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FEDERAL — MINING

Wells Parker
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– Reporters –

Minerals Mining Added to FAST-41 Covered Sectors

On January 8, 2021, the Federal Permitting Improvement Steering Council (FPISC) issued a final rule to include mining as a qualified sector eligible for coverage under title 41 of the Fixing America's Surface Transportation Act (FAST-41) 42 U.S.C. §§ 4370m to 4370m-12. *See* Adding Mining as a Sector of Projects Eligible for Coverage Under FAST-41, 86 Fed. Reg. 1281 (Jan. 8, 2021) (to be codified at 40 C.F.R. ch. IX). The majority of the FPISC voted in favor of adding mining as a covered sector, noting its importance to infrastructure development and the likelihood of necessary extensive and complex federal and state environmental reviews and authorizations. *Id.* at 1282. Accordingly, the FPISC determined that mining projects satisfying the other requirements of 42 U.S.C. § 4370m(6) could benefit from the enhanced efficiency, transparency, and predictability provided by FAST-41 coverage. 86 Fed. Reg. at 1282.

FAST-41 requires the designation of a lead agency to assume responsibility for the permitting effort. 42 U.S.C. § 4370m-2(a)(5). The executive director of the FPISC must also maintain an online "Permitting Dashboard" to track the status of federal environmental reviews and authorizations for eligible projects.

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FEDERAL — OIL & GAS

Kathleen C. Schroder
– Reporter –

Biden Administration Initially Suspends Oil and Gas Approvals and Indefinitely Pauses Leasing

Within a week of President Biden's inauguration, the incoming administration issued two separate orders—a secretarial order suspending authority of bureaus to issue oil and gas authorizations and an executive order pausing onshore and offshore oil and gas leasing.

First, on January 20, 2021, the Acting Secretary of the Interior, Scott de la Vega, issued Secretarial Order No. 3395, "Temporary Suspension of Delegated Authority" (Jan. 20, 2021) (Order). The Order suspends the delegated authority of bureaus within the U.S. Department of the Interior (Department), including the Bureau of Land Management (BLM), Bureau of Ocean Energy Management (BOEM), and Bureau of Safety and Environmental Enforcement (BSEE), "[t]o issue any onshore or offshore fossil fuel authorization, including but not limited to a lease, amendment to a lease, affirmative extension of a lease, contract, or other agreement, or permit to drill." *Id.* § 3(g). The suspension lasts for 60 days. *Id.* § 5.

The Order does not expressly prohibit the issuance of "fossil fuel authorization[s]" but rather directs that individuals serving as Secretary, Deputy Secretary, Solicitor, or an Assistant

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ENVIRONMENTAL ISSUES

Randy Dann & Andrea M. Bronson
– Reporters –

EPA Issues Guidance on Applying the Supreme Court's Decision in *County of Maui v. Hawaii Wildlife Fund*

On January 14, 2021, the U.S. Environmental Protection Agency (EPA) issued a guidance memorandum on applying the U.S. Supreme Court's *County of Maui v. Hawaii Wildlife Fund, 140 S. Ct. 1462 (2020),* decision under the Clean Water Act's (CWA) section 402 National Pollutant Discharge Elimination System (NPDES) permit program. *See* 86 Fed. Reg. 6321 (Jan. 21, 2021). The full guidance memorandum is available at https://www.epa.gov/sites/production/files/2021-01/documents/final_ow_maui_guidance_document_-_signed_1.14.21.pdf. The purpose of the guidance memorandum is to clarify when an NPDES permit is necessary under the CWA for point source discharges that travel through groundwater before reaching a water of the United States. *See* 86 Fed. Reg. 6321. In its decision in *Maui*, the Supreme Court held that an NPDES permit is required for a discharge of pollutants from a point source that reaches "waters of the United States" after traveling through groundwater if that discharge is the "functional equivalent of a direct discharge from the point source into navigable waters." 140 S. Ct. at 1477. The decision also outlines seven non-exclusive factors to consider when evaluating whether a discharge of a pollutant from a point source that travels through groundwater to a water of the United States is a point source. *Id.* at 1476–77. A full summary of the *Maui* decision is available in Vol. XXXVII, No. 2 (2020) of this *Newsletter*.

Because the *Maui* opinion "leaves significant uncertainty concerning how the regulated community and permitting authorities should evaluate point source discharges that travel

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Id. § 4370m-2(b)(1)(A). Within 60 days of a project being entered into the Permitting Dashboard, the lead federal agency must coordinate with other cooperating agencies to develop a concise plan to identify the roles and responsibilities to complete requisite reviews and authorizations, develop a permitting timetable, and coordinate public and tribal participation. *Id.* § 4370m-2(c)(1)(A). Participating federal agencies are required to coordinate environmental reviews and authorizations where possible. *Id.* § 4370m-4(a). FAST-41 also provides additional legal protections by reducing the statute of limitations to challenge any authorizations of a covered project from six to two years. *Id.* § 4370m-6(a)(1)(A). Additionally, all National Environmental Policy Act challenges to a covered project will be reviewed only when the challenging party submitted a related comment during the environmental review. *Id.* § 4370m-6(a)(1)(B).

Temporary Suspension of Delegated Authority to DOI Bureaus and Offices

On January 20, 2021, the Acting Secretary of the Interior issued Secretarial Order No. 3395, "Temporary Suspension of Delegated Authority" (Jan. 20, 2021), suspending the delegation of authority to all U.S. Department of the Interior (DOI) bureaus and offices for 60 days. The suspension applies to the following actions: (1) publication of proposed or final agency action in the *Federal Register*; (2) issuing or revising resource management plans; (3) granting of rights-of-way, easements, or other conveyances of property or interests; (4) approving or amending plans of operations under the General Mining Act of 1872; (5) issuing any final decisions with respect to R.S. 2477 claims; (6) approving the hiring of any personnel assigned to a position at or above the level of GS 13, with the exception of seasonal or emergency workers; and (7) issuing any onshore or offshore fossil fuel authorization, including a lease, amendment to a lease, affirmative extension of a lease, contract, or permit to drill. *Id.* § 3. While the suspension remains in effect, approval of any of the above actions must come from the Secretary, Deputy Secretary, Solicitor, or Assistant Secretary, as applicable. *Id.* § 4.

The Ute Indian Tribe of the Uintah and Ouray Reservation immediately responded, alleging violations of the United States' treaty and trust responsibilities to the Tribe, and requesting an exception for energy permits and approvals on Indian lands. *See* Letter from Luke Duncan, Chairman, Ute Indian Tribe Bus. Comm., to Scott de la Vega, Acting Sec'y of the Interior (Jan. 21, 2021). Shortly thereafter, the Senior Counselor to the Secretary, exercising delegated authority of the Solicitor, issued a follow-up memorandum clarifying that Secretarial Order No. 3395 only applies to actions on non-Indian federal lands, and is not applicable to actions with respect to Indian tribes and activities on tribal lands. *See* Memorandum from Robert T. Anderson, Senior Counselor to the Sec'y, to Darryl LaCounte, Dir., Bureau of Indian Affairs, on Non-Application of Secretarial Order 3395 to Actions Relating to Indian Lands (Jan. 25, 2021).

Revocation of Executive Order No. 13,766

On the first day of his administration, President Biden issued Executive Order No. 13,990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," 86 Fed. Reg. 7037 (Jan. 20, 2021). This executive order was intended to roll back environmental actions of the Trump administration, and included the revocation of Executive Order No. 13,766 (EO 13,766), "Expediting Environmental Reviews and

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Approvals for High Priority Infrastructure Projects," 82 Fed. Reg. 8657 (Jan. 24, 2017).

The Trump administration issued EO 13,766 in January 2017 to streamline and expedite environmental reviews and authorizations for infrastructure projects and, in particular, projects deemed a high priority for the nation. With respect to projects requiring federal review or authorizations, EO 13,766 directed the Chairman of the White House Council on Environmental Quality to determine whether an infrastructure project qualified as a "high priority" within 30 days of receiving the request. *Id.* § 2. This determination was to be made based on considerations of the project's importance to the general welfare, value to the nation, environmental benefits, and other such factors deemed relevant by the Chairman. *Id.* For all high priority projects, the Chairman was directed to coordinate with the head of the relevant agency to establish expedited procedures and deadlines to complete the necessary environmental reviews and authorizations. *Id.* § 3. With respect to established deadlines not met, the head of the relevant agency was required to submit a written explanation to the Chairman explaining the cause for delay and outlining "concrete actions" taken by the agency to complete the review as expeditiously as possible. *Id.* It is worth noting that EO 13,766 never established particular deadlines for subject environmental reviews, and only mandated that the Chairman coordinate with the applicable federal agency to develop a timeline for that particular project.

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Secretary issue such authorizations. The Order also does not revoke the bureaus' delegated authority to issue authorizations necessary to "avoid conditions that might pose a threat to human health, welfare, or safety" and to "avoid adverse impacts to public land or mineral resources." *Id.* § 3(g). The Order also states that it does not "limit existing operations under valid leases." *Id.*

Additionally, the Order suspends the bureaus' delegated authority "[t]o grant rights of way, easements, or any conveyances of property or interests in property, including land sales or exchanges, or any notices to proceed under previous surface use authorizations that will authorize ground-disturbing activities." *Id.* § 3(c).

On January 25, 2021, the Senior Counselor to the Secretary, exercising the delegated authority of the Solicitor, issued a memorandum clarifying that Secretarial Order No. 3395 does not apply to actions on Indian lands. *See* Memorandum from Robert T. Anderson, Senior Counselor to the Sec'y, to Darryl LaCounte, Dir., Bureau of Indian Affairs, on Non-Application of Secretarial Order 3395 to Actions Relating to Indian Lands (Jan. 25, 2021).

Second, on January 27, 2021, President Biden signed Executive Order No. 14,008, "Tackling the Climate Crisis at Home and Abroad," 86 Fed. Reg. 7619 (Jan. 27, 2021). Section 208 of this executive order directs the Department to "pause new oil and natural gas leases on public lands or in offshore waters" while the Department completes "a comprehensive review and reconsideration of Federal oil and gas permitting and leasing practices." *Id.* at 7624.

The directed review of federal oil and gas leasing and permitting is broad in scope. The executive order instructs that the review should consider "the Secretary of the Interior's broad stewardship responsibilities over the public lands and in offshore waters, including potential climate and other impacts associated with oil and gas activities on public lands or in offshore waters." *Id.* at 7624–25. Furthermore, the executive order directs the Secretary to consider whether to adjust royalties on federal oil and natural gas "to account for corresponding climate costs." *Id.* at 7625.

The executive order does not direct the Department to complete this review within a specified time frame. Therefore, the "pause" on new oil and natural gas leases is indefinite.

The leasing moratorium is limited to federal public lands and offshore waters only. The moratorium does not apply to Indian leasing. It also does not suspend permitting of new oil and natural gas wells on existing federal leases.

D.C. Circuit Requires EIS for Dakota Access Pipeline but Does Not Order Shutdown

In *Standing Rock Sioux Tribe v. U.S. Army Corps of Engineers*, 985 F.3d 1032 (D.C. Cir. 2021), the U.S. Court of Appeals for the D.C. Circuit affirmed the district court's order vacating an easement issued by the U.S. Army Corps of Engineers (Corps) for the Dakota Access Pipeline (DAPL), but reversed the court's order to shut down the pipeline. The D.C. Circuit also agreed with a separate order of the district court that the Corps should have prepared an environmental impact statement (EIS) before issuing the easement. The district court's decisions were reported in Vol. XXXVII, No. 2 (2020) and Vol. XXXVII, No. 3 (2020) of this *Newsletter*.

The Corps and Dakota Access, LLC, the project proponent, appealed the district court's conclusion that the effects of the easement for DAPL's construction were "highly controversial," requiring an EIS. *Standing Rock Sioux*, 985 F.3d at 1042. The D.C. Circuit previously outlined the type of controversy that renders effects "highly controversial" in *National Parks Conservation Ass'n v. Semonite*, 916 F.3d 1075, 1083 (D.C. Cir. 2019). Particularly, the court identified "concrete objections" and criticisms from governmental agencies, consultants, and organizations with "on-point expertise." *Standing Rock Sioux*, 985 F.3d at 1043 (quoting *Nat'l Parks*, 916 F.3d at 1085–86). Further, in *National Parks*, the court explained that, when evaluating an agency's attempt to address these concerns, "[t]he question is not whether the [agency] attempted to resolve the controversy, but whether it succeeded." *Id.* (first alteration in original) (quoting *Nat'l Parks*, 916 F.3d at 1085–86).

The district court had relied on *National Parks* to find the effects of the DAPL to be "highly controversial." *See id.* The appellants contended that, in doing so, the "district court applied the wrong legal standard." *Id.* The Corps sought to distinguish the two cases, first arguing that its response to criticism was "not superficial." *Id.* (internal quotation marks omitted). The D.C. Circuit disagreed, finding "[t]he decisive factor is not the volume of ink spilled . . . , but whether the agency has . . . convinced the court that it has materially addressed and resolved serious ob-

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.

jections to its analysis . . . ." *Id.* The Corps also attempted to distinguish the tribes from "disinterested public officials"; however, the court rejected this logic and emphasized that tribes are sovereign nations with a distinguished relationship with the U.S. government. *Id.* at 1043–44.

After finding that the district court properly relied on *National Parks*, the D.C. Circuit upheld the district court's conclusion that the Corps did not adequately resolve controversies over the effectiveness of DAPL's leak detection system, DAPL's operator safety record, the Corps' consideration of winter conditions, and the worst-case discharge estimate. *Id.* at 1044–49. Additionally, the court rejected the appellants' contention that the easement decision cannot be considered highly controversial because of the significantly low spill risk and the minimized consequences of a spill attributable to DAPL's underground location. *Id.* at 1049–50. The court reasoned that "[d]oing away with the obligation to prepare an EIS whenever a project presents a low-probability risk of very significant consequences would wall off a vast category of major projects from [the National Environmental Policy Act's] EIS requirement." *Id.* at 1049. The court accordingly held that the Corps should have prepared an EIS. *Id.*

With this holding, the D.C. Circuit affirmed the district court's decision vacating the Corps' easement; however, the court set aside the district court's order that the pipeline be shut down and emptied of oil. *Id.* at 1050–54. The court rejected the tribes' argument that vacatur of the underlying easement required the court to suspend pipeline operations. *Id.* at 1054. The court reasoned that ordering shutdown of pipeline operations was, in fact, an injunction that must be evaluated under the four-factor test for injunctive relief. *Id.* at 1053 (citing *Monsanto Co. v. Geertson Seed Farms*, 561 U.S. 139 (2010)). Because the district court did not undertake this analysis, the D.C. Circuit determined the lower court could not order shutdown of the pipeline.

Interestingly, the D.C. Circuit recognized that, without a valid easement, "the pipeline will remain an encroachment, leaving the precise consequences of vacatur uncertain." *Id.* at 1054. The court left the question of "how and on what terms the Corps will enforce its property rights" to the Corps to decide and noted the Corps' decision could be challenged under the Administrative Procedure Act. *Id.*

Pair of Solicitor's Opinions Address Offshore Permitting and Leasing

In the waning days of the Trump administration, Solicitor of the Interior Daniel H. Jorjani issued two opinions related to offshore oil and gas permitting and leasing.

