 1 well as a "wildcat" well without specifying any particular field, the well had then been completed in the interval to which the D.A. (Devonian) Field Rules applied. *Id.* at 361–62. And because the Colt lease, like the Northern Trust lease, included no clear or express wording indicating that the parties intended for the lessee to relinquish acreage at any time other than at the end of the primary term or when continuous development ceased, it did not partially terminate when the Colt 1 well was recompleted. The Colt lease, the court concluded, had not partially terminated in either 2003 or 2010. *Id.* at 362–63.

Nonoperator's Liability for Cost of Lost Well Upheld Regardless of Operator's Alleged Negligence

The court in *Crimson Exploration Operating, Inc. v. BPX Operating Co.*, No. 14-20-00070-CV, 2021 WL 786541 (Tex. App.—Houston [14th Dist.] Mar. 2, 2021, no pet. h.) (mem. op.), affirmed the trial court's judgment, based on a jury verdict, for Crimson Exploration Operating, Inc.'s (Crimson) share of costs incurred in the drilling of the McCarn A1H well in Bee County, Texas.

BPX Operating Company (BPX) was the operator and Crimson a nonoperator under an operating agreement that appears to have been in a typical industry form, requiring the operator to conduct its activities as a reasonably prudent operator and in a good and workmanlike manner but providing that the operator "shall have no liability as Operator to the other Parties for losses sustained or liabilities incurred, except such as may result from gross negligence or willful misconduct." *Id.* at *1. The agreement required Crimson to pay 20% of the cost of operations in which it participated, including the drilling of the McCarn well. A "gas kick" or "blowout" occurred during the drilling of the well, and it had to be plugged and abandoned. When BPX billed Crimson for its share of the drilling cost, Crimson refused to pay the bill. BPX sued Crimson for the amount it owed, and Crimson asserted the defense of prior material breach by BPX. BPX, Crimson asserted, had drilled the well negligently and had breached the operating agreement by failing to meet the standard of care it imposed, thus excusing performance by Crimson. Based on the jury's findings, in response to broad-form questions, that Crimson had failed to comply with the agreement and that BPX had not, the trial court rendered judgment for BPX in the amount of Crimson's share of the well costs. *Id.* at *1–2.

On appeal Crimson complained of the trial court's refusal of jury instructions that BPX was required by the agreement to conduct its activities as a reasonably prudent operator, with further explanation of that standard. The trial court had not abused its discretion, the court of appeals held. If Crimson were excused from payment by its assertion of a material breach, liability would thereby be imposed on BPX for Crimson's share of the drilling costs, contrary to the operating agreement's exculpatory clause, the court reasoned. Crimson could not escape the exculpatory clause by filing an affirmative defense in BPX's action rather than a counterclaim asserting the breach. Therefore, the court declared, the standard of care to be applied to BPX's alleged prior material breach was that of gross negligence or willful misconduct, not the reasonably prudent operator standard that Crimson asserted. *Id.* at *5.

Reservation of Royalty Interest of 3/32, "Same Being Three-Fourths (3/4's) of the Usual One-Eighth (1/8th) Royalty," Held to Have Created "Floating" Royalty Interest

Hoffman v. Thomson, No. 04-19-00771-CV, 2021 WL 881286 (Tex. App.—San Antonio Mar. 10, 2021, no pet. h.), decided whether the reservation in a 1956 deed from Peter and Marion Hoffman to Graves Peeler reserved a royalty interest consisting of a fixed fractional royalty interest in oil and gas produced from the 1,070-acre tract conveyed or instead a "floating" royalty interest dependent upon the royalty rate provided for in oil and gas leases executed from time to time.

The deed reserved to Hoffman "an undivided three thirty-second's (3/32's) interest (same being three-fourths (3/4's) of the usual one-eighth (1/8th) royalty) in and to all of the oil, gas and other minerals, in to and under or that may be produced from the land herein conveyed." *Id.* at *3. After providing that the grantor's reserved royalty would be free of cost and nonparticipating in bonuses, rentals, or executive rights, the deed went on to provide that in the event of production, the grantor would receive "a full three thirty-second's (3/32's) portion thereof" and that he "shall own and be entitled to receive three thirty-second's (3/32's) of the gross production of all oil, gas and other minerals produced and saved" from the land. *Id.* No other contents of the deed indicated the quantum of the reserved royalty interest.

Reversing the trial court's summary judgment for the successors to the grantee's interest, which had been based on a determination that the deed had reserved a fixed 3/32 royalty interest, the court held that the deed reserved to Hoffman a floating 3/4 of the fractional royalty payable under the current lease.