First, on January 11, 2021, the Solicitor issued Opinion No. M-37061, "Bureau of Safety and Environmental Enforcement's Obligations to Consider Applications for Permits to Drill/Modify in a Timely Manner." This opinion advised the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) that they should issue determinations on complete applications for permits to drill (APDs) within 75 days absent a compelling justification for a longer period. The Solicitor reasoned that, under the Administrative Procedure Act and the Outer Continental Shelf Lands Act (OCSLA), "lessees have a reasonable expectation that their complete applications will receive a timely determination and that the government has a duty to issue a timely determination." *Id.* at 3. The Solicitor acknowledged a lack of a "bright line rule to determine what constitutes a reasonable amount of time for an agency to complete a required action" but noted that "BSEE's current practice is to decide on almost all complete APDs within 70 days, and routinely within 30 days." *Id.* at 5.

Second, on January 13, 2021, the Solicitor issued Opinion No. M-37062, "Secretarial Discretion in Promulgating a National Outer Continental Shelf Oil and Gas Leasing Program." In this opinion, the Solicitor advised BOEM on whether it must promulgate a National Outer Continental Shelf Oil and Gas Leasing Program (National Program or Program). The Solicitor advised that although

> section 18 of [OCSLA] does not expressly prohibit the Secretary from not promulgating a Program, . . . the better interpretation of section 18 is that the Secretary must promulgate a National Program and that such a Program may consist of a schedule with as few as two lease sales, but no fewer, as long as the Program meets the requirements of section 18.

Id. at 1. The Solicitor based this recommendation on the language of OCSLA, its legislative history, and subsequent case law. *Id.* at 2–4. Furthermore, the Solicitor concluded that although the Secretary may cancel one or more lease sales after finding the cancellation(s) to be "an insignificant Program revision," the Secretary may not "cancel all sales en masse if that were to cause a period of time in which the Secretary was not 'maintaining' a Program" and "may not cancel so many sales as to diminish the Program's schedule of lease sales to fewer than two lease sales." *Id.* at 6.

Leasing in Arctic National Wildlife Refuge Initially Allowed to Proceed

In *Gwich'in Steering Committee v. Bernhardt*, Nos. 3:20-cv-00204, 3:20-cv-00205, 3:20-cv-00223, 2021 WL 46703 (D. Alaska Jan. 5, 2021), the U.S. District Court for the District of Alaska declined to preliminarily enjoin the Bureau of Land Management (BLM) from issuing oil and gas leases in the Arctic National Wildlife Refuge. The court found that the plaintiffs had not established a likelihood of irreparable harm. *Id.* at *10.

Although leasing would allow lessees to engage in ground-disturbing activities, the court observed that exploration activities were not anticipated for another two years and would be subject to additional analysis under the National Environmental Policy Act. *Id.* at *8. Therefore, the court determined the plaintiffs had not met their burden to obtain a preliminary injunction. The court acknowledged that the plaintiffs could seek preliminary injunctive relief if BLM approved ground-disturbing activities before the court ruled on the merits of BLM's leasing decision. *Id.* at *10.

BLM's NEPA Review for Wyoming Lease Sales Fails the Hard Look Test for the Second Time

On November 13, 2020, the U.S. District Court for the District of Columbia held the Bureau of Land Management's (BLM) supplemental environmental assessment (EA) for federal oil and gas leases in Wyoming was deficient because it did not comply with the National Environmental Policy Act (NEPA). *See WildEarth Guardians v. Bernhardt*, No. 1:16-cv-01724 (D.D.C. Nov. 13, 2020).

This decision marks the second time this court has rejected BLM's environmental analysis prepared for the leasing decisions. The case began when environmental groups sued BLM after it issued 473 federal oil and gas leases in Wyoming, Utah, and Colorado; BLM sold the leases at 11 sales between 2015 and 2016. The court decided to tackle the sufficiency of the nine EAs that BLM prepared for the Wyoming lease sales first and, in March 2019, held those EAs violated NEPA by failing to properly quantify and assess the impacts of greenhouse gas emissions. *See WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 67–78 (D.D.C. 2019). The court remanded the EAs to BLM for further review and enjoined BLM from issuing applications for permits to drill (APDs) on the challenged leases. *Id.* at 85; *see also* Vol. XXXVI, No. 2 (2019) of this *Newsletter*.

Following remand, BLM completed a supplemental EA for the Wyoming lease sales (Wyoming Supplemental EA) and issued a new finding of no significant impact (FONSI) for the challenged leases. *WildEarth Guardians*, No. 1:16-cv-01724, slip op. at 9. The court concluded that the Wyoming Supplemental EA failed, again, to comply with NEPA. This time, the issues were more discrete.

First, the court held that BLM arbitrarily ignored reasonably foreseeable development scenarios when evaluating cumulative effects because it did not consider foreseeable oil and gas lease sales or other BLM actions outside of Wyoming. *Id.* at 12–19. Second, the court held that BLM improperly analyzed only yearly emission rates from anticipated development on the leases, rather than the total emissions from the life of the project, to understand the total impact of anticipated development. *Id.* at 19–22.

Third, the court rejected BLM's calculated emission rates after finding that BLM arbitrarily assumed that all federal lands open to leasing would produce oil and gas. *Id.* at 23. BLM calculated a per-acre emission factor by dividing the total emissions estimates by the area open to leasing, instead of the area actually leased. *Id.* The court found that this calculation dilutes the "emission per acre" metric because the emissions per acre are lower when emissions are divided by all acreage instead of only acreage that has been leased. *Id.* at 24–25. BLM also erred by using a different methodology for calculating cumulative emissions, which made it difficult to compare cumulative emissions to direct and indirect emissions. *Id.*

Fourth, BLM made conflicting statements about whether it prepared and considered a carbon budget analysis. *Id.* at 25–28. The court held that BLM must either explain why a carbon budget analysis would not contribute to its decision making or it must actually consider a carbon budget when making decisions. *Id.* at 27. Finally, BLM made several mathematical errors throughout the Wyoming Supplemental EA that the court held rendered the analysis arbitrary and capricious and indicated that it was sloppy and rushed. *Id.* at 28–30.

The court denied the plaintiffs' requests to vacate the leases. Instead, the court remanded the Wyoming Supplemental EA analysis to BLM for another opportunity to correct deficiencies. *Id.* at 34. And, as in its March 19, 2019, decision, the court enjoined BLM from issuing APDs for the challenged leases while it corrects the Wyoming Supplemental EA and the FONSIs. *Id.* BLM and the intervenor-defendants have appealed the court's November 13, 2020, decision. *See WildEarth Guardians v. Bernhardt*, Nos. 21-5006, 21-5020, 21-5021, 21-5023, 21-5024 (D.C. Cir. consolidated Jan. 28, 2021).

Uinta Basin Oil and Gas Leases Set Aside

In *Rocky Mountain Wild v. Bernhardt*, No. 2:19-cv-00929, 2020 WL 7264914 (D. Utah Dec. 10, 2020), the U.S. District Court for the District of Utah remanded oil and gas leases sold in December 2017 and June 2018 sales to the Bureau of Land Management (BLM) for further analysis of leasing near Dinosaur National Monument, on lands with wilderness characteristics, or in Areas of Critical Environmental Concern (ACEC). The court held that the administrative record did not disclose how and why BLM elected to lease in these areas, but the court otherwise upheld BLM's analysis of environmental impacts of leasing, including on greenhouse gas emissions.

In the environmental assessment supporting the sale, BLM analyzed two alternatives, a lease alternative and a no-lease alternative. *Id.* at *8. Commenters, however, had proposed deferring parcels within the viewshed of Dinosaur National Monument and parcels that overlap with lands with wilderness characteristics and an ACEC. *Id.* The court determined that the record was "unclear as to how much analysis occurred" to determine whether and how to lease near Dinosaur National Monument, in areas with wilderness characteristics, and in ACECs. *Id.* at *9.

Notably, the court upheld BLM's analysis of other leasing impacts. The court accepted BLM's analysis of potential ozone impacts, finding that BLM reasonably relied on a qualitative assessment after acknowledging that quantitative models could not reliably predict wintertime ozone. *Id.* at *4–5. The court also upheld BLM's analysis of potential impacts to greenhouse gas emissions. The court found that BLM properly relied on a quantitative assessment of per-well emissions estimates and properly estimated downstream emissions. *Id.* at *5. The court also accepted BLM's assessment of cumulative impacts to greenhouse gas emissions, finding that BLM acted properly by "generally identif[ying] the broad global context within which this decision fits." *Id.* at *7.

Finally, the court held that BLM's leasing decision did not violate the Federal Land Policy and Management Act (FLPMA) despite prior exceedances of the 8-hour ozone National Ambient Air Quality Standard in the Uinta Basin. *See id.* at *3. The plaintiffs had argued that leasing violated FLPMA's requirement that agencies ensure "compliance with applicable pollution control laws." *Id.* at *11 (quoting 43 U.S.C. § 1712(c)(8)). The court held that BLM properly leased with notices providing that BLM may impose best management practices and may require additional air quality analysis. *Id.* at *12.

Both BLM and the plaintiffs have appealed the holding. *See Rocky Mountain Wild v. Bernhardt*, Nos. 21-4019, 21-4020 (10th Cir. filed Feb. 16, 2021).

ONRR Finalizes Amendments to Royalty Valuation and Civil Penalty Rules

On January 15, 2021, the Office of Natural Resources Revenue (ONRR) published revisions to its royalty valuation regulations at 30 C.F.R. pt. 1206 for federal oil and gas and federal and Indian coal, and its civil penalty regulations at 30 C.F.R. pt. 1241. *See* ONRR 2020 Valuation Reform and Civil Penalty Rule, 86 Fed. Reg. 4612 (Jan. 15, 2021) (to be codified at 30 C.F.R. pts. 1206, 1241). The rules were scheduled to become effective on February 16, 2021, and require that lessees conform to the amended valuation requirements at 30 C.F.R. pt. 1206 beginning with production that occurs on and after May 1, 2021.

On February 12, 2021, ONRR published a notice delaying the rules' effective date for 60 days until April 16, 2021. *See* 86 Fed. Reg. 9286 (Feb. 12, 2021). ONRR also opened a 30-day comment period, through March 15, 2021, "on any issue of fact, law, or policy raised by the [rules]," including 10 questions listed in the notice. *Id.* at 9287. The notice does not acknowledge the May 1, 2021, compliance deadline.

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through groundwater before reaching a water of the United States," the guidance memorandum "provides EPA's guidance to assist the regulated community and permitting authorities with applying the *Maui* holding in existing CWA NPDES permit programs and authorized state programs." Guidance Memorandum at 2–3. EPA notes that such guidance is necessary because while the *Maui* decision "did not change the overall statutory or regulatory structure of the NPDES permit program," it did identify "an additional analysis that should be conducted in certain factual scenarios to determine whether an NPDES permit is required." *Id.* at 3.

The *Maui* guidance memorandum first describes the conditions that must be satisfied before the obligation to have an NPDES permit is triggered, which the *Maui* opinion did not modify: (1) there must be an actual discharge of a pollutant to a water of the United States, and (2) such discharge must be from a point source. *Id.* at 3–4. The guidance memorandum then explains its analysis of three issues that are relevant to determining whether a discharge to groundwater is the "functional equivalent of a direct discharge from a point source into navigable waters." First, "[a]n actual discharge of a pollutant to a water of the United States is a threshold condition that must be satisfied before the need for an NPDES permit is triggered." *Id.* at 4. EPA explained that "a release of pollutants from a point source that occurs near a water of the United States does not by itself trigger the NPDES permit requirement." *Id.* Specifically, the *Maui* decision

> did not instruct NPDES permitting authorities to *assume* that discharges to groundwater that occur in the vicinity of a jurisdictional water are the "functional equivalent" of direct discharges to that water. . . . [S]uch discharges may never reach jurisdictional waters . . . [due to] characteristics of the pollutant itself and the nature of the subsurface aquifer and hydrogeology.

Id. Therefore, a technical analysis that supports an allegation that an unpermitted discharge has occurred is necessary, and an allegation alone would generally not require the permitting authority to investigate. *Id.* at 5.

Second, the discharge must be from a point source to trigger NPDES permitting requirements. *Id.* EPA explained that the threshold requirement of a release through a point source applies equally to discharges through groundwater, and that the *Maui* decision "reinforces this basic principle." *Id.* Specifically, the Supreme Court affirmed that the states maintain their "traditional regulatory authority" over nonpoint source pollution and groundwater. Accordingly, in *Maui*, the Court "affirmed that the CWA still requires a discharge of a pollutant from a point source to a water of the United States. If the pollutant travels through groundwater first, the same point source requirement applies . . . ." *Id.*

Third, "[o]nly a subset of discharges of pollutants to groundwater that ultimately reach a water of the United States are the 'functional equivalent' of a direct discharge to a water of the United States." *Id.* at 6. Whether a discharge via groundwater is the functional equivalent of a direct discharge will depend on the factors identified in *Maui*, and science will inform the effect of time and distance traveled on a discharge to determine whether it is the functional equivalent of a direct discharge. "Pollutants may be discharged from a point source and migrate through a system that treats, provides uptake of, dilutes, or retains pollutants before the pollutant reaches the water of the United States," or may "reach[] a water of the United States in the same or nearly the same chemical composition and concentration . . . [,] more like a direct discharge to the jurisdictional water." *Id.* Historically, very few NPDES permits have been issued for discharges that travel through groundwater, particularly "[c]ompared with the hundreds of thousands of NPDES permits that have been issued [for discharges] since the inception of the program . . . ." *Id.* As a result, "EPA anticipates that the issuance of such permits will continue to be a small percentage of the overall number of NPDES permits issued following application of the Supreme Court's 'functional equivalent' analysis." *Id.* at 6–7.

Finally, EPA identified another factor in addition to those identified by *Maui* that may be relevant to a functional equivalent analysis: "the design and performance of the system or facility from which the pollutant is released." *Id.* at 7. The guidance memorandum instructs the owner or operator of a facility or system that is designed and performs to discharge pollutants from a point source through groundwater and into a water of the United States to contact its permitting authority to determine whether a permit is required. *Id.* at 8.

Ninth Circuit Vacates Agency Approval of Offshore Drilling Project Due in Part to Lack of Full Consideration of Emissions and Climate Impacts of Project

In a December 7, 2020, opinion, the U.S. Court of Appeals for the Ninth Circuit vacated the Bureau of Ocean Energy Management (BOEM) and U.S. Fish and Wildlife Service's (FWS) approval of a proposed offshore drilling and production facility off the coast of Alaska. *Ctr. for Biological Diversity v. Bernhardt*, 982 F.3d 723 (9th Cir. 2020). The project proponent sought to construct an offshore facility, referred to as the "Liberty project," that would be fully submerged in federal waters in the Beaufort Sea, and within the Outer Continental Shelf (OCS) of the United States. *Id.* at 731. BOEM, housed within the U.S. Department of the Interior, administers the leasing of federal land within the OCS for oil and gas production. Permitting of the project required approval under the National Environmental Policy Act (NEPA), the Endangered Species Act (ESA), and the Marine Mammal Protection Act (MMPA), the latter two requiring BOEM to consult with FWS. *Id.* at 732. FWS then must prepare a biological opinion (BiOp) to determine whether the agency's proposed action will jeopardize a species, and provide an "incidental take statement" if the project will result in the "incidental take" of members of a threatened or endangered species. *Id.* BOEM and FWS completed this process, with BOEM preparing an environmental impact statement (EIS) as required by NEPA, and FWS preparing a BiOp. Relying on the EIS and BiOp, BOEM approved the Liberty project. The Center for Biological Diversity and other conservation organizations (collectively, CBD) challenged the approval, arguing the agencies failed to comply with the requirements of NEPA, the ESA, and the MMPA by (1) arbitrarily and capriciously estimating the environmental consequences of alternatives analyzed in the EIS, (2) FWS producing a legally inadequate BiOp, and (3) BOEM relying on the unlawful BiOp. *Id.* The court addressed each of these arguments and ultimately vacated BOEM's approval.

First, the court summarized the requirements of NEPA, including that an EIS must include a "no-action" alternative that is "informed and meaningful" and does not "minimize negative side effects." *Id.* at 734–35. The court found that BOEM properly used the same methodology to calculate the greenhouse gas emissions resulting from the Liberty project and the no-action alternative when it "used a market-simulation model to predict the greenhouse gas emissions for energy sources that would substitute for the oil not produced at Liberty." *Id.* at 736. Specifically, the model took into account market changes if the Liberty project was developed, and if it was developed, none of the potential emissions in other parts of the United States estimated under the no-action alternative would result. *Id.*

By contrast, the court agreed with CBD that "BOEM arbitrarily failed to include emissions estimates resulting from foreign oil consumption in its analysis of the no-action alternative." *Id.* The court summarized that the EIS found that the no-action alternative would result in more emissions "because the oil substituted for the oil not produced at Liberty [would] come from places with 'comparatively weaker environmental protection standards associated with exploration and development of the imported product and increased emissions from transportation.'" *Id.* The model used by BOEM assumed foreign oil consumption would "remain static, whether or not oil is produced at Liberty," which was contrary to basic economic principles pursuant to which an increase in global supply will reduce prices, and due to such reduced prices foreign consumers will buy and consume more oil. *Id.* This flaw in the model and the lack of information or estimates of changes in foreign oil consumption in BOEM's analysis caused the EIS not to adequately consider the indirect effects of a proposed action, in violation of NEPA and leading to the "counterintuitive" conclusion that "*not* drilling will result in more carbon emissions than drilling." *Id.* at 739. As a result, the court found that BOEM acted arbitrarily and capriciously because it reached a decision that was "so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Id.* (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)). BOEM was required to at least explain why an estimate of changes in foreign oil consumption was not possible and how foreign oil consumption could affect downstream emissions. *Id.*

> [T]he EIS "should have either given a quantitative estimate of the downstream greenhouse gas emissions" that will result from consuming oil abroad, or "explained more specifically why it could not have done so," and provided a more thorough discussion of how foreign oil consumption might change the carbon dioxide equivalents analysis.

Id. at 740 (quoting *Sierra Club v. FERC*, 867 F.3d 1357, 1374 (D.C. Cir. 2017)).

The court next found that the proposed mitigation measures that FWS proposed in its BiOp were "too vague to enforce" because they were "general" and not specific and definite commitments to develop mitigation strategies for preventing negative impacts to polar bears, and specifically denning mothers and cubs. *Id.* at 747. Therefore, FWS's reliance on the indefinite mitigation measures to conclude that polar bears' critical habitat would not be adversely modified by the Liberty project was arbitrary and capricious. However, the court also determined that FWS did not rely on the mitigation measures to reach its no-jeopardy and no-adverse-modification findings because FWS had concluded that the Liberty project would not significantly impact polar bears, with or without the mitigation measures. *Id.* at 748.

Finally, the court found that FWS "unlawfully failed to specify the amount and extent of 'take' in its incidental take statement." *Id.* The court explained that the purpose of the incidental take statement is to specify the amount of take that may occur, and to include non-compliance triggers requiring re-consultation with FWS. *Id.* FWS's incidental take statement did not incorporate triggers for re-consultation requirements that were described in the BiOp. Specifically, although the BiOp provided that a "level[] of interaction with polar bears" that "increases significantly or results in chronic, repeated interference with normal bear behavior" would require re-consultation, and thus was a take, the incidental take statement failed to provide an estimate for such take. *Id.* at 750. The court thus held that FWS's incidental take statement violated the ESA "[b]ecause FWS contemplated that the harassment and disturbances polar bears will suffer could trigger re-consultation with FWS and did not quantify the nonlethal take that polar bears are expected to face (or explain why it could not do so) . . . ." *Id.*

As a result of the court's findings of the agencies' deficiencies in the NEPA and ESA processes, the court vacated BOEM's approval of the Liberty project, and remanded back to the agency to effectively restart the process. *Id.* at 751.

CONGRESS / FEDERAL AGENCIES – GENERAL

John H. Bernetich
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– Reporters –

FWS Clarifies That MBTA's Criminal Penalties Do Not Apply to Incidental Takes

On January 7, 2021, the U.S. Fish and Wildlife Service (FWS) issued a final rule clarifying that the Migratory Bird Treaty Act's (MBTA) 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. *See* Regulations Governing Take of Migratory Birds, 86 Fed. Reg. 1134, 1137 (Jan. 7, 2021) (to be codified at 50 C.F.R. pt. 10). The rule was slated to become effective on February 8, 2021, but the Biden administration has postponed the effective date to March 8, 2021, to consider public comments, which are due by March 1, 2021. *See* Regulations Governing Take of Migratory Birds; Delay of Effective Date, 86 Fed. Reg. 8715 (Feb. 9, 2021).

The MBTA makes it a crime to pursue, hunt, take, capture, or kill any migratory bird or any migratory bird nest or egg. 16 U.S.C. § 703(a). For years, federal courts disagreed on the scope of the MBTA's applicability: some courts ruled that the MBTA prohibited only "intentional" acts meant to harm a migratory bird, while others ruled that a criminal conviction under the MBTA did not require a showing of "specific intent" to take a migratory bird. *See United States v. CITGO Petroleum Corp.*, 801 F.3d 477, 488–89 (5th Cir. 2015) (ruling that the MBTA prohibits only "deliberate acts done directly and intentionally to migratory birds"); *United States v. FMC Corp.*, 572 F.2d 902, 906 (2d Cir. 1978) (specific intent to take a migratory bird is not required).

In 2017, the Solicitor of the Interior issued a legal opinion concluding that 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, "The Migratory Bird Treaty Act Does Not Prohibit Incidental Take" (Dec. 22, 2017) (M-37050); *see* Vol. XXXV, No. 1 (2018) of this *Newsletter*. The Trump administration's M-Opinion repealed Solicitor's Opinion M-37041, "Incidental Take Prohibited Under the Migratory Bird Treaty Act" (Jan. 10, 2017), issued in the waning days of the Obama administration and concluding that the MBTA does prohibit incidental take. The Trump administration also issued guidance implementing M-37050. That guidance clarified, for example, that homeowners with knowledge that protected birds are nesting in their chimney would not be liable for lighting a fire that destroyed the nests if the purpose of the fire was to heat the house and not to intentionally destroy the nests. *See* FWS, "Guidance on the Recent M-Opinion Affecting the Migratory Bird Treaty Act" (Apr. 11, 2018).

In February 2020, FWS published a proposed rule to codify the conclusion from M-37050. *See* Regulations Governing Take of Migratory Birds, 85 Fed. Reg. 5915 (proposed Feb. 3, 2020) (to be codified at 50 C.F.R. pt. 10); *see also* Vol. XXXVII, No. 1 (2020) of this *Newsletter*. In August 2020, however, a federal district court struck down M-37050 as contrary to the statute. *Nat. Res. Def. Council, Inc. v. DOI*, 478 F. Supp. 3d 469 (S.D.N.Y. 2020).

Despite the adverse court ruling, FWS published its final rule on January 7, 2021, "adopt[ing] the conclusion" of M-37050 and codifying that the MBTA's prohibition on pursuing, hunting, taking, capturing, or killing migratory birds "appl[ies] only to actions directed at migratory birds." 86 Fed. Reg. at 1134. The rule further provides that "injury to or mortality of migratory birds that results from, but is not the purpose of, an action (i.e., incidental taking or killing) is not prohibited by the [MBTA]." *Id.* at 1165 (to be codified at 50 C.F.R. § 10.14).

The decision to postpone the MBTA rule is consistent with the Biden administration's Executive Order No. 13,990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," 86 Fed. Reg. 7037 (Jan. 20, 2021). Concurrent with the executive order, the administration published a list of regulations and agency actions that the heads of the relevant agencies will review for consistency with Executive Order No. 13,990. *See* Fact Sheet, White House, "List of Agency Actions for Review" (Jan. 20, 2021). The January 2021 MBTA final rule and M-37050 are among the agency actions listed for review.

On January 20, 2021, the Biden White House issued a memorandum providing that, with respect to all rules that have been published in the *Federal Register* but have not yet taken effect (such as the MBTA rule), agencies should "consider postponing the rules' effective dates for 60 days . . . for the purpose of reviewing any questions of fact, law, and policy the rules may raise." OMB Memorandum for Heads of Exec. Dep'ts & Agencies, "Regulatory Freeze Pending Review," 86 Fed. Reg. 7424 (Jan. 20, 2021). Additionally, if a rule's effective date is postponed, agencies should "consider opening a 30-day comment period" and, if the agency determines, further delay the rule's effective date beyond the 60-day period. *Id.* Following any delay in a rule's effective date, the agency may take any action in accordance with the Administrative Procedure Act.

Additionally, the new Congress may seek to override the rule by invoking the Congressional Review Act (CRA), 5 U.S.C. §§ 801–808, which allows Congress to "disapprove" any rule finalized during the final days of a presidential administration. If each house of Congress approves a resolution disapproving the rule with a simple majority and the resolution is signed by the President, the January 2021 final rule would be rescinded and FWS would be prohibited from reissuing a rule in "substantially the same form" without legislative authorization. These circumstances make it unclear when the January 2021 final rule will become effective, if ever.

Congress Passes Energy Act Incentivizing Increased Development of Renewable Energy on Federal Land

The recent COVID-19 stimulus relief bill, the Consolidated Appropriations Act, 2021, became law on December 27, 2020. *See* Pub. L. No. 116-260, 134 Stat. 1182 (2020). As part of the Appropriations Act, President Trump also signed the Energy Act of 2020 (Energy Act) and included provisions aimed at incentivizing renewable energy development in the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (Taxpayer Act). *See* Pub. L. No. 116-260, Divs. Z (Energy Act), EE (Taxpayer Act).

The Taxpayer Act extended certain federal tax credits for renewable energy projects that were scheduled to phase out. It extended the construction deadline for the production tax credit (PTC) for all wind projects for one year, until January 1, 2022, and extended the investment tax credit (ITC) for offshore wind farms until December 31, 2025. *See* Taxpayer Act §§ 131, 204. The Taxpayer Act also extended the ITC phasedown schedule for solar facilities by two years. *Id.* § 132.

The Energy Act contains provisions specifically focused on expediting and increasing approval and development of both solar and wind projects on Bureau of Land Management (BLM) and U.S. Forest Service (Forest Service) lands. It tasks the U.S. Department of the Interior (Interior) with establishing a new Renewable Energy Coordination Office to "establish and implement a program to improve Federal permit coordination" for wind, solar, and geothermal energy projects on BLM and Forest Service land. Energy Act § 3102. As part of the Renewable Energy Coordination Office, the Energy Act directs the Secretary of the Interior to enter into a memorandum of understanding with the Secretary of Agriculture, the Administrator of the U.S. Environmental Protection Agency, the Secretary of Defense, and state governors to facilitate permit coordination among federal and state regulators. *Id.* The Energy Act also provides the Secretary of the Interior with greater discretion to reduce federal rental rates and other fees. *Id.* § 3103. And perhaps most importantly, the Energy Act sets a specific target for the development of renewable projects on federal land. It requires the Secretary of the Interior, in consultation with the Secretary of Agriculture, to set national goals for wind, solar, and geothermal energy production on federal land by September 1, 2022, and requires that Interior seek to permit at least 25 gigawatts of electricity from wind, solar, and geothermal projects by 2025. *Id.* § 3104.

Finally, separate from the Appropriations Act, the Internal Revenue Service issued Notice 2021-05, which extends the Continuity Safe Harbor for offshore wind projects and renewable projects on federal land from 4 years to 10 years. *See* Notice 2021-05 § 4. This will allow developers of renewable projects on federal lands to claim federal tax credits on these projects if the project is placed into service within 10 years after beginning construction. This extension, combined with extensions of the PTC and ITC under the Taxpayer Act and the streamlining provisions of the Energy Act, likely will incentivize proposed development of renewable projects on federal land.

Forest Service Finalizes Amendments to NEPA Regulations

On November 19, 2020, the U.S. Forest Service (Forest Service) published a final rule amending the agency's regulations implementing the National Environmental Policy Act (NEPA). *See* NEPA Compliance, 85 Fed. Reg. 73,620 (Nov. 19, 2020) (to be codified at 36 C.F.R. pt. 220). The Forest Service last updated its NEPA regulations in 2008. The Forest Service's NEPA amendments create new categorical exclusions (CEs), revise existing CEs, and add a determination of NEPA adequacy (DNA) provision.

The Forest Service estimates that it currently has a backlog of more than 5,000 applications for the issuance or renewal of special use permits, and it receives, on average, 3,000 applications for new special use permits annually. *See* NEPA Compliance, 84 Fed. Reg. 27,544 (proposed June 13, 2019) (to be codified at 36 C.F.R. pt. 220). Under the prior Forest Service regulations, the agency was required to develop an environmental assessment (EA) in order to process a large percentage of these applications or to approve development under existing special use authorizations. The Forest Service's NEPA amendments will create needed efficiencies for the agency as well as special use permit applicants and holders.

For example, new CE (e)(22) will apply to the "[c]onstruction, reconstruction, decommissioning, or disposal of buildings, infrastructure, or improvements at an existing recreation site," including those managed under special use authorizations. 36 C.F.R. § 220.6(e)(22). Recreation sites include campgrounds and camping areas, lodging resorts, day use areas, fishing sites, and ski areas. *Id.* The Forest Service estimates that it "provides access to roughly 29,700 recreation sites." 85 Fed. Reg. at 73,626. Many of these facilities were constructed decades ago and are in desperate need of maintenance and other improvements. The new CE (e)(22) will help "increase efficiency in NEPA compliance for proposed actions to improve existing recreation sites that are in decline or pose safety or resource concerns." *Id.* In this manner, CE (e)(22) is an important recognition by the Forest Service that providing well-maintained and high-quality facilities on National Forest System (NFS) lands effectuates one of the Forest Service's fundamental goals—providing the infrastructure necessary to facilitate public access and use of NFS lands.

The Forest Service also adopted DNA procedures. 36 C.F.R. § 220.4(j). DNAs allow an agency to rely on existing NEPA reviews that already adequately analyze the impacts of a proposed action. The U.S. Department of the Interior and other federal departments and agencies have effectively used the DNA process to avoid redundancy in the NEPA process. The Forest Service's NEPA amendments codify a DNA checklist almost identical to the checklist currently provided in the Bureau of Land Management's (BLM) *NEPA Handbook*. *See* BLM, *NEPA Handbook H-1790-1*, at 23 (Rel. 1-1710 Jan. 30, 2008). The new DNA procedure will make the Forest Service's NEPA processes more efficient by allowing it to rely on existing analyses where appropriate. This could help, for example, when analyzing proposed projects within existing special use authorizations where the impacts were previously analyzed in a broader NEPA document addressing the same or similar actions within the permitted area, or when approving similar actions (such as races or special events) occurring on the same lands in successive years.