The fraction of "the usual one-eighth (1/8th) royalty" language typically indicates an intent to reserve a floating interest, the court asserted, citing cases that do not actually lend much direct support to that proposition. *Id.* at *4. The rest of the court's opinion treats it as a given that a fraction of "the usual 1/8 royalty" actually means that fraction of *any* lease royalty. The court offered little explanation for that seeming departure from the words' plain meaning other than to remark that the language was "consistent with deeds of that era that had a usual 1/8 royalty." *Id.* at *5. Proceeding from its understanding that "3/4 of the usual 1/8 royalty" really means 3/4 of the lease royalty, the court "reconciled" the deed's repeated use of the 3/32 fraction by finding that the 3/32 term was used as a "placeholder or shorthand" for its full definition: three-fourths of the royalty. *Id.* at *6.

There is no indication that the court recognizes it, but this is the first case in which a Texas appellate court has held that a fraction of "the usual 1/8 royalty" or of "the 1/8 royalty" must, or even can, be read as connoting a floating royalty in the absence of other wording in the deed at issue that indicates that was the parties' intention. Other courts have indeed held that a "double" fraction that includes 1/8 of production can be construed as being consistent with a floating royalty construction, based largely on the common belief for many years that lease royalty never would deviate from 1/8, but always where other language in the same deed indicates the parties' floating-royalty intention. The plain meaning of the phrase "3/4 of the usual 1/8 royalty" seems fairly clearly to be consistent with, not contrary to, the fraction 3/32, so that there is no need to "harmonize" seemingly inconsistent deed provisions as courts have done when they have held that the expression of a fraction of 1/8 of production did not preclude a floating-royalty construction. A strong argument, perhaps, can be made that the court in this case runs afoul of the oft-repeated admonition that courts in construing deeds must not apply "mechanical rules" or look for "magic words" but instead must give words their plain meaning.

"Subject-to" Clause Held Not to Have Reserved Minerals

The court in *Ross v. Flower*, No. 03-19-00516-CV, 2021 WL 904864 (Tex. App.—Austin Mar. 10, 2021, no pet. h.) (mem. op.), construed a 1999 deed from Anthony and Gayle Ross, then the owners of both the surface and mineral estates of the land, to

Richard and Patricia Church, conveying a 20-acre tract in Fayette County, Texas. After its granting clause, conveying the land according to its description in an exhibit, the deed provided as follows:

> This conveyance however, is made and accepted subject [to] any OIL, GAS AND OTHER MINERALS, . . . and to any and all validly existing encumbrances, conditions and restrictions, relating to the hereinabove described property as now reflected by the records of the County Clerk of Fayette County, Texas.

Id. at *1 (alteration in original).

The Rosses sued the Flowers, who had acquired the land, contending that their deed had excepted all the minerals so that the mineral estate remained vested in themselves. Affirming the trial court's summary judgment for the Flowers, the court held that the deed had conveyed the minerals.

"Deeds are construed to confer upon the grantee the greatest estate that the terms of the instrument will allow," the court pointed out, and reservations by implication are not favored. *Id.* at *2. "The words 'subject to,' used in their ordinary sense, mean subordinate to, subservient to or limited by," it continued, *id.* at *3 (quoting *Kokernot v. Caldwell*, 231 S.W.2d 528, 531 (Tex. Civ. App.—Dallas 1950)), and "the principal function of a 'subject-to' clause . . . [generally] is to protect a grantor against a claim for breach of warranty when some mineral interest is already outstanding," not as a reservation, *id.* Nothing in the four corners of the deed, the court observed, "show[ed] that the parties intended the 'subject-to' clause to operate differently or to serve a purpose other than informing the grantees that other outstanding interests potentially burdened the property . . . ." *Id.* The "subject-to" clause, it concluded, did not exclude anything from the conveyance but instead merely referred to encumbrances on the land and explained and clarified the nature of the title being conveyed. *Id.* at *4.

Executor's Deed Conveying Minerals to Non-Beneficiaries of Estate Upheld

Warren L. Lockhart owned mineral interests in Section 38, Block 32, Township 3 North, T&P Ry. Co. Survey, Howard County, Texas. He died in 2001 leaving a will in which he devised the residue of his estate, including his interests in Section 38, to the trustee of a trust established in a 1992 trust agreement. The trust estate was to be held by the trustee for the life of Jean Slack Lockhart, Warren Lockhart's surviving wife, to be distributed to six named individuals upon her death. Jean Lockhart was the sole trustee after Warren Lockhart's death, and she was also appointed as independent executor of his estate, expressly with all statutory powers of a trustee under Texas law, which include the power to sell trust property. In a "Distribution Deed," dated October 22, 2002, as corrected by two subsequent correction deeds, Jean Lockhart, individually and as Executor of the Warren L. Lockhart Estate, conveyed the Section 38 mineral interests to three individuals, not the same as the ultimate beneficiaries of the trust, who subsequently conveyed their mineral interests to buyers. Jean Lockhart filed suit against the purchasers in 2018, in her capacity as trustee, seeking to establish her title as such on the basis that she had lacked authority to make a gift to the 2002 grantees and that her deed to them had been void. In *Lockhart v. Chisos Minerals, LLC*, No. 08-19-00153-CV, 2021 WL 1115921 (Tex. App.—El Paso Mar. 24, 2021, no pet. h.), the court affirmed the trial court's denial of Lockhart's motion for summary judgment and its granting that of the defendants.