A few of the Forest Service's proposed amendments drew substantial opposition, including to proposed revisions to its scoping requirements. The Forest Service's current NEPA regulations require scoping "for all Forest Service proposed actions, including those that would appear to be categorically excluded from further analysis and documentation in an EA or an [environmental impact statement (EIS)]." 36 C.F.R. § 220.4(e)(1). The Forest Service proposed to require scoping only for projects analyzed in an EIS and to allow responsible officials to determine whether to conduct scoping for projects analyzed using CEs and EAs. 84 Fed. Reg. at 27,545, 27,553. The Forest Service ultimately withdrew the proposed amendment and indicated it would reconsider revisions to the Forest Service's scoping requirements in association with the Forest Service's review of its NEPA procedures as directed by the Council on Environmental Quality's (CEQ) recently revised regulations. 85 Fed. Reg. at 73,621. Given the uncertainty surrounding the new CEQ regulations in light of the administration change, it is unclear when and if the Forest Service will undertake this review.

The majority of the Forest Service's NEPA amendments, including the two provisions discussed above, appear likely to remain as finalized. The Biden White House did not include the Forest Service NEPA rule on the recent list of regulations and agency actions that agencies will review for consistency with Executive Order No. 13,990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," 86 Fed. Reg. 7037 (Jan. 20, 2021). *See* Fact Sheet, White House, "List of Agency Actions for Review" (Jan. 20, 2021). And the one lawsuit that has been filed to date challenging the Forest Service's NEPA rule challenges the adoption of three specific CEs: CE (e)(25), which applies to logging projects up to 2,800 acres; CE (e)(24), which applies to construction of up to two miles of road; and CE (e)(3), which applies to special use authorizations affecting up to 20 acres of land. *See* Complaint, *Clinch Coal. v. U.S. Forest Serv.*, No. 2:21-cv-00003 (W.D. Va. Jan. 8, 2021), 2021 WL 119073.

ALABAMA – OIL & GAS

Benjamin Y. Ford
– Reporter –

Alabama Oil and Gas Board Amends Regulations Concerning Forced Pooling of "Unlocated" or "Undiscovered" Owners

Effective January 14, 2021, the rules and regulations of the State Oil and Gas Board of Alabama (OGB) were amended with respect to the pleading and practice of obtaining orders force pooling "unlocated" or "undiscovered" owners within a proposed drilling or production unit. The forced pooling of units is statutorily authorized by Ala. Code § 9-17-13 and administered via chapters 400-7-1 and 400-7-2 of the *State Oil and Gas Board of Alabama Administrative Code*. Although not previously codified, the existing practice of the OGB requires that an operator seeking to force pool all tracts and interests within a unit make a good-faith effort to locate and notify all owners of unleased or nonparticipating interests (i.e., "nonconsenting owners"). Because this established practice was not expressly required in the OGB's written rules, at hearings operators would often be forced to make "on the fly" evidentiary showings of their good-faith efforts.

Pursuant to added Rule 400-7-1-.06(4), an operator is now required to expressly state in its petition for forced pooling that the subject unit contains interests of an unlocated or undiscovered nonconsenting owner. Ala. Admin. Code r. 400-7-1-.06(4). In such an event, added Rule 400-7-2-.01(8) requires that an operator "submit evidence sufficient to show to the [OGB] that petitioner made a diligent effort to *identify* the unlocated or undiscovered nonconsenting owner and made a diligent effort to *locate* and discover the nonconsenting owner." *Id.* r. 400-7-2-.01(8) (emphasis added). Evidence that the OGB may require to make such a showing includes:

(a) an attestation of title and ownership relating to the nonconsenting owner's interest given by a person qualified to render opinions on title to real property in Alabama;

(b) copies of pertinent portions of title opinions, if any are available, prepared by a licensed Alabama attorney relating to the tract or interest being force pooled;

(c) a copy of the most recent source or sources of title from which the nonconsenting owner's interest is derived;

(d) sworn Affidavits of descent or heirship, if applicable, to a determination of the nonconsenting owner's interest; and

(e) such other evidence that the [OGB], Supervisor or Hearing Officer may deem proper and sufficient to show that the petitioner has identified the unlocated or undiscovered nonconsenting owner and made a diligent effort to locate the unlocated or undiscovered nonconsenting owner.

Id.

Note that these new rules do not authorize the imposition of a "risk compensation" fee against such unlocated or undiscovered owners. Rather, a risk compensation fee can only apply as to located owners and only when existing statutory requirements are met. *See* Ala. Code § 9-17-13(c); Ala. Admin. Code r. 400-7-1-.11(4)(e).

ARIZONA – MINING

Paul M. Tilley
– Reporter –

Arizona Department of Environmental Quality Amends Clean Air Act Rules

The Arizona Department of Environmental Quality (ADEQ) submitted its final notice of rulemaking to amend its existing rules specific to emission statements for stationary sources emitting ozone precursors, nitrogen oxides (NOx) and volatile organic compounds (VOCs). 26 Ariz. Admin. Reg. 3092 (Dec. 4, 2020). The rulemaking comes as the result of the U.S. Environmental Protection Agency (EPA) placing part of Yuma County, Arizona, in "nonattainment" for the 2015 Ozone National Ambient Air Quality Standards in June 2018. *Id.* The designation triggered a requirement under the Clean Air Act that ADEQ needed to promulgate emission inventory reporting regulations within two years. 42 U.S.C. § 182(a)(3)(B). ADEQ will submit the amended rule to EPA as a revision to the existing Arizona state implementation plan (SIP). 26 Ariz. Admin. Reg. at 3093.

The rulemaking amends Ariz. Admin. Code § 18-2-327 to mandate specific forms of emission reports required under the Clean Air Act. The amendments require regulated sources to submit either an emissions statement or an emissions inventory questionnaire. Stationary sources in nonattainment areas with "actual emissions of 25 tons or more of [NOx] or [VOCs] during the calendar year" must submit an emissions statement to ADEQ on or before June 1 of the following year. *Id.* § 18-2-327(B)(1). Sources that submit an emissions inventory questionnaire, discussed further below, do not need to submit an emissions statement for that year. *Id.* § 18-2-327(B)(5). The emissions statement is specific to the previous calendar year and must include the source's contact information, the source's process and design information (including any emission control devices), the actual emissions of NOx and VOCs, and a certification statement from the responsible official that, "based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." *Id.* § 18-2-327(B)(2). If either NOx or VOC emissions at the regulated source surpass the reporting threshold of 25 tons, but the other pollutant does not, the other pollutant will still need to be included in the emissions statement. *Id.* § 18-2-327(B)(3). Emissions statements later discovered to be incorrect or insufficient may be amended within 30 days of discovery or notice of the error, and operators will not be subject to an enforcement action if the error was not due to willful neglect. *Id.* § 18-2-327(A)(4).

Sources that require a Class I permit must complete and submit an emissions inventory questionnaire to ADEQ no later than June 1 of each year. *Id.* § 18-2-327(A)(1)(a). A Class I permit is required for the construction or operation of any major source, select solid waste incinerators, affected sources, or certain stationary sources designated by EPA. *Id.* § 18-2-302(B). Sources requiring a Class II permit need to submit an emissions inventory questionnaire no later than June 1 every three years beginning June 1, 2021. *Id.* § 18-2-327(A)(1)(b)(i). A Class II permit is required for the construction or operation of a stationary source that emits or has the capacity to emit a regulated new source review (NSR) pollutant in an amount greater than or equal to the significant level, an operational change to a stationary source that would cause the source to emit any regulated NSR pollutant in an amount greater than or equal to the significant level, or the construction or modification of a stationary source that would be subject to registration with ADEQ based on a determination that it may interfere with attainment or the maintenance of a national ambient air quality standard. *Id.* § 18-2-302(B). At ADEQ's request, sources that require a Class II permit may be obligated to submit an emissions inventory questionnaire on an annual basis. *Id.* § 18-2-327(A)(1)(b)(ii). The amended rule does not outline a rationale for why ADEQ may also impose a yearly reporting obligation on Class II sources. The amended rule also outlines a process for amending an emissions inventory questionnaire that is later discovered to be incorrect or insufficient. *Id.* § 18-2-327(A)(4). As with errors in emissions statements, operators will not be subject to an enforcement action if the error in the emissions inventory questionnaire was not the result of willful neglect. *Id.*

ARKANSAS – OIL & GAS

Thomas A. Daily
– Reporter –

Arkansas Supreme Court Affirms Power of Oil and Gas Commission to Limit Royalty Payable to Lessors of Non-Consenting Owner During Payout

Arkansas's compulsory process is called "integration." Issued by the Arkansas Oil and Gas Commission (AOGC), an integration order extends several options to each uncommitted owner who is integrated. Unleased owners may elect to participate in the subject well or, alternatively, may choose among various lease terms. As a final option, an unleased owner may elect to be treated as a non-consenting owner, receiving a 1/8 royalty pending recovery of drilling and completion costs multiplied by a risk factor penalty.

Non-consenting leasehold working interest owners must choose between only the participation and non-consent options. Royalty owners subject to the leases owned by non-consenting working interest owners are normally then paid royalty in accordance with their lease terms by the parties who participate with the non-consenting interest.

Hurd v. Arkansas Oil & Gas Commission, 2020 Ark. 210, 601 S.W.3d 100, was a judicial review of such an integration order. That order was applicable to the appellants, members of the Killam and Hurd families who owned fee mineral interests within a unit previously established by AOGC rule. In its order of integration, which treated them as unleased mineral owners, the AOGC extended the following options:

(1) lease their interests for a $100 per net acre bonus and a 1/8 royalty;

(2) lease their interests for no bonus and a 1/7 royalty;

(3) participate as working interest owners in the drilling of the deeper wells; or

(4) be carried as a non-consent owner and be paid a 1/8 royalty pending recovery of 400% of drilling and completion costs (that royalty would convert to a working interest if and when the 400% payout occurred).

Dissatisfied with the above options, the Hurd and Killam family members instead executed leases to family-owned entities, Hurd Enterprises and Killam Oil Co., causing those entities to become working interest owners. Each such lease provided for a 1/4 royalty. The two family companies then elected the non-consent option, and contended that the participants in the proposed wells would be obligated to pay their family member/lessors the 1/4 royalty. The AOGC then issued an amended integration order reducing the percentage that the non-consenting family companies' related lessors could recover from the participants to 1/7, which was the maximum royalty contained within the AOGC's earlier order.

The Hurd and Killam family members and their companies appealed that amended order, contending that the AOGC was without authority to disregard the royalty provisions of their private lease contracts. The case ultimately reached the Arkansas Supreme Court, which affirmed the AOGC's order. The majority's opinion relied upon a statutory provision, Ark. Code Ann. § 15-72-304(a), requiring integration orders to "be upon terms and conditions that are just and reasonable," thus holding that the AOGC did not abuse its discretion when it determined that the 1/4 royalty in the leases to family-owned entities was unreasonable under the circumstances.

Federal District Court Interprets 1982 JOA Provision Defining "Subsequently Created Interests"

Arkansas Oil and Gas Commission (AOGC) integration orders require parties who elect to participate under the order to be bound by the terms of an operating agreement approved by the AOGC rather than to simply participate as a cotenant. That approved agreement is a modified AAPL Form 610-1982 Model Form Operating Agreement. Mostly as a consequence of the AOGC's approval of that form, it has become the joint operating agreement (JOA) form most commonly used in Arkansas. *Shale Royalty, LLC v. MMGJ Arkansas, LLC*, No. 4:18-cv-00621, 2020 WL 4228580 (E.D. Ark. July 23, 2020), is a case pending in the U.S. District Court for the Eastern District of Arkansas. It involves a legal question that is apparently unique to operations governed by the 1982 form. Article III.D of that form of agreement treats overriding royalty interests burdening a party as "subsequently created interests," which are the sole obligation of that party and are not transferred to the participating parties when the burdened party declines to participate in an operation pursuant to article VI.B.2.b of that form. Such a provision is common to other modern AAPL Form 610 agreements but, unlike the 1989 and 2015 forms, the 1982 form contains an exception to "subsequently created interests" for a burden that was "disclosed in writing to all other parties prior to the execution of this agreement by all parties."

Shale Royalty, LLC's (Shale Royalty) predecessor-in-interest had assigned leasehold interests to MMGJ Arkansas, LLC's (MMGJ) predecessor, reserving overriding royalties. It assigned those overriding interests to Shale Royalty. Both assignments preceded the operating agreement's execution as did their recordation in the county's real property records. When MMGJ became a non-consenting party under the JOA's article VI.B.2.b, Shale Royalty contended that the participating parties became obligated to pay its overriding royalties. The legal question presented is whether the prior recording of the assignments satisfied the requirement of the "disclosed in writing to all parties" exception to the definition of subsequently created interests.

In a July 23, 2020, summary judgment order, the district court held that the written disclosure required by article III.D was more than the mere constructive notice accomplished by recordation. Rather, the court opined that "the methods for disclosing existing burdens under Article III.D are designed to provide clear communication regarding existing burdens. Imputed or constructive notice will not do." 2020 WL 4228580, at *5. Thus, Shale Royalty must look only to its assignees for payment of its overriding royalties, notwithstanding their non-consent status.

Since the court's order was not dispositive of all claims in the case, it is not yet appealable.

Oil and Gas Commission Order Prohibits Production of "Below-Cost" Oil

In response to a precipitous decline in crude oil prices during the COVID-19 pandemic, the Arkansas Oil and Gas Commission (AOGC) issued Emergency Order No. 024A-2-2020-05, made permanent by Order No. 058-2-2020-06, prohibiting the producing for sale of oil from any well that can reasonably be marketed only as "below-cost production," subject to certain exceptions contained therein. Below-cost production is defined in the order as production sold at a price less than "production costs," defined as allowable direct costs under the COPAS attachment to the AOGC-approved operating agreement plus 10% of the posted price of Arkansas's only oil refinery, Lion Oil Trading and Transportation.

CALIFORNIA – OIL & GAS

Tracy K. Hunckler
– Reporter –

Update: Ventura County's New Restrictions for Historical Permits for Oil and Gas Activities Are Stayed Pending Vote of General Public in June 2022

As previously reported in Vol. XXXVII, No. 3 (2020) and Vol. XXXVII, No. 4 (2020) of this *Newsletter*, on November 10, 2020, by a 3 to 2 vote, the Ventura County Board of Supervisors (Board) adopted amendments to Ventura County's (County) zoning ordinance regulating oil and gas activities under County permits issued prior to the 1960s. As discussed in the prior reports, the amendments would affect these historical permits by:

(1) requiring discretionary approval of a new conditional use permit or a discretionary permit adjustment for

new oil and gas development regardless of the age of the underlying permit;

(2) requiring environmental review of the proposed new development, even though the underlying permit may not have been subject to environmental review; and

(3) requiring that all new development must meet the County's general permit approval standards.

The County's broader authority to regulate historical oil and gas permits under these amendments has been challenged in lawsuits filed by permit holders who have vested and constitutionally protected rights to operate under their existing permits. The lawsuits are in the early stages of litigation at this point, with no responsive pleadings being filed by the County.

In addition to the legal challenges, on December 10, 2020, timely referendum petitions against the amendments were submitted to the County with the required signatures of the voters, as later certified by the County's Elections Division. A discussion of the referendum petitions, signatures, and certification process can be found at http://bosagenda.countyofventura.org/sirepub/cache/2/n0rlokclwiuz5ogehumi5bhg/167846002112021033924749.pdf. Upon presentation of the petitions, the enforceability of the amendments was suspended.