After deciding, using reasoning not made altogether clear, that Lockhart could maintain a trespass to try title action, ordinarily available only where a possessory interest is involved, notwithstanding that she claimed title only to a nonpossessory royalty interest, the court turned to Lockhart's principal contention, that her deed had been void because she lacked the authority as executor to make a gift of the property belonging to the trust. Although it was undisputed that the minerals at issue had vested in Jean Lockhart as trustee at the time of Warren Lockhart's death and she had not expressly joined in the deed as trustee, the court pointed out, the estate was subject to her administration as executor, with the power of sale, and she had joined in the deed in that capacity. And although the original deed and the first correction deed had used the word "give" as part of their granting language, possibly indicating that the conveyance was an impermissible gift, the second correction deed did not and expressly recited valuable consideration, negating Lockhart's argument that the mineral conveyance was an unauthorized gift. *Id.* at *13.

The court went on to reject Lockhart's argument that she had superior title because the 2002 deed, with the correction deeds, was merely a quitclaim. In doing so it largely ignored the defendants' counter that whether or not the deeds were quitclaims was of no consequence because they would still pass whatever title the grantor had. The court instead determined the deeds were not quitclaims under the muddled Texas case law (not made less so here), notwithstanding that they only conveyed all of the grantor's interest in the minerals, rather than a specific interest, because the original deed and both corrections included special warranties. *Id.* at *15. The court also disagreed with Lockhart that the correction deeds (which had clarified that the conveyance included minerals, not just surface), having been executed only by Lockhart, were invalid for failure to satisfy the requirement of legislation enacted in 2011 that material changes to a deed are required to be joined by each party to the original instrument. Nothing in the correction deed statute makes a correction deed lacking the grantee's signature void, the court said. *Id.* at *16.

Editor's Note: The reporter's law firm has represented the mineral purchasers against Lockhart in this case.

Operator's Right of Access Not Proven

In *Cook v. Cimarex Energy Co.*, No. 07-19-00099-CV, 2021 WL 1603249 (Tex. App.—Amarillo Mar. 31, 2021, no pet. h.) (mem. op.), the court of appeals reversed a summary judgment in favor of Cimarex Energy Co. (Cimarex), the operator of the Brownlee #3H and #4H Wells in Ochiltree County, Texas, against Fletcher T. Cook, the owner of the surface of Section 49, the land on which the wells had been drilled, and adjoining land.

To gain access to Section 49, Cimarex needed to cross the adjoining Sections 48 and 129, also owned by Cook. It asserted its right to do so, when Cook filed suit in trespass long after the wells had been drilled, under two instruments styled "contract of release," one for each of the #3 and #4 wells. The respective instruments each recited that Cimarex proposed to "construct the surface location, reserve pit and road to drill" the well for a cash sum that was acknowledged to be full payment for surface damages for the well, "including the lease road and base material provided by Land Owner, reserve pit and frac pit." *Id.* at *2.

Cimarex argued that the "lease road" referred to in the release was Cook's access road through Sections 48 and 129. Even if that was so, in the court's analysis, it would not resolve the question of Cook's consent in Cimarex's favor because nothing in the text definitively showed the parties' intention to grant Cimarex a right-of-way across adjacent property. *Id.* at *4. The scope of the releases was expressly defined to acknowledge Cook's ownership and to define surface activities on Section 49 only, the court said, and no certain or definite language stated Cook's consent to use the road beyond Section 49 onto Sections 48 and 129. *Id.* A factfinder might ultimately determine from extrinsic evidence that the "lease road" included the road across Cook's adjoining land, the court observed, but the existence of genuine issues of material fact prevented that determination from being made as a matter of law. *Id.* at *5.

Cimarex also argued that Cook was barred by estoppel or quasi-estoppel from withdrawing his consent to the use of the off-lease road. Again, though, the releases did not establish that consent, and if it was verbal, a fact issue existed concerning the extent of the consent, whether permanent or temporary and over what tracts. *Id.* at *6.

Surface Owner Not Prohibited from Pouring Concrete Slab over Pipeline

The court in *Energy Transfer Fuel, L.P. v. 660 North Freeway, LLC*, No. 02-20-00170-CV, 2021 WL 1569702 (Tex. App.—Fort Worth Apr. 22, 2021, no pet. h.) (mem. op.), affirmed summary judgment for Tindall Properties, Ltd. (Tindall) and 660 North Freeway, LLC (660 North Freeway), the surface owner of a five-acre tract in Fort Worth and its affiliated tenant, against Energy Transfer Fuel, L.P. (ETF), the operator of a high-pressure gas pipeline through an easement strip along the eastern boundary of the tract.