> Pursuant to [California] Elections Code section 9145, upon the[] certifications [of the signatures], [the] Board must do one of the following: 1) repeal in their entirety the ordinances against which the petitions are filed; or 2) submit the ordinances to the voters, either at the next regularly scheduled county election occurring not less than 88 days after the date of the order, which would occur on June 7, 2022, or at a special election called for that purpose not less than 88 days after the date of the order.

Id. At its February 2, 2021, meeting, the Board voted unanimously to submit the amendments to the voters as part of the June 7, 2022, general election. Accordingly, the amendments will have no effect unless and until a majority of the voters decide to approve them as part of that election.

Gas Pipeline Company Required to Move Pipelines at Its Own Expense So That Modern Commuter Rail Train Could Be Extended

In *Riverside County Transportation Commission v. Southern California Gas Co.*, 268 Cal. Rptr. 3d 196 (Ct. App. 2020), the California Court of Appeal analyzed whether the Riverside County Transportation Commission (Commission) could require Southern California Gas Company (Gas Company) to relocate pipelines it had installed under public streets pursuant to decades-old franchises from the relevant cities and, in all but one instance, pursuant to licenses from the prior owner of preexisting rail lines. The Commission, which now owned the preexisting rail lines, desired to extend a modern commuter rail train in the same location as the preexisting lines, but it could not do so without removal of the Gas Company's pipelines. So that its expansion project could move forward, the Commission terminated the Gas Company's licenses and demanded the removal of the pipelines at the Gas Company's expense.

As framed by the court of appeal, the case presented familiar questions that have been raised since the 1800s: "When the time comes to install or to improve . . . modern conveniences, what is to be done about another one that stands in its way? Can one force the other to relocate? And if so, who must pay for the relocation?" *Id.* at 202. As aptly noted by the court, these cases share a common theme: "You can't stand in the way of progress." *Id.* Consistent with that theme, the court of appeal affirmed the trial court's ruling that the Gas Company had to bear all costs of relocating the pipelines.

The court of appeal disagreed with the trial court's other ruling that there was no trespass after the Commission had terminated the licenses and the pipelines had not been removed. Instead, the court held "that, at those points where the Gas Company held licenses for its pipelines, once the Commission terminated the licenses, the Gas Company could be held liable for trespass." *Id.* at 202–03. The court of appeal reversed the grant of summary adjudication as to that issue only.

COLORADO – MINING

Kristin A. Nichols
– Reporter –

Colorado Regulators Announce Upcoming Revisions to Hardrock Mining Regulations

The Colorado Department of Natural Resources' Division of Reclamation, Mining and Safety (DRMS) has initiated formal rulemaking to revise its hardrock mining regulations. According to DRMS, the revisions are necessary "to address the requirements of HB19-1113 for perpetual water treatment, certain annual water quality reporting and the elimination of self-bonding." DRMS, "Notice of Intent to Initiate Hard Rock Rulemaking" (Dec. 11, 2020). Additionally, DRMS is revising its regulations related to temporary cessation "to address inconsistencies and ambiguities and create a clearer administrative process for regulation of [temporary cessation]." *Id.*

DRMS held stakeholder meetings in January 2021 to discuss the proposed rules, address issues with the proposed revisions, and identify potential alternatives. The deadline for comments was February 18, 2021. DRMS will now revise the proposed regulations and release a final redline in April 2021. In May and June 2021, DRMS will hold additional stakeholder meetings. The final regulations will be adopted in June or July 2021. The current timeline of the rulemaking is tentative and subject to change. Information related to this rulemaking, including a redline version of the proposed rules and the most up-to-date schedule, can be viewed at https://www.colorado.gov/pacific/drms/2021-hard-rock-rulemaking.

COLORADO – OIL & GAS

Sarah Sorum
Kate Mailliard
– Reporters –

Year-End Legal Actions in Boulder County

Lafayette extended its ban on new oil and gas drilling through May 2021 after the city council voted unanimously in November 2020 to extend the existing moratorium. *See* City of Lafayette, "Oil and Gas Information and Resources," https://www.lafayetteco.gov/oilandgas. The city originally approved a moratorium on the submission, acceptance, processing, and approval of land use applications related to the exploration and extraction of oil and gas in November 2017. The original moratorium had been extended through November 2020, *see* Vol. XXXVII, No. 2 (2020) of this *Newsletter*, but is now in place for an additional six months.

At the end of 2020, Boulder County District Judge Judith L. LaBuda dismissed an argument that a fracking ban approved by Longmont voters in 2012 is now enforceable under Senate Bill 19-181 (SB 19-181). *See Our Health, Our Future, Our Longmont v. State*, No. 2020CV3033 (Colo. Dist. Ct., Boulder Cty., Nov. 1, 2020) (Order Re: Plaintiffs' Motion for Summary Judgment and Defendant-Intervenor's Cross-Motion for Summary Judgment). The district court relied in part on the Colorado Supreme Court's ruling in *City of Longmont v. Colorado Oil & Gas Ass'n*, 2016 CO 29, 369 P.3d 573, in which the court found that Longmont's ban on fracking was unconstitutional. *See* Vol. XXXIII, No. 2 (2016) of this *Newsletter*. Under *City of Longmont*, the State's interest in uniformly regulating the energy industry preempts the interests of the local government. 2016 CO 29, ¶ 54. Judge LaBuda ruled that, while SB 19-181 "changed the law affecting local government's power to regulate land use," *Our Health*, slip op. at 3, the fracking ban continued to be in conflict with state law and was thus preempted, *id.* at 12.

New COGCC Rule Restricts Venting and Flaring

On November 23, 2020, the Colorado Oil and Gas Conservation Commission (COGCC) completed its "mission change" rulemaking hearings mandated by Senate Bill 19-181, including the 900 Series rules titled "Environmental Impact Prevention." *See* Press Release, COGCC, "Colorado Oil & Gas Conservation Commission Unanimously Adopts SB 19-181 New Mission Change Rules, Alternative Location Analysis and Cumulative Impacts" (Nov. 23, 2020). The 900 Series rules took effect January 15, 2021. Under the new venting and flaring rules, venting or flaring after commencement of production is permitted only during "upset conditions" at the wellhead, during active and required maintenance and repair activity at the wellhead, during a Bradenhead test, as part of an approved gas capture plan, or during emergencies as specified under COGCC rules. 2 Colo. Code Regs. § 404-1:903.d.(1); *see* COGCC, "Mission Change Rulemaking Series Fact Sheet" (Nov. 23, 2020). All venting and flaring exceptions are subject to strict specifications, require notice, and, in certain cases, require written authorization from the COGCC. During drilling and completion operations, venting or flaring is permitted in certain circumstances subject to time limitations, notice and approval requirements, and other specifications. 2 Colo. Code Regs. § 404-1:903.b., c. Companies currently venting or flaring pursuant to approval received prior to January 15, 2021, may continue only by requesting permission via a Form 4 before the date the prior-approved Form 4 expires (and in no case later than January 15, 2022). *Id.* § 404-1:903.d.(3). The operator may apply for this one-time request to vent or flare for a period not to exceed 12 months, and venting or flaring will not be approved to any date after January 15, 2022. *Id.*

MICHIGAN – MINING

Dennis J. Donohue
– Reporter –

Dredge and Fill Permit for Back Forty Mine Denied; Appeal Pending

On January 4, 2021, a Michigan administrative law judge (ALJ) denied a wetlands dredge and fill permit for Aquila Resources Inc.'s (Aquila) Back Forty Mine project previously issued by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) in June 2018. The ALJ concluded that Aquila's permit application was not "administratively complete" because Aquila's estimates of the indirect wetland impacts that could potentially occur due to drawdown of groundwater near the proposed open pit mine were not precise or reliable enough to facilitate substantive review of the permit application. Thus, the permit should not have been issued, despite that fact that the U.S. Environmental Protection Agency (EPA) had previously withdrawn its objections to issuing the permit. (Michigan is one of two states with delegated authority for the Clean Water Act § 404 wetlands permit program, although EPA retains authority to review and comment on wetland permit applications submitted to EGLE.)

Aquila claims that its groundwater modeling and estimates for potential indirect impacts went beyond what the U.S. Army Corps of Engineers requires in other mining projects. Accordingly, on January 25, 2021, Aquila appealed the ALJ's decision to the EGLE environmental review panel. EGLE will convene a three-person panel of technical experts with relevant experience within 45 days. The panel will then hear arguments and is expected to render a decision later in 2021. The panel has the authority to adopt, remand, modify, or reverse, in whole or in part, the ALJ's decision. The decision of the panel will become the final decision of EGLE.

Editor's Note: The reporter represents Aquila and the Back Forty Mine project.

OHIO – MINING / OIL & GAS

J. Richard Emens
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– Reporters –

Marketable Title Act and Dormant Mineral Act May Both Be Used to Terminate Severances of Oil and Gas

The Ohio Marketable Title Act (MTA), Ohio Rev. Code §§ 5301.47–.55, was enacted in 1961 and "provides that a person who has an unbroken chain of title of record to any interest in land for at least 40 years has a 'marketable record title' to the interest." *West v. Bode*, 2020-Ohio-5473, ¶ 15 (quoting Ohio Rev. Code § 5301.48). The Ohio Dormant Mineral Act (DMA), Ohio Rev. Code § 5301.56, was enacted in 1989 "to provide a method for the termination of dormant mineral interests and the vesting of their title in surface owners, in the absence of certain occurrences within the preceding 20 years." *Bode*, 2020-Ohio-5473, ¶ 21 (quoting *Corban v. Chesapeake Exploration, LLC*, 2016-Ohio-5796, ¶ 19, 76 N.E.3d 1089). Questions had arisen in Ohio whether the MTA could be used to terminate severances of oil and gas after the enactment of the DMA. *See generally id.* In *Bode* the Supreme Court of Ohio affirmed the Seventh District Court of Appeals by holding the MTA and the DMA are not in irreconcilable conflict and a landowner may utilize both statutes in attempting to terminate historical severances of oil and gas.

Bode involved a 1902 sale of one-half of the royalty interest underlying a property in Monroe County, Ohio, to C.J. Bode and George T. Nalley. *Id.* ¶ 4. The surface of the property and the other half of the oil and gas royalty was conveyed to Wayne West and Rusty West after successive conveyances, "subject to all . . . reservations of record." *Id.* ¶ 5. In February 2017, the Wests filed a lawsuit against the heirs of Bode and Nalley claiming that the severed one-half oil and gas royalty was extinguished pursuant to the MTA. *Id.* ¶ 6. John L. Christman, Katherine Haselberger, and Charlotte McCoy intervened in the lawsuit, claiming to be the successors-in-interest to Nova A.

Christman, who was conveyed a 1/16 interest in the oil and gas royalty pursuant to a 1944 auditor's deed. *Id.* ¶ 7.

The parties filed competing motions for summary judgment. *Id.* ¶ 8. The trial court entered summary judgment in favor of Christman's successors-in-interest claiming that the more-specific provisions of the DMA were in irreconcilable conflict with the more-general MTA and, thus, the later-enacted DMA controlled to the exclusion of the MTA. *Id.* ¶ 9. The Seventh District reversed the trial court and held that the MTA and the DMA "are co-extensive alternatives whose applicability in a particular case depends on the time passed and the nature of the items existing in the pertinent records." *Id.* ¶ 10 (quoting *West v. Bode*, 2019-Ohio-4092, ¶ 47, 145 N.E.3d 1190); *see* Vol. XXXVI, No. 4 (2019) of this *Newsletter*.

The supreme court reviewed Ohio Rev. Code § 1.51, which states:

> If a general provision conflicts with a special or local provision, they shall be construed, if possible, so that effect is given to both. If the conflict between the provisions is irreconcilable, the special or local provision prevails as an exception to the general provision, unless the general provision is the later adoption and the manifest intent is that the general provision prevail.

Bode, 2020-Ohio-5473, ¶ 12. The supreme court noted that while the MTA and DMA are different statutory mechanisms,

> [t]here is nothing in the statutory language of either act to preclude a mineral-interest holder from ensuring compliance with both the [MTA] and the [DMA]. Each statute sets out simple actions that a holder of a mineral interest may take to perpetually preserve that interest. The differences between the acts do not create any obstacle to giving effect to both, which is what R.C. 1.51 directs us to do.

Id. ¶ 32. Thus, the supreme court held that the MTA and the DMA are not in irreconcilable conflict and both statutes may be used to terminate severances of oil and gas. *Id.* ¶ 44.

The supreme court's decision in *Bode* is significant. The decision makes it clear that the owners of property in Ohio have multiple avenues to clear title to oil and gas under their properties. Historically, the ownership of oil and gas minerals has been the subject of numerous lawsuits, which may now be decided pursuant to the MTA. Clearing the titles to oil and gas should reduce the frequency in which oil and gas companies take oil and gas leases from multiple claimants or hold oil and gas royalties in suspense due to unclear titles.

Dormant Mineral Act Requires "Reasonable Diligence" to Locate Holders of Severed Oil and Gas Interests to Serve by Certified Mail Prior to Providing Notice by Publication

The Ohio Dormant Mineral Act (DMA), Ohio Rev. Code § 5301.56,

> provides that unless a severed mineral interest is in coal or is coal related, the interest is held by the United States, the state or any other political body described in the statute, or a saving event enumerated in R.C. 5301.56(B)(3) has occurred within the preceding 20 years, the mineral interest "shall be deemed abandoned and vested in the owner of the surface of the lands" if the surface owner has satisfied the requirements of R.C. 5301.56(E).

Gerrity v. Chervenak, 2020-Ohio-6705, ¶ 9 (quoting Ohio Rev. Code § 5301.56(B)). Since the dawn of the Utica Shale play, numerous surface owners have attempted to use the DMA to have severed oil and gas deemed abandoned and vested in the owner of the surface. One of the requirements in the DMA is that surface owners

> [s]erve notice by certified mail, return receipt requested, to each holder or each holder's successors or assignees, at the last known address of each, of the owner's intent to declare the mineral interest abandoned. If service of notice cannot be completed to any holder, the owner shall publish notice of the owner's intent to declare the mineral interest abandoned at least once in a newspaper of general circulation in each county in which the land that is subject to the interest is located. The notice shall contain all of the information specified in division (F) of this section.

Id. (quoting Ohio Rev. Code § 5301.56(E)(1)). After failing to locate all holders, it was common for surface owners to resort to publication. This led to a myriad of lawsuits by holders claiming that surface owners did not comply with the DMA due to failure to properly locate and notify the holders. The Supreme Court of Ohio took up issues related to the notice requirements in the DMA in *Gerrity v. Chervenak*.

In *Gerrity*, the supreme court affirmed a decision by the Fifth District Court of Appeals, *see* Vol. XXXVI, No. 3 (2019) of this *Newsletter*, and unanimously held that a surface owner need only exercise "reasonable diligence" in attempting to locate potential holders of a severed oil and gas mineral interest prior to resorting to notice by publication. *Gerrity* involved a 1961 reservation of oil and gas made by T.D. Farwell underlying property in Guernsey County, Ohio, now owned by the Chervenak Family Trust. *Gerrity*, 2020-Ohio-6705, ¶ 2. In 2012, a title search related to the property identified Jane F. Richards, the daughter of Farwell, as the owner of the oil and gas interest severed in 1961 based upon a certificate of transfer recorded in October 1965 in Guernsey County. *Id.* ¶ 3. The certificate of transfer listed a Cuyahoga County, Ohio, address for Richards. *Id.* There were no other records in Guernsey County regarding ownership of the severed oil and gas interest. *Id.* Based on the Cuyahoga County address in the 1965 certificate of transfer a search of the Cuyahoga County records was conducted to search for an estate for Richards or a more recent address but such records gave no indication that Richards had died or transferred the mineral interest. *Id.* ¶ 32.