The dispute had arisen as Tindall and 660 North Freeway prepared to build a multi-level self-storage complex on the tract, the plans for which included pouring a six-inch concrete slab over the easement strip. They had filed suit for a declaratory judgment after ETF objected. The principal issue was whether or not, as ETF contended, the 1988 right-of-way agreement under which ETF operated its pipeline prohibited the pipeline's being covered by a concrete slab.

The agreement provided, in its Terms 3 and 4, that the easement holder must restore any improvements on the land that might be removed, altered, or damaged in the exercise of the easement rights and must pay the landowner for any losses where complete restoration of improvements could not be made. Its Term 6 provided that the landowner reserved the right to use the land in any manner that would not prevent or interfere with the exercise of the easement rights, provided that the landowner "shall not construct or permit to be constructed any house, building or structure of any kind whatsoever on the easement." *Id.* at *1.

The court agreed with the landowners that the concrete slab was not a "structure" prohibited by Term 6. To apply such a broad definition of "structure" would, it said, result in all improvements being structures, ignoring the context of the agreement, particularly its treatment of "improvements" in Terms 3 and 4. *Id.* at *5. The court further held that the plain language of the easement agreement belied ETF's argument that the landowners' paving of the easement strip would interfere with its easement rights in violation of Term 6. The other terms of the easement, the court pointed out, gave ETF the right to remove all or any part of an improvement if necessary, subject to its obligation to restore the paving or to compensate the landowner. *Id.* at *6.

ETF also argued that the concrete slab would violate Tex. Health & Safety Code § 756.122(a), restricting construction affecting pipeline easements "unless there is a written agreement . . . to the contrary between the owner or operator of the affected pipeline facility and the person that places or causes a construction to be placed on the easement . . . ." Here there was such a "written agreement"—the easement agreement— that was "to the contrary" in that it would have, according to ETF's interpretation, barred the paving as a risk to its pipeline and imposed upon ETF, rather than upon the landowner as provided in the Health & Safety Code, the cost of any changes needed to protect the public or the pipeline from risks created by the construction. *ETF*, 2021 WL 1569702, at *7.

Failure of Land Description in Original Lease Held Remedied by Recorded Memorandum and Amendments

MEI Camp Springs, LLC v. Clear Fork, Inc., No. 11-19-00048-CV, 2021 WL 1584815 (Tex. App.—Eastland Apr. 23, 2021, no pet. h.), affirmed summary judgment for Clear Fork, Inc. and Gunn Oil Company (collectively, Gunn), lessees of a tract of land in Fisher County, Texas, from Howard and Judy Gordon, against MEI Camp Springs, LLC (MEI), the lessee under a top lease from the Gordons on the same land.

MEI asserted that the Gunn lease was void under the statute of frauds because it lacked a valid land description. In fact, the lease apparently referred to an Exhibit A for its property description, but there was no Exhibit A attached to it. However, the Gordons had executed a memorandum of the lease for recordation that did include an Exhibit A with a metes and bounds description of the land, with words of grant, as well as two subsequent amendments, the first of which amended the property description and the second of which recognized the original lease as being "in full force and effect," with words of grant. *Id.* at *7. These supplemental documents, said the court, had remedied the absence of a property description in the original lease. The description did not have to be physically added to the original document, as MEI maintained. *Id.*

Force Majeure Clause Held Applicable Regardless of Whether Delay in Operations Caused Lessee's Failure to Meet Drilling Deadline

The court in *MRC Permian Co. v. Point Energy Partners Permian LLC*, No. 08-19-00124-CV, 2021 WL 1661193 (Tex. App.—El Paso Apr. 28, 2021, no pet. h.), considered the appeal by MRC Permian Co. (MRC), the lessee of four oil and gas leases covering almost 4,000 acres in Loving County, Texas, of a summary judgment in favor of its lessors and their new lessee that the leases had partially terminated because of MRC's failure to commence a well within the time required by the lease. The court of appeals reversed, agreeing with MRC that the trial court had erroneously failed to consider the effect of the leases' force majeure clause, which read as follows:

> 13. Force Majeure. When Lessee's operations are delayed by an event of force majeure, being a non-economic event beyond Lessee's control, if Lessee shall furnish Lessor a reasonable written description of the problem encountered within 60 days after its commencement, and Lessee shall thereafter use its best efforts to overcome the problem, this lease shall remain in force during the continuance of such delay, and Lessee shall have 90 days after the reasonable removal of such force majeure within which to resume operations . . . .