Therefore, the Chervenaks attempted to serve Richards notice by certified mail at her last known address in the 1965 certificate of transfer. *Id.* ¶ 5. When that could not be completed the Chervenaks published notice in May 2012. *Id.* After the Chervenaks filed an affidavit of abandonment in Guernsey County, the recorder made a marginal notation on the severance deed that the severance of oil and gas had been deemed abandoned. *Id.*

In 2017, Gerrity, the only heir of Richards, filed a quiet title action claiming that the Chervenaks failed to comply with the notice requirements of the DMA. *Id.* ¶ 6. Richards died in 1997, a resident of Florida, and Gerrity claimed rights in the mineral interest based on the probate of Richards's estate in Florida. *Id.* ¶ 4. However, the Guernsey County records "contain no evidence of Richards's death or of Gerrity's inheritance of the mineral interest." *Id.* Gerrity argued that the DMA requires strict compliance, such that a surface owner must identify every holder of a mineral interest and attempt service on them by certified mail. *Id.* ¶ 12. The supreme court rejected this argument based on a reading of the DMA as a whole and the codified legislative intent of the general assembly. *Id.* ¶ 13. The court found that the DMA expressly acknowledges situations where service of notice cannot be completed by certified mail and permits publication in those situations, and clearly, when a holder is unidentifiable or unlocatable, the DMA permits service of notice by publication. *Id.* ¶ 17.

Despite requests from both sides, the supreme court refused to adopt a bright-line rule specifically defining the steps the DMA requires a surface owner to take to identify and locate holders of a severed mineral interest. *Id.* ¶ 31. Gerrity contended that the DMA requires "a surface owner to search not only public records but also online resources, including subscription-based genealogy services, and to document those efforts." *Id.* Conversely, the Chervenaks argued that the DMA only requires a search of the surface owner's chain of title to identify mineral holders. *Id.* However, the supreme court followed the lead of the Seventh District Court of Appeals and held that a surface owner must exercise "reasonable diligence" in locating holders, and "whether a party has exercised reasonable diligence will depend on the facts and circumstances of each case." *Id.* (citing *Sharp v. Miller*, 2018-Ohio-4740, 114 N.E.3d 1285 (7th Dist.)).

The supreme court did hold that the "[r]eview of public-property and court records in the county where the land subject to a severed mineral interest is located will generally establish a baseline of reasonable diligence in identifying the holder or holders of the severed mineral interest." *Id.* ¶ 36. However, it went on to acknowledge that "[t]here may, however, be circumstances in which the surface owner's independent knowledge or information revealed by the surface owner's review of the public-property and court records would require the surface owner, in the exercise of reasonable diligence, to continue looking elsewhere to identify or locate a holder." *Id.* Based on the facts at issue the court found that reasonable diligence had been exercised by the Chervenaks based on their diligent search of the public records in both Guernsey County where the property was located and Cuyahoga County and the fact that such records "revealed no indication that the sole record holder was deceased and offered no clue as to the identity of any potential successors or assigns." *Id.* The court rejected Gerrity's claim that the Chervenaks should have conducted an Internet search where the record contained no specific evidence of what an Internet search would have revealed in 2012 and in light of "[t]he ever-changing quantum and quality of information available in the Internet, the inconsistent reliability of that information, and the variability of Internet-search results." *Id.* ¶ 34.

The supreme court's decision in *Gerrity* provides some relief to surface owners, although significant questions remain about how it will be interpreted when different facts are at issue. The facts in the *Gerrity* case were extremely favorable to the surface owner, who searched not only the records of the county where the property was located but also records outside of that county, attempted service by certified mail on the 1965 address revealed in the records of the county where the property was located prior to providing notice by publication, and had no information based on the county records that the record holder died or of the identity of any other potential holders. It remains to be seen whether "reasonable diligence" will be deemed to have been exercised in situations where a surface owner searches the records of the county where the property was located and establishes a baseline of reasonable diligence, but may have not have taken the other steps the surface owner took in *Gerrity*. Based on the language in *Gerrity* relating to establishing a baseline of reasonable diligence, it appears the supreme court may place the burden on the surface owner to establish that the records of the county where the property was located were searched prior to publication, but require the mineral holder to show additional actions were required to exercise "reasonable diligence" if that baseline of reasonable diligence has been established.

The decision not to adopt a bright-line rule means there will continue to be a lot of litigation over the notice requirements in the DMA and continued uncertainty about who owns oil and gas mineral rights in situations that involve notice issues. This means the oil and gas industry will likely continue to hold funds in suspense when such issues arise and require the parties to litigate the issues. Despite this uncertainty, and the failure to adopt a bright-line rule favorable to surface owners, this decision is still a victory for surface owners because adoption of the strict compliance standard Gerrity argued for would likely have effectively prevented use of the DMA by surface owners, and the supreme court made clear that neither attempted service by certified mail nor an Internet search is required prior to publishing notice. These are often the biggest, or only, issues mineral holders raise when claiming surface owners have failed to meet the notice requirements in the DMA.

PENNSYLVANIA – MINING

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– Reporters –

Significant Public Participation Regarding PADEP's RGGI Rule

Pennsylvania's Environmental Quality Board (EQB) published its proposed Regional Greenhouse Gas Initiative (RGGI) CO_2 Budget Trading Program rule in the *Pennsylvania Bulletin* on November 7, 2020, which opened the public comment period for the rule. *See* 50 Pa. Bull. 6212 (Nov. 7, 2020). EQB hosted a number of virtual public hearings in December 2020 and accepted comment until January 14, 2021. EQB received more than 13,000 public comments on the proposed rule. Currently, the Independent Regulatory Review Commission (IRRC) is reviewing the proposed CO_2 Budget Trading Program rule. The IRRC reviews regulations under the Regulatory Review Act to determine whether a proposed regulation is consistent with the authorizing statute and whether the regulation is in the public interest. While the IRRC has access to all public comments submitted to EQB regarding the proposed CO_2 Budget Trading Program rule, the IRRC has also received a significant number of comments directly from legislators and the public. The IRRC's comments, recommendations, or objections on the proposed regulation were due to the Pennsylvania Department of Environmental Protection by February 16, 2021.

A final regulation is expected later in 2021, at which time EQB will also release its responses to the public comments submitted on the proposed rule. The rule is tentatively scheduled to take effect in January 2022. For detailed descriptions of the content and implementation of the proposed rule, see 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*.

Ozone Transport Commission Recommends Daily NOx Emission Limits at Coal-Fired Power Plants in Pennsylvania

On June 8, 2020, the U.S. Environmental Protection Agency (EPA) received a recommendation from the Ozone Transport

Commission (OTC) that EPA require Pennsylvania to adopt daily limits on nitrogen oxide (NO_X) emissions from coal-fired electric generating units (EGUs). *See* 85 Fed. Reg. 41,972 (July 13, 2020). The OTC oversees the administration of the Ozone Transport Region (OTR), which includes Connecticut, Delaware, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, the District of Columbia, and parts of Virginia. The OTC and OTR were established as part of the 1990 amendments to the Clean Air Act (CAA) due to recognition that the transport of ozone and ozone precursors throughout the northeastern states may render the states' attainment strategies interdependent.

The recommendation was submitted under section 184(c) of the CAA, which allows the OTC to develop, and submit to EPA, recommendations for additional control measures to be applied within all or a part of the OTR if such measures are necessary to bring any area in the OTR into attainment with national ambient air quality standards (NAAQS) for ozone by the applicable attainment deadlines. 42 U.S.C. § 7511c(c). Upon receipt, EPA must publish a notice in the *Federal Register*, hold a public hearing within 90 days of receipt, and make a determination within nine months approving or disapproving the recommendation. *Id.* If EPA determines that the measures in the recommendation are necessary to bring any area in the OTR into attainment, EPA will make a finding under CAA § 110(k)(5) that the state implementation plan (SIP) for that state is inadequate to meet the requirements of CAA § 110(a)(2)(D), often referred to as the "good neighbor provision." *Id.* § 7410. EPA then requires each affected state to revise its SIP to include the approved additional control measures. *Id.* § 7511c(c)(5).

The OTC's recommendation, dated June 5, 2020, suggests that EPA require Pennsylvania to adopt daily limits on NO_X emissions from coal-fired EGUs with existing selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) controls. The OTC recommends that these limits be at least as stringent as those in place for plants in Delaware, Maryland, and New Jersey to ensure that controls are optimized throughout the ozone season to help downwind states attain the ozone standard by the dates required in the CAA. The OTC provided its four main reasons for making this recommendation under CAA § 184(c): (1) several areas in the OTR are not expected to attain the 2015 ozone NAAQS by 2021; (2) research shows that large regional NO_X reductions lower peak ozone across the eastern United States and that additional NO_X reductions are needed for attainment of the 2008 and 2015 ozone NAAQS; (3) the OTC references EPA information identifying emissions from Pennsylvania as contributing to downwind nonattainment and includes estimates developed by Maryland of additional NO_X reductions from Pennsylvania EGUs that could be achieved through daily NO_X limits; and (4) the OTC decided to use the CAA § 184(c) process after a collaborative process resulted in some states adopting daily NO_X limits, while Pennsylvania has not.

EPA issued a *Federal Register* notice on July 13, 2020, that the OTC had submitted a recommendation, *see* 85 Fed. Reg. 41,972 (July 13, 2020), but delayed the public hearing, originally scheduled for September 4, 2020. On January 15, 2021, EPA issued a notice in the *Federal Register* announcing a virtual public hearing on February 2, 2021, and opening a public comment period. *See* 86 Fed. Reg. 4049 (Jan. 15, 2021). This notice also summarizes the OTC's recommendations, provides additional information EPA believes will be relevant in reaching a decision, and requests input on various issues. Specifically, EPA requested comment regarding whether the Delaware, Maryland, and New Jersey regulations have been accurately summarized, how those regulations could be used as standards for evaluating a SIP revision submitted by Pennsylvania, and EPA's authority under CAA § 184(c) to modify the OTC's recommendation. EPA recently extended the public comment period on these issues until April 7, 2021. *See* 86 Fed. Reg. 10,267 (Feb. 19, 2021).

PADEP Publishes Draft Reissuance of General Permit for Stormwater Discharges Associated with Mining Activities

On January 9, 2021, the Pennsylvania Department of Environmental Protection (PADEP) published notification of its intent to modify and reissue the National Pollutant Discharge Elimination System (NPDES) General Permit for Stormwater Associated with Mining Activities (GP-104). *See* 51 Pa. Bull. 241 (Jan. 9, 2021). The five-year term of the current GP-104 was set to expire on February 12, 2021, but was extended until the permit is reissued. According to PADEP, the revised GP-104 includes "extensive revisions" required by the U.S. Environmental Protection Agency (EPA) that will affect coal and non-coal mining operators. Notable proposed modifications to GP-104 include the following:

- *Expiration of Permit Coverage*. The current GP-104 provides authorization for five years from the date the operator obtains coverage. Under the revised GP-104, authorization would expire upon expiration of the general permit. In other words, an operator that obtains coverage in the middle of the permit term would only be authorized to discharge for the remainder of the term rather than a full five years. The *Pennsylvania Bulletin* notice states that operators with current GP-104 authorizations that expire after February 2021 will receive notice and the option to certify acceptance of the renewed GP-104 with no reapplication or fee required.
- *Applicability*. The revised GP-104 would clarify that activities authorized through a government-financed construction contract with PADEP would be eligible for coverage under the general permit. In contrast, the revised GP-104 would not authorize discharges to sediment-impaired waters or discharges that may result in discharges of toxic substances at levels that exceed applicable water quality criteria. The revised permit also clarifies that it does not apply to activities that may result in a discharge from underground mines, acid mine drainage, pumped groundwater, water used to refine or wash product, or stormwater that is commingled with such sources. *See* PADEP, Draft Approval of Coverage Under the General NPDES Permit for Stormwater Discharges Associated with Mining Activities, § 2(d) (rev. Jan. 2021). Operators ineligible for coverage under GP-104 would be required to obtain an individual NPDES permit.
- *Effluent Limitations*. GP-104 includes effluent limitations for pH, total suspended solids, and total settleable solids in part A of the permit. The current GP-104 includes instantaneous maximum, daily maximum, and 30-day average limits. The proposed GP-104 would eliminate the daily maximum and 30-day average limits and only require instantaneous maximum limits. The revised GP-104 would also include a new provision stating that the discharge must meet applicable total maximum daily loads and must not cause or contribute to an exceedance of applicable water quality standards. This provision would further enable PADEP to revoke the general permit at any time "if the status

of a watershed or receiving stream changes," in which case the operator would be required to apply for an individual permit. *Id.* § A(1)(c).

The proposed GP-104 would also make several revisions to the standard conditions in part B of the permit, including monitoring, recordkeeping, and reporting; modification or termination; civil and criminal penalties under the Clean Water Act; and certification requirements. The 30-day public comment period on the draft permit closed on February 8, 2021.

PADEP Invites Public Comments on Act 54 Report Regarding Effects of Mine Subsidence

On January 9, 2021, the Citizens Advisory Council (CAC) of the Pennsylvania Department of Environmental Protection (PADEP) published notice in the *Pennsylvania Bulletin* of a public comment period on the report entitled "The Effects of Subsidence Resulting from Underground Bituminous Coal Mining in Pennsylvania, 2013–2018" (2019) (Report). *See* 51 Pa. Bull. 241 (Jan. 9, 2021). The Act of June 22, 1994, P.L. 357, No. 54 (Act 54) amended the Bituminous Mine Subsidence and Land Conservation Act of 1966, 52 Pa. Stat. § 1406.18a, to require PADEP to compile data and report findings regarding the effects of underground mining on land, structures, and water resources. An Act 54 report is prepared and presented to the governor, the Pennsylvania General Assembly, and the CAC every five years. The current Report is the fifth report issued since the passage of Act 54. As reported in Vol. XXXVII, No. 1 (2020) of this *Newsletter*, the Report was finalized in 2019. The January 9, 2021, notice provides the opportunity for the regulated community and the public to comment on the final Report. Comments may be submitted through April 9, 2021.

The Report, compiled by the University of Pittsburgh, is approximately 225 pages long and nearly 1,000 pages with attachments. It describes the University's findings regarding the effects of mine subsidence on land, structures, water supplies, hydrologic balance, groundwater, streams, and wetlands, and provides recommendations to PADEP.