Id. at *7.

Each lease provided for a primary term that ended on February 28, 2017. At that time they would terminate as to all land except tracts then containing a commercial well, except that the partial termination could be delayed by the lessee's conducting a continuous drilling program. The lease would be preserved as to all of the land so long as MRC began drilling a new well within 180 days after the commencement of the drilling of the last previous well. Because MRC had commenced its last well during the primary term on November 22, 2016, the lease required it to begin drilling the next one by May 21, 2017, in order to avoid the partial termination.

MRC was using a specific drilling rig, "Rig 295," in its operations in the area because of its experienced crewmen and specialized equipment. It had scheduled Rig 295 to spud a well on the land within these leases on May 11, 2017, but because of an administrative error, MRC delayed the spudding until June 2017, beyond the continuous drilling deadline. On April 21, 2017, though, Rig 295 had experienced a delay of roughly 30 hours during the drilling of a well on other land when unexpected wellbore instability occurred and needed to be addressed. On June 13, 2017, 53 days afterward, MRC notified the lessors of the four leases by letter of the April event involving Rig 295. On June 15, 2017, Point Energy Partners Permian LLC, having acquired new leases from the mineral owners, responded to MRC's letter, questioning that MRC had complied with the leases' continuous development provisions, whereupon MRC filed suit for a declaratory judgment that the force majeure clause had extended its drilling deadline until 90 days after the Rig 295 delay.

The court first rejected the lessors' assertion that the triggering event under a force majeure clause cannot originate off the leasehold. It agreed with MRC that to impose such an "on-lease" condition would add a limitation to the force majeure clause that the parties did not include in the lease. *Id.* at *8. It then turned back what may have been the lessors' most appealing argument, that the triggering event must have caused MRC to miss its deadline in order to enable it to invoke the clause and that MRC's interpretation, that its brief, off-lease delay was sufficient, would transform the clause into a postponement-at-will provision. The parties had failed to stipulate in the leases that MRC's triggering event had to be a substantial factor or the direct link in MRC's failure to meet its deadline, the court pointed out; rather, the force majeure clause simply provided the lease "shall remain in force" during any delay due to force majeure and that the lessee "shall have 90 days after the reasonable removal of such force majeure within which to resume operations." *Id.* at *9. Even if there were a causal link requirement, the court further observed, there was a genuine fact issue whether the off-lease delay or instead a scheduling error caused MRC's missed deadline, making summary judgment improper. *Id.* at *10. Likewise, according to the court, the lessor's remaining arguments against the application of the force majeure clause—that the alleged delay resulted from MRC's own economically driven choices and not force majeure and that MRC's notice of the alleged triggering event was deficient—themselves created genuine issues of material fact that precluded summary judgment. *Id.* at *11.

Editor's Note: The reporter's law firm has been involved in this appeal on behalf of the appellees.

WYOMING – OIL & GAS

Jamie L. Jost & Amy Mowry
– Reporters –

Wyoming Legislature Passes Numerous Energy-Related Bills

In addition to the bills listed below, under Enrolled Act No. 45 (HB 1), the Wyoming legislature provided for supplemental appropriations for the fiscal biennium commencing July 1, 2020, and ending June 30, 2022, containing an allocation of $10 million in matching funds related to carbon capture, utilization, and storage projects, including coal power plant retrofit applications. Distribution of the funds will be conditioned on a funds match from the applicant for any such grant. Grants will be determined on the likelihood of the proposed project to, among other things, increase the national and international exposure of the state of Wyoming and its institutions, instrumentalities, and political subdivisions as participants and locations for innovation in the use of carbon-based energy and carbon capture, utilization, and storage applications.

HB 166 (Enrolled Act No. 88): Utilities—Presumption Against Facility Retirements

This Act is effective July 1, 2021, and creates Wyo. Stat. Ann. §§ 37-2-134 and 37-3-118 addressing public utilities. Section 37-2-134 requires the Public Service Commission (PSC) to consider the effect on available reliable dispatchable electricity to Wyoming customers before authorizing or approving the retirement of an electric generation facility, and to also consider the impact any shortage of energy across the nation may have on Wyoming customers. The Act establishes a rebuttable presumption against the retirement of an electric generation facility, defined as one that uses natural gas or coal as its fuel. Any public utility seeking to retire an electric generation facility must prove that cost savings will result to customers thereby and that an insufficient supply of dispatchable energy will not result from the retirement. Under section 37-3-118, any public utility that fails to rebut the presumption under section 37-2-134 may not recover costs of retirement from rate-paying customers.