- *Land and Structure Damages*. The Report identifies 124 reported impacts to land from underground mine subsidence, 66 of which were classified "Company Liable," defined as a final resolution holding the mining company responsible for the damage. Report at 6-3, 6-18. The Report identifies reported structural effects at 455 of the 3,612 (15%) structures that were undermined from 2013 to 2018, with 247 of the reported effects classified as "Company Liable." *Id.* at 4-2. Most of the identified impacts to land or structures were attributed to longwall mining.
- *Water Supply Impacts*. The Report identifies reported impacts, primarily loss of flow, to 379 of 2,353 (16%) water supplies in undermined areas during the assessment period, with 192 classified as "Company Liable." This is a significant decrease from the 2008–2013 Act 54 Report, which identified 855 water supply impacts. *Id.* at 5-5; *see* Vol. XXXII, No. 1 (2015) of this *Newsletter*.
- *Streams*. The Report identifies approximately 81 miles of streams over 148 stream reaches that were undermined during the assessment period. The Report identifies approximately 52 miles (64%) of streams that were impacted by flow loss, pooling, or both. Overall, impacts were identified in approximately half of the stream reaches that were undermined during the assessment period. Report at 9-5.
- *Hydrologic Balance and Groundwater*. Generally, the Report notes that it is difficult to assess the effects of subsidence on hydrologic balance or groundwater. *Id.* at 7-2, 8-18. Thus, rather than discussing statistics involving specifically identified impacts, the Report discusses how certain data can be better utilized to assess such effects.

The Report concludes with 40 recommendations to PADEP, many of which relate to increasing data collection and usage to better evaluate the impact of mine subsidence on hydrologic balance, groundwater, streams, and wetlands. *See id.* at 12-1 to 12-10.

OSMRE Approves Updates to Pennsylvania Regulatory Program

The federal Office of Surface Mining Reclamation and Enforcement (OSMRE) took two notable actions in its oversight of Pennsylvania's mining program in the past quarter.

<u>Approval of Amendments Regarding Effluent Limitations</u>

On November 9, 2020, OSMRE published notice in the *Federal Register* of the agency's approval of two amendments to Pennsylvania's regulatory program that the Pennsylvania Department of Environmental Protection (PADEP) originally submitted to OSMRE in 2010. *See* 85 Fed. Reg. 71,251 (Nov. 9, 2020).

First, PADEP proposed to delete manganese from the Group B effluent limitation guidelines (ELGs) applicable during precipitation events. PADEP submitted the proposed amendment on its own initiative to bring state regulations current with the U.S. Environmental Protection Agency's (EPA) ELGs applicable to the mining industry at 40 C.F.R. § 434.63. 85 Fed. Reg. at 71,253. OSMRE approved the amendment as consistent with federal requirements. *Id.* at 71,255. Manganese is still included in Group A ELGs, which apply in the absence of a precipitation event.

The second change involves PADEP regulations regarding passive treatment of post-mining pollutional discharges. The changes add definitions of "post-mining pollutional discharges" and "passive treatment" to 25 Pa. Code § 86.1. The amendments then set criteria for treating post-mining pollutional discharges based on levels of pH, acidity, and alkalinity, establish design standards for passive treatment system, and set alternate ELGs for post-mining pollutional discharges treated with passive treatment systems. 85 Fed. Reg. at 71,253–54.

OSMRE noted that federal regulations do not contain provisions that address post-mining pollutional discharges or the use of passive treatment systems. In support of the amendments, PADEP cited a January 28, 1992, memorandum from EPA to Pennsylvania that stated the effluent limitations applicable to the mining industry at 40 C.F.R. pt. 434 do not expressly apply to groundwater seeps and recommended PADEP establish effluent limitations for post-mining pollutional discharges using its best professional judgment (BPJ). Pennsylvania completed its BPJ analysis in 1994. 85 Fed. Reg. at 71,254–55.

In approving the amendments, OSMRE concluded that establishing regulations for the passive treatment of post-mining pollutional discharges is within PADEP's authority under state law and is not inconsistent with federal requirements. However, OSMRE declined to approve the part of the definition of post-mining pollutional discharges that references the definition of "minimal impact post-mining discharges" in Pennsylvania's Surface Mining Conservation and Reclamation Act, 52 Pa. Stat. § 1396.4, because, according to OSMRE, that statutory definition itself was never approved by OSMRE. 85 Fed. Reg. at 71,256–57.

The approximately 10-year delay in OSMRE approving the proposed amendments appears to be due in part to extensive comments from federal agencies and public interest groups on the proposed amendments. The history of the amendments is summarized in the *Federal Register* notice at pages 71,257–62.

Notice of Receipt of Federal Consistency Rulemaking

As reported in Vol. XXXVII, No. 2 (2020) of this *Newsletter*, on March 14, 2020, the Environmental Quality Board (EQB) published the final "Federal Office of Surface Mining Reclamation and Enforcement Program Consistency" rule in the *Pennsylvania Bulletin*. *See* 50 Pa. Bull. 1508 (Mar. 14, 2020). On December 17, 2020, OSMRE published notice in the *Federal Register* of these proposed changes to Pennsylvania's regulatory program, which were submitted by PADEP on March 16, 2020. *See* 85 Fed. Reg. 81,864 (Dec. 17, 2020).

As discussed in further detail in the prior report, the proposed amendments include revisions to the determination of the value of collateral bonds, clarification that seeding does not restart the period of bond liability, and a revised definition of haul road under the anthracite mining regulations at 25 Pa. Code ch. 88. These revisions were required by OSMRE. The proposed changes also include the removal of the one-year time limit on temporary cessation of surface coal mining and anthracite mining operations under 25 Pa. Code chs. 87 and 88, respectively, changes to the calculation of civil penalties, and a revision to the definition of "surface mining activities" to incorporate by reference the federal definition at 30 C.F.R. § 701.5. These changes were not required by OSMRE but were made by PADEP for consistency with federal requirements. Finally, the March 2020 rulemaking included several changes unrelated to federal consistency, such as the definition of a preferred site for new coal refuse disposal facilities, calculation of remining financial guarantees and eligibility for remining financial incentives, and the procedure to calculate the amount of precipitation from a 24-hour storm event.

The public comment period on the proposed amendments closed on January 19, 2021. OSMRE will publish its decision on the proposed amendments in a forthcoming *Federal Register* notice.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart
Sean M. McGovern
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– Reporters –

Governor Wolf Vetoes Conventional Oil and Gas Wells Act

On November 18, 2020, Senate Bill 790 (SB 790), the Conventional Oil and Gas Wells Act, sponsored by Sen. Scarnati (R-Jefferson), was presented to Governor Tom Wolf for signature. Governor Wolf vetoed the bill on November 25, 2020. *See* Governor Wolf's Veto Letter for SB 790 (Nov. 25, 2020). SB 790 would have set a legislative framework for regulations for the conventional oil and gas industry in Pennsylvania. *See* Memorandum from Sen. Scarnati to All Senate Members, "Conventional Oil and Gas Wells Act" (June 6, 2019). In his veto letter, Governor Wolf acknowledged the difficulty in regulating conventional and unconventional operations under Pennsylvania's current program, which was updated by law in 2012 and by regulations for the unconventional industry in 2016. These updates were tailored to the new unconventional industry developing in the state, and placed new requirements on the conventional industry. Proposed regulations for the conventional industry were not promulgated in 2016 after the state legislature passed legislation requiring rules for the conventional industry to be promulgated separately from the unconventional rulemaking. *See* Pennsylvania Grade Crude Development Act, 58 Pa. Stat. §§ 1201–1208.

Governor Wolf cited several reasons for vetoing the bill and why he believed it posed a risk to the public health and environment. He characterized the bill as including "roll backs," stating that protections for drinking water, public resources, spills, and erosion and sediment control are weakened for the conventional industry, which he alleged violates regulations at a rate "three to four times" higher than the unconventional industry. Additionally, he stated that several parts of the bill were "likely" unconstitutional under the Pennsylvania Constitution.

Introduced in June 2019, SB 790 would create environmental rules and reporting requirements specific to the conventional oil and gas industry, which differs in many respects from the size and operations of the unconventional industry. While SB 790 was not enacted into law, the Pennsylvania Department of Environmental Protection (PADEP) is working on a new set of regulations for the conventional industry, independent of SB 790. As mentioned in PADEP's "2019 Oil and Gas Annual Report," it seeks to promulgate new regulations in several rulemaking packages amending the conventional regulations at 25 Pa. Code ch. 78. PADEP and the Pennsylvania Grade Crude Development Advisory Council (CDAC) had been working on legislative language to address the regulation of conventional well sites, and created a scoping document in 2018 on the potential for agreement on legislative or regulatory language. Over the past two years, discussions centered mostly on legislative language. However, PADEP developed the forthcoming rulemaking packages after it determined that the legislative discussions had not resulted in viable legislative language. PADEP recently discussed the draft conventional oil and gas rulemaking packages amending waste management and environmental protection performance standards with the Oil and Gas Technical Advisory Board at its September 17, 2020, meeting. *See* PADEP Regulatory Update (Oct. 7, 2020). The CDAC reviewed these draft rulemaking packages at its December 3, 2020, meeting, and will be generating comments on the draft rulemakings. Pennsylvania Grade Crude Oil Coalition president David Clark criticized moving forward with the proposed rulemaking packages so quickly. *See* Pa. Indep. Oil & Gas Ass'n, "DEP Advancing New Rules for Conventional Wells After Veto of Industry-Backed Bill," https://pioga.org/dep-advancing-new-rules-for-conventional-wells-after-veto-of-industry-backed-bill/. Several other conventional industry representatives pointed out issues with the draft rulemaking packages in public comments at the December 3 CDAC meeting. *See* CDAC Public Comments (Dec. 3, 2020), https://dced.pa.gov/download/cdac-public-comments-12-03-2020/. CDAC declined to hold another meeting in February 2021 to speed up review of the draft rulemakings, and will hold its next meeting in April 2021. *See* CDAC Agenda (Dec. 3, 2020), https://dced.pa.gov/download/CDAC%20Agenda%2012-03-20/?wpdmdl=104886.

The Governor's regulatory agenda from October 3, 2020, provides the latest update on the rulemaking time frame, estimating that the proposed rules could be presented to the Environmental Hearing Board in the second quarter of 2021. *See* 50 Pa. Bull. 5568 (Oct. 3, 2020).

Governor Wolf Approves Bill on Pipeline Emergency Response Plans

On November 25, 2020, Governor Tom Wolf signed into law House Bill 2293 (HB 2293), sponsored by Rep. Quinn (R-Delaware). *See* 66 Pa. Cons. Stat. Ann. § 1512 (effective Jan. 25, 2021). The new law requires public utilities operating pipelines to provide emergency response plans upon written request to the Secretary of the Pennsylvania Public Utility Commission, the Pennsylvania Emergency Management Agency, and the emergency management director for each county where the pipeline runs through a densely populated area. The law tasks the Public Utility Commission with enforcing its requirements, and violations of the law could result in an enforcement.

The accompanying memorandum on HB 2293 recognizes that highly confidential information exists in pipeline operators' emergency response plans. *See* Memorandum from Reps. Quinn & Comitta to All House Members, "Public Utilities Emergency Response Plan" (Jan. 16, 2020). If information contained in the response plan is confidential security information as defined under section 2 of the Public Utility Confidential Security Information Disclosure Protection Act, 35 Pa. Stat. § 2141.2, the law protects such information from disclosure to the public. However, for these protections to apply, the public utility must properly designate the confidential security information in the emergency response plan.

This bipartisan legislation is regarded as the first pipeline safety law, of approximately two dozen other proposed laws, to be enacted over the past three years.

Delaware River Basin Commission Approves Gibbstown LNG Terminal

On December 9, 2020, the Delaware River Basin Commission (DRBC), a federal agency created in 1961 by an interstate compact between Pennsylvania, Delaware, New Jersey, and New York, voted 4-0-1, with one abstention from New York, to approve a liquefied natural gas (LNG) terminal project by Delaware River Partners, a subsidiary of New Fortress Energy, in Gibbstown, New Jersey, along the Delaware River. *See* DRBC, Resolution for the Minutes and Accompanying Opinion (Dec. 9, 2020), https://www.state.nj.us/drbc/library/documents/ResForMinutes-and-Opinion120920_GLC_Dock2.pdf. The dock will permit liquefied hazardous gas and LNG from Pennsylvania to be loaded directly from truck or railcar to a marine vessel for overseas delivery. This site is reportedly the first in the nation that would allow delivery of LNG by rail.

The DRBC originally approved this project on June 12, 2019. *See* DRBC Docket D-2017-009-2 (June 12, 2019), https://www.state.nj.us/drbc/library/documents/dockets/061219/2017-009-2.pdf. However, the Delaware Riverkeeper and the Delaware Riverkeeper Network requested an administrative hearing after submitting comments arguing against approval of the project. The approval was affirmed by a hearing officer with the Pennsylvania Department of State on July 21, 2020, who found that the approval of the dock would not substantially impair or conflict with the DRBC's Comprehensive Plan, a document guiding the agency to consider the immediate and long-range development and use of the water resources of the Delaware River Basin. *See* Report of Findings and Recommendations, *In re DRBC Docket D-2017-009-2 Gibbstown Logistics Center Dock 2* (DRBC July 21, 2020). As part of the hearing, over a dozen expert and fact witnesses testified on topics involving the project and a lengthy administrative record was established. The DRBC next had to vote on the findings and recommendation of the hearing officer's report from July 21, 2020. Given the time required to review the report, the DRBC passed a motion moving the vote from September 10, 2020, to December 9, 2020. The approval was again affirmed by a vote of 4-0-1, with one abstention from New York.

Pennsylvania Supreme Court to Answer Questions on Legal Standards Applying to Zoning Objections to Unconventional Natural Gas Projects

On January 5, 2021, the Pennsylvania Supreme Court agreed to consider the role that courts should play and the standards that should apply when courts hear a zoning appeal over unconventional oil and gas operations. *See* Order Granting Appeal in Part, *Protect PT v. Penn Twp. Zoning Hearing Bd.*, Nos. 247 WAL 2020, 248 WAL 2020 (Pa. Jan. 5, 2021).

In this case, an energy company filed two applications for a special exception to develop unconventional gas wells on its property. These were approved by the zoning hearing board over Protect PT's objections regarding alleged concerns about public health and environmental issues presented through layperson and expert testimony. The zoning board found that the objectors did not establish that the proposed use would "create a high probability that an adverse, abnormal or detrimental effect will occur to public health, safety and welfare," which was a finding upheld by both the Westmoreland County Court of Common Pleas and the Commonwealth Court of Pennsylvania. *Protect PT v. Penn Twp. Zoning Hearing Bd.*, 238 A.3d 530 (Table), 2020 WL 3640001 (Pa. Commw. Ct. July 6, 2020). In upholding the finding of the board approving the special exceptions, the commonwealth court held that the evidence submitted by the objectors was not a basis to overrule the board. Some evidence dealt with particulars of construction and development, not the use of the land at issue, the latter being the proper inquiry according to the commonwealth court. *Id.* at *8. Further, the commonwealth court held that other evidence did not rise to the standard of showing a high probability that adverse effects to public health, safety, and welfare would occur. *Id.* In sum, the objectors failed to produce "sufficient, credible evidence" that if the ordinance requirements and conditions in the special exceptions are met, the use would still create a high probability of negative effects. *Id.* at *10. In a concurrence to the commonwealth court's affirmation, Judge McCullough noted his "concern" with the "legal framework employed to address, analyze, and dispose of the issues" concerning the evidence submitted by the objectors and other issues discussed by the court. *Id.* at *15 (McCullough, J., concurring).

On appeal to the Pennsylvania Supreme Court, the issues to be answered by the court are:

(1) Whether the Commonwealth Court's opinion conflicts with the Court's previous application of the capricious disregard of evidence standard and creates an issue of such substantial public importance as to require prompt and definitive resolution by this Honorable Court?