HB 189 (Enrolled Act No. 90): Mine Product Taxes for Natural Gas Consumed On-Site

Effective January 1, 2022, this Act amended the provisions of Wyo. Stat. Ann. §§ 39-14-201, -203 and -205 to clarify that natural gas consumed on-site that would otherwise have been vented and flared is exempt from taxation as long as the gas is from a qualified well, defined as (1) a well connected to a pipeline that lacks takeaway capacity; (2) a producer's well not connected to a pipeline, but within lands dedicated to a pipeline operator by the producer; or (3) a producer's well not connected to an existing pipeline nor contractually dedicated. Natural gas consumed for any other purpose is subject to severance taxes. This Act ostensibly provides an opportunity for oil producers to utilize for other productive purposes, including cryptocurrency mining, natural gas that would normally be flared into the atmosphere. This may be especially significant considering SF 38, also passed into law as Enrolled Act No. 73, which grants company status to decentralized autonomous organizations, giving more legitimacy to cryptocurrency startups.

HB 207 (Enrolled Act No. 67): Coal-Fired Generation Facility Closures—Litigation Funding

Effective as of its signing into law on April 6, 2021, this Act appropriates $1.2 million from the general fund to the office of the governor to allow the Wyoming Attorney General to commence and prosecute lawsuits against other states and other states' agencies that enact and enforce laws, regulations, or other actions that impermissibly impede Wyoming's ability to export coal or that cause the early retirement of coal-fired generation facilities located in Wyoming. This appropriation is for the period beginning with the effective date of the Act and ending June 30, 2030. The Act requires the Attorney General to report annually until 2030 to the Joint Minerals, Business and Economic Development Interim Committee on the expenditure of any of the appropriated funds, and the status of any ongoing litigation funded under the Act.

SF 29 (Enrolled Act No. 10): Revised Uniform Law on Notarial Acts

Although not strictly energy focused, changes to Wyoming's notarial statutes are important to oil and gas stakeholders executing agreements pertaining to Wyoming hydrocarbon ownership and production. This Act, effective July 1, 2021, creates Wyo. Stat. Ann. §§ 32-3-101 to -131, repeals former notarization laws, and harmonizes Wyoming's notarial statutes with those of the Uniform Electronic Transaction Act, including the addition of provisions for enforcement and cancellation of notarial commissions in appropriate circumstances, provisions for remote online notarization and remote ink notarization, provisions for education and record-keeping requirements for notaries, and increases to fees.

SF 43 (Enrolled Act No. 4): Wyoming Energy Authority Amendments

The Wyoming Energy Authority (WEA) was created effective July 1, 2020, as the successor entity to the Wyoming Pipeline Authority and the Wyoming Infrastructure Authority, meant to diversify and expand economic benefits to Wyoming through the production, development, and transmission of energy and natural resources. Effective July 1, 2021, this Act amends Wyo. Stat. Ann. §§ 37-5-501, 37-5-503, and 37-5-602 addressing the scope and purposes of the WEA. The amendments redefine "energy projects" to include geothermal and pumped hydro energy projects, and also add definitions for "critical material" (defined as "any substance used in technology or production for which there are supply risks and for which there is no readily available or accessible substitute in the United States") and "rare earth mineral" (defined as "a metallic element of the lanthanide series of the periodic table, scandium, yttrium and any other metallic element with similar physical and chemical properties to any element specified in this paragraph"). The authority is further charged with supporting efforts to maintain and expand the rare earths, critical materials, and trona industries, among other mineral industries in Wyoming.

SF 60 (Enrolled Act No. 9): Monthly Ad Valorem Tax Revisions

This Act amends Wyo. Stat. Ann. §§ 21-13-310, 39-13-111, and 39-13-113 as necessary to implement its new ad valorem tax payment requirements for mineral production. Beginning January 1, 2022, under this Act monthly payment of ad valorem taxes on mineral production will be required. As to 50% of production from the 2020 calendar year and all production from the 2021 calendar year, production will be paid at 8% per year, beginning December 1, 2023, until the total outstanding amount is repaid. Monies are appropriated under the Act for use by counties to address shortfalls caused by the transition to monthly payments. Timely payments made in accordance with the revisions shall not be subject to penalties or interest. If a taxpayer fails to make timely payments, all applicable penalties and interest shall be calculated from the date the tax would have been paid if monthly payments began January 1, 2020.

SF 118 (Enrolled Act No. 72): Federal Emergency COVID-19 Relief Funding

To the extent oil and gas operators were able to benefit from the Governor's various CARES Act relief programs in 2020, this Act may provide additional relief as it extends eligibility for qualified applicants under the prior programs until December 31, 2021. The Energy Rebound Program is covered by this extension. Any further aid will be limited by the available funding and may be subject to the Governor's creation of new programs or expansion of previous programs. Some funding is not available until September 1, 2021.

SF 136 (Enrolled Act No. 49): Public Service Commission Considerations

This Act, effective July 1, 2021, amends Wyo. Stat. Ann. § 37-2-122 to expand the considerations for the PSC to include reliability and any associated costs that may affect consumer rates when retirement of a major facility or construction of a new facility is proposed. The Act authorizes the PSC to consider reliability and cost externalities incurred by the state of Wyoming in matters relating to the construction or retirement of major facilities with the potential for an immediate effect on rates. The PSC is also authorized to consider reliability and costs externalities incurred by the state of Wyoming in proceedings to recover through rates the costs of the construction or retirement of major facilities.

SF 152 (Enrolled Act No. 70): Connection of Utility Services

This Act is effective July 1, 2021, and amends Wyo. Stat. Ann. §§ 15-1-132 and 18-2-116 to prohibit cities, towns, and counties from enacting laws and policies that would prevent the connection or reconnection of an electric, natural gas, propane, or other energy utility service by a public utility. The Act protects Wyoming utility customers from having to pay higher rates because of ordinances that might prohibit the use of a specific energy source.

CANADA – OIL & GAS

Matthew Cunningham
– Reporter –

Recent Changes to the Alberta and Saskatchewan Oil and Gas Regulatory Regimes

Several changes to the Alberta and Saskatchewan oil and gas regulatory regimes in December 2020 and April 2021 will have impacts on companies operating in the two western Canadian provinces. Following the well-publicized decision in *Orphan Well Ass'n v. Grant Thornton Ltd.*, 2019 SCC 5, and with both provinces experiencing an increasing number of distressed oil and gas assets, both provincial governments have made or are making changes to their liability management regimes as they relate to oil and gas. Building on this, the Alberta Energy Regulator (AER) has also made changes to reporting requirements for licensees in the province. These changes are designed to improve the ability of the AER and the Saskatchewan Ministry of Energy and Resources (MER) to hold oil and gas operators accountable for their liabilities.

Liability Management Frameworks

Alberta

Changes to Alberta's *Oil and Gas Conservation Rules* (OGCR), Alta. Reg. 151/1971, and *Pipeline Regulation* (PR), Alta. Reg. 91/2005, to implement the province's new liability management framework came into effect on December 3, 2020. These changes are meant to address five main policy points:

- to provide guidance and support for distressed operators;
- to better assess operator liabilities and capabilities;
- to reduce inactive site inventories;
- to address legacy and post-closure sites; and
- to expand the mandate of the Orphan Well Association (OWA).

The OWA is an independent industry-funded organization that deals with oil and gas assets that do not have solvent or responsible owners. It has been experiencing an increased inventory of orphaned assets in recent years, which has resulted in a heavier reliance on government financing.

As part of the AER's inventory reduction mandate, the new changes include a new definition of "closure" which encompasses both abandonment and reclamation. The new definition in section 3.05 of the OGCR states: "'closure' means the phase of the energy resource development life cycle that involves the permanent end of operations, and includes the abandonment and reclamation of wells, facilities, well sites and facility sites." The same definition exists in section 1(1)(d.1) of the PR as the term relates to pipeline infrastructure. This definition ties into a number of new powers granted to the AER involving closure.

Under section 3.012(g.1) of the OGCR, the AER can now establish closure timelines for licensees by issuing directives. The AER may now also establish closure quotas pursuant to section 3.014(1) of the OGCR. These quotas can impose certain requirements on the amount of work to be completed, amounts of money to be spent by the licensee, or both with respect to the closure of a licensee's wells and facilities. In addition, under section 3.015(1) of the OGCR the AER may now require a licensee to submit a closure plan. Such closure plans need to include information required by the AER and require the regulator's approval. Further, the new provision allows the AER to direct the timing and priority for performing work under closure plans.

In sum, the new provisions regarding closure give the AER significantly more power and discretion over licensees' closure plans, including deadlines and minimum expenditure. Further details of how these changes will be implemented will become available once the AER begins to issue directives on these points.

An additional change involves a nomination process whereby an eligible requestor can request that a licensee prepare a closure plan or plans for nominated wells and facilities. An "eligible requestor" is defined in section 3.016(2) of the OGCR as landowners, the Minister or public lands disposition holders, First Nations band councils, Metis settlements, or municipalities, depending on the status of the land on which the well or facility is situated.

Under the provision, where a well or facility has remained in an inactive or abandoned state for five or more years and an eligible requestor makes a request of the AER, the licensee of the applicable well or facility shall prepare a closure plan for that well or facility, which, in line with the above changes, will require information disclosure as mandated by the AER, as well as the regulator's approval. As with the above changes, further details of this process remain to be seen. Notably, however, this is not a permissive requirement but a mandatory one.

Saskatchewan

Saskatchewan is proposing to make significant changes to its oil and gas liability management through amendments to *The Oil and Gas Conservation Regulations, 2012* (SK OGCR), R.R.S. c O-2 Reg 6, as well as new regulations, to be called *The Financial Security and Site Closure Regulations* (FSSCR). The FSSCR would replace current provisions in the SK OGCR regarding end-of-life obligations for oil and gas assets in the province.