(2) Whether the Commonwealth Court's failure to meaningfully evaluate the cumulative impacts of developing multiple unconventional natural gas wells in close proximity to residential neighborhoods creating high probability of adverse, abnormal or detrimental effects on public health, safety and welfare and significantly altering the

> character of the community was an abuse of discretion which creates a question of first impression of such public importance which requires this Honorable Court's prompt and definitive resolution?

Order Granting Appeal in Part, at 1–2. Based on the briefing schedule, there is a chance oral arguments could be held as early as April 2021, but they are more likely to be held in October 2021, due to restrictions related to COVID-19 and remote hearing requirements.

PADEP Publishes Final Unconventional Guidance on Water Supply Impacts

On August 8, 2020, the Pennsylvania Department of Environmental Protection (PADEP) published notice in the *Pennsylvania Bulletin* of a final technical guidance document titled "Policy for the Replacement or Restoration of Private Water Supplies Impacted by Unconventional Oil and Gas Operations," No. 800-0810-002 (Aug. 8, 2020) (Final TGD), and the related comment and response document, outlining its policy and interpretation of the legal requirements to replace or restore private water supplies affected by unconventional oil and gas operations. *See* 50 Pa. Bull. 4091 (Aug. 8, 2020). The Final TGD replaced a previous interim final version in effect since October 2016 (Interim TGD). The Final TGD and the comment and response document can be viewed at http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=160355.

Section 3218 of Pennsylvania's Oil and Act of 2012 contains provisions relating to water supply impacts from unconventional oil and gas operations. 58 Pa. Cons. Stat. Ann. § 3218. Specifically, § 3218(a) requires an unconventional well operator to restore or replace water supplies affected by their operations. PADEP promulgated regulations implementing this provision at 25 Pa. Code § 78a.51. While it does not carry the force of law, the Final TGD provides operators and affected parties guidance on how PADEP implements the legal requirements when water supplies are affected by unconventional oil and gas operations. The Final TGD contains several substantive amendments from the Interim TGD.

Some changes in the Final TGD from the Interim TGD version include, but are not limited to:

- allows treatment of the impacted water supply as a temporary water supply;
- allows an operator to submit a request to PADEP for additional time to evaluate an impacted water supply to demonstrate that the impact may be temporary or may be corrected by remedial action at a location other than the water supply in "a short amount of time";
- states PADEP can require sampling for methane, ethane, and propane if it determines an operator is responsible for introducing those contaminants into the local aquifer or there is a concern they may be present in the new water supply source;
- specifies that the operator must report receipt of notice electronically to PADEP within 24 hours of receiving notice from a landowner, water purveyor, or affected person that a water supply has been affected by pollution or diminution, and that water supply replacement plans should be shared among any affected persons and their consultants;
- adds a requirement that operators must comply with certain industry standards when utilizing plumbing accessories and equipment associated with the implementation of temporary water supplies or permanent restoration or replacement of private water supplies; and
- includes new references and citations to PADEP's broad authority under the Clean Streams Law (35 Pa. Stat. §§ 691.1–.1001) to issue orders, inspect private and public property, and otherwise investigate "all facts" relating to pollution of waters of the Commonwealth, including private water supply complaints. *See* 35 Pa. Stat. § 691.305.

PADEP Publishes Draft Guidance on Spill Policy Under Pennsylvania's Clean Streams Law and NPDES Regulations

On August 8, 2020, the Pennsylvania Department of Environmental Protection (PADEP) published notice in the *Pennsylvania Bulletin* of a new draft technical guidance document entitled "Guidance on Notification Requirements for Spills, Discharges, and Other Incidents of a Substance Causing or Threatening Pollution to Waters of the Commonwealth Under Pennsylvania's Clean Streams Law," No. 383-4200-003 (Aug. 8, 2020) (Draft TGD), outlining its spill policy interpreting legal requirements under the Clean Streams Law (35 Pa. Stat. §§ 691.1–.1001 and implementing regulations at 25 Pa. Code ch. 91) and Pennsylvania's National Pollutant Discharge Elimination System (NPDES) regulations (25 Pa. Code ch. 92a). *See* 50 Pa. Bull. 4091 (Aug. 8, 2020). The Draft TGD and associated public comments are available at https://www.ahs.dep.pa.gov/eComment/.

Pennsylvania has broad notification requirements for spills, releases, discharges, or other incidents that cause or threaten pollution of "waters of the Commonwealth," defined to include groundwater. 35 Pa. Stat. § 691.1. Generally, a person must notify PADEP if, by accident or other activity, a toxic or other substance that would endanger downstream users of waters of the Commonwealth results in pollution, creates the danger of pollution, or damages property, enters, or is placed so that it might enter waters of the Commonwealth. 25 Pa. Code § 91.33(a). This regulation does not provide objective or quantifiable thresholds for determining what spills, releases, discharges, or other events require reporting. Additionally, it is not limited to certain industries or permitted facilities, but rather applies any time there is an incident like a discharge or threat of discharge into waters of the Commonwealth.

This regulation is incorporated by reference in several regulatory programs, including Pennsylvania's NPDES program. NPDES permit holders must comply with the spill reporting requirements under 25 Pa. Code ch. 92a. Specifically, § 92a.41(b) requires that NPDES permittees comply with the immediate oral notification requirements of § 91.33. In addition, § 92a.41(b) interprets that immediate oral notification requirement to mean as soon as possible, but not later than four hours after the NPDES permittee becomes aware of the incident causing or threatening pollution, and requires a written submission to PADEP within five days of becoming aware of the incident.

The purpose of the Draft TGD is to provide guidance on the immediate notification requirements for compliance under these programs. The Draft TGD applies to all persons and operations subject to reporting requirements under § 91.33, including the oil and gas industry, which has its own spill reporting requirements in separate regulations. *See* 25 Pa. Code §§ 78.66, 78a.66; PADEP, "Addressing Spills and Releases at Oil & Gas Well Sites or Access Roads," No. 800-5000-001 (Sept. 21, 2013).

PADEP's position in the Draft TGD is that there are no objective threshold requirements for what incidents need to be reported under § 91.33(a), which tracks the regulatory language. The Draft TGD recommends erring on the side of notification when there is some question as to whether reporting is required, and it states that PADEP may consider the decision to notify when exercising its enforcement discretion. The Draft TGD also uses language slightly broader than the language of § 91.33(a). Under this provision, notification is triggered if an incident "would" endanger downstream users, result in pollution, create a danger of pollution, or damage property. The Draft TGD replaces "would" with the term "may," arguably expanding the scope. Other information in the Draft TGD defines who the "responsible parties" required to notify are and provides examples of how responsible parties respond to spills, releases, discharges, and other incidents. The Draft TGD does not clarify its interaction with requirements for reporting spills under the oil and gas regulations or policy. As noted by the Marcellus Shale Coalition in its comments on the Draft TGD, some of the oil and gas notification requirements and PADEP's other programs have notification time frames and applicability thresholds inconsistent with what is required under § 91.33(a) and the Draft TGD. *See, e.g.*, 25 Pa. Code §§ 78.66, 78a.66a.

PADEP Publishes Unconventional Pressure Barrier Guidance for Comment

On August 29, 2020, the Pennsylvania Department of Environmental Protection (PADEP) published notice in the *Pennsylvania Bulletin* of a new draft technical guidance document entitled "Guidelines for Development of Operator Pressure Barrier Policy for Unconventional Wells," No. 800-0810-003 (Aug. 29, 2020) (Draft TGD). *See* 50 Pa. Bull. 4459 (Aug. 29, 2020). The Draft TGD underwent public comment from August 29 to September 28, 2020. The Draft TGD and associated comments can be found at https://www.ahs.dep.pa.gov/eComment/. PADEP has been developing this long-awaited guidance for several years. PADEP previously stated that it was developing pressure barrier policy guidance as part of Pennsylvania's unconventional oil and gas regulations to assist unconventional operators in complying with pressure barrier policy requirements. *See* PADEP, Chapter 78/78a Comment Response Document, Part 1 of 2, "Environmental Protection Performance Standards at Oil and Gas Well Sites," Comment No. 764 (2016). The unconventional oil and gas regulations went into effect in 2016. *See* 46 Pa. Bull. 6431 (Oct. 8, 2016). It is unclear why the guidance has taken years to develop. Given the recent comment period, the Draft TGD could be approaching finalization; however, there are no deadlines by which PADEP must finalize the Draft TGD.

The guidance is meant to provide unconventional operators guidelines on how to develop a pressure barrier policy prior to drilling a well and in other required circumstances. A pressure barrier policy is a component of a preparedness, prevention, and contingency plan, which is required under the unconventional oil and gas regulations. 25 Pa. Code § 78a.55(a), (d). PADEP asserts operators must consider using pressure barriers during unconventional operations including, but not limited to, drilling, hydraulic fracturing, completion, alteration, plugging, workover activities, and maintenance or repair activities. When identified as necessary, at least two mechanical pressure barriers capable of being tested during well drilling and completion operations are required between the open formation and the atmosphere. *Id.* § 78a.72(i). An operator is also permitted to determine that a pressure barrier policy is applicable to more than one well based on subsurface conditions. PADEP defines mechanical pressure barriers in the Draft TGD to include well heads, ram-type blow-out preventers, and annual-type blow-out preventers. If an operator notices a well control incident like a loss of control or control emergency, an operator must report this incident to PADEP within two hours. In addition to outlining the requirements of a pressure barrier policy, the Draft TGD includes worksheets developed by PADEP to assist operators with developing a pressure barrier policy.

PADEP Releases 2019 Oil and Gas Annual Report

On September 14, 2020, the Pennsylvania Department of Environmental Protection (PADEP) released the "2019 Oil and Gas Annual Report" (Report). The Report is an annual publication that highlights program initiatives, production and permitting statistics, enforcement data, and other topics of the past year.

The Report provides data collected from the past year and older annual data from previous years. Several highlights of the data include:

- *Inspections*. According to PADEP, in 2019, it completed 35,324 compliance inspections at conventional and unconventional well sites, 1,549 fewer than 2018.
- *Enforcement*. A total of $4,097,545 in fines and penalties was collected in 2019, pushing the total amount collected to $43.7 million over the past 10 years. This number was slightly down from the 2018 penalty amount, but up from 2017. Additionally, compared to 2018 levels, alleged compliance violations issued to unconventional and conventional operators decreased to 985 from 1,043, and to 1,763 from 3,017, respectively.
- *Production*. Natural gas production increased from 6.1 trillion cubic feet in 2018 to 6.8 trillion cubic feet in 2019.
- *Permits and Operations*. PADEP issued 1,475 unconventional well permits in 2019, 393 fewer than 2018. A total of 615 unconventional wells were drilled during 2019, around 162 less than 2018. A total of 172 conventional wells were drilling during 2019, an increase of 32 wells from 2018. The average time to process an oil and gas permit improved by several days in 2019 for both the Northwest and Southwest district offices.
- *Produced Fluid Management*. As of 2019, operators achieved a 90% reuse or recycle rate of produced fluids. There were 11 active underground injection control (UIC) disposal wells in Pennsylvania. PADEP estimates that 8% of produced fluids from oil and gas sites was disposed of at UIC wells in Pennsylvania, Ohio, or West Virginia, and the remaining 2% was managed by other wastewater treatment options.

In addition to providing statistics, PADEP discussed its efforts and anticipated outlook on projects, initiatives, and regulatory actions currently underway or anticipated in the future. In 2019, working groups met to address topics like natural gas storage, permit processing efforts, and groundwater study issues, among others. PADEP states that it is analyzing alternative methods of funding given the fluctuation of oil and gas permits per year. In the regulatory context, the Report confirms PADEP's intent to move forward with updating conventional oil and gas regulations on environmental protection performance standards via several rulemakings in late 2020. PADEP is also reviewing its role in issuing UIC permits. Pennsylvania does not have primacy to implement the UIC program. Currently, a UIC permit applicant must first obtain approval from the U.S. Environmental Protection Agency, and then a well permit from PADEP. The agencies are exploring the possibility of transitioning this two-step process to a concurrent review process by both agencies.

Editor's Note: The last four reports were timely submitted for publication in the previous issue of this *Newsletter* but were inadvertently omitted.

TEXAS – OIL & GAS

William B. Burford
– Reporter –

Continuous Development Clause's Right to "Accumulate" Days Between Wells Held Ambiguous

In *Endeavor Energy Resources, L.P. v. Energen Resources Corp.*, 615 S.W.3d 144 (Tex. 2020), the Texas Supreme Court considered a 2006 oil and gas lease covering 11,300 acres in Howard County, Texas. The lease included a continuous development clause under which, after the end of the lease's three-year primary term, it would terminate as to any land not within a producing proration unit whenever "a subsequent well is not commenced within one hundred fifty (150) days from the completion of a preceding well," subject to a proviso that formed the basis for the parties' dispute: "Lessee shall have the right to accumulate unused days in any 150-day term during the continuous development program in order to extend the next allowed 150-day term between the completion of one well and the drilling of a subsequent well." *Id.* at 147.

Endeavor Energy Resources, L.P. (Endeavor), having acquired the lessee's interest and then having drilled 12 wells on the lease between the end of the primary term and late 2014, commenced a thirteenth well on November 12, 2015, 320 days after the completion of the last previous well and a few days after Energen Resources Corp. (Energen) had obtained a lease from Endeavor's lessor and filed suit for a determination that Endeavor's lease had partially terminated. Endeavor's position was that it had drilled many of its wells in advance of the 150-day deadline and had thus accumulated 377 days, in the aggregate, to commence its thirteenth well. Energen argued, to the contrary, that any number of days less than 150 that Endeavor took to commence a well since the completion of the preceding one could be carried over only to the very next well, not any subsequent ones. Thus, according to Energen's interpretation, any number of days "saved" during the course of Endeavor's drilling before its eleventh well were irrelevant, and, because there had only been 36 "unused" days between Endeavor's eleventh and twelfth wells, Endeavor's deadline to commence the thirteenth well was July 1, 2015, 186 days after the completion of the twelfth well. Because Endeavor had not met that deadline, argued Energen, the lease had terminated except as to producing proration units, and Energen's own lease was now the effective one. *Id.* The trial court granted summary judgment to Energen, and the court of appeals affirmed. *See* Vol. XXXV, No. 4 (2018) of this *Newsletter*.

The court began its analysis with summaries of the parties' respective positions. Energen emphasized that the unused-time provision referred to the 150-day "term" between wells as singular rather than plural, indicating that unused days from multiple terms could not be combined, and that the provision that unused days from any one term roll over only to the "next" term meant that unused days extend only to the immediately following term and not to later ones. *Endeavor*, 615 S.W.3d at 149–50. Endeavor argued that the label "150-day term" must be understood as a generic label used to describe both unextended terms and terms extended by unused days from earlier wells, so that the "next allowed 150-day term" could refer to a term actually longer than 150 days, pointing out that the parties agreed that unused days may be carried forward at least once so that neither truly read the words "150-day term" to always refer to a term of exactly that length. *Id.* at 150. The court could not, it concluded, reject either interpretation as unreasonable based on the lease's operative text alone. *Id.* at 151. Energen's emphasis on the word "next," the court believed, merely begged the question of whether unused days carried over from one term become part of the ensuing one. *Id.* Endeavor, on the other hand, placed outsized emphasis on the word "accumulate" as connoting a right to stack an accumulation of days over multiple periods. *Id.* at 152.

Before