The FSSCR proposes the introduction of an Inactive Liability Reduction Program (ILRP), which would obligate licensees to retire a certain percentage of their inactive liabilities every year with the goal of reducing the aggregate number of inactive wells and facilities in Saskatchewan. The ILRP is expected to commence in January 2023, to coincide with the wind-down of the province's Accelerated Site Closure Program and to give licensees time to prepare for potentially increased site closure obligations.

Saskatchewan is also proposing to modify its liability rating regime to create the Enhanced Liability Rating Formula (ELRF). The ELRF would incorporate improved measures to calculate asset value, using true corporate netbacks instead of the current method of calculating liability ratings, which uses industry average netbacks. With the use of industry averages, many licensees' liability ratings were substantially higher or lower than the average, leading to difficulties in determining whether licensees were experiencing issues that would impact their liability rating in a timely manner. For instance, cash flow interruptions would not necessarily be highlighted under the industry average netback method, though this would impact a licensee's ability to adequately address its liabilities. The ELRF proposes to remedy this by assessing licensees' financial health based on a model incorporating annual net income, as well as licensees' ratio of asset value to liabilities.

Lastly, the MER is proposing to make changes to how and when additional security will be required for license transfers between licensees. Currently, licensees may transfer oil and gas assets including a high proportion of inactive assets to junior producers. The transferor may have the assets to account for these liabilities under Saskatchewan's liability rating system; however, the junior producer may not. Following such a transfer, the junior producer's liability rating may change and additional security may be required, something such producers are not always in a position to provide. To remedy this, the MER is proposing to use a proportional risk transfer model that would evaluate both the transferor and transferee's financial capacity prior to the transfer. If liabilities will move from a low-risk state to a high-risk state as a result of the transfer, the MER will require additional security from the parties before approving applications for such a transfer. However, further details regarding this security remain to be seen.

Reporting Requirements

In addition to the changes to the OGCR and PR noted above, Alberta has also implemented additional reporting requirements in the oil and gas sector for applicants for licenses, licensees, and approval holders in *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licenses and Approvals* (Directive 67). These requirements are designed to serve as an early warning system for the AER and will require operators to not only obtain eligibility but to maintain it as well.

Financial Reporting

Section 4.4 of Directive 67 imposes an annual obligation on applicants and licensees to provide financial summaries and audited financial statements to the AER. If audited financials are not available, the applicant or licensee must provide unaudited versions within 180 days of its fiscal year end. Further, applicants for licenses will need to provide the AER with financing details, if the applicant is a new company with no available financial history. This may have implications for new entrants to the sector who may wish or be required to keep details of their financial backing confidential.

Risk Factors

Section 4.5 of Directive 67 states that an applicant must not pose an "unreasonable risk." The section provides a substantial list of potential risk factors the AER will consider in determining whether an applicant poses an unreasonable risk, including:

- the ability of an applicant, licensee, or approval holder to provide reasonable care and measures to prevent impairment or damage in respect of oil and gas assets;
- outstanding debts owed to the AER or the OWA by the applicant, licensee, or approval holder, or by current or former licensees or approval holders directly or indirectly associated or affiliated with the applicant, licensee, or approval holder or its directors, officers, or shareholders; and
- outstanding debts in respect of municipal taxes, surface lease payments, public land disposition fees, or rental payments owed by the applicant, licensee, or approval holder, or current or former licensees or approval holders directly or indirectly associated or affiliated with the applicant, licensee, or approval holder or its directors, officers, or shareholders.

Directive 67 also empowers the AER to assess any other factor it may deem appropriate in the circumstances.

Material Changes

Section 5 of Directive 67 requires licensees and approval holders to disclose material changes to the AER within 30 days of such change. Material changes include changes to corporate or legal structure, sales of all or substantially all of a licensee's assets, and significant changes to working interest participant arrangements, including participant information and proportionate shares. This may require operators to provide substantial additional disclosure of information.

It is worth noting that Directive 67 imposes additional requirements; these are a few of the more salient ones. Failure to provide the required information will allow the AER to revoke licenses or restrict licensee eligibility, including by mandating the payment of additional security.

Conclusion

Facing challenges brought by volatile commodities pricing and broader economic trends, the AER and MER have adopted or are in the process of adopting new regulatory options to allow both to better address issues arising in the oil and gas space. Generally, these include more access to information from oil and gas operators regulated by the AER and MER and updated liability management processes. Whether these steps will have the desired effect of addressing increasing liability inventory remains to be seen, but companies operating in the oil and gas sector in Alberta and Saskatchewan would be well-advised to keep abreast of these developments.

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

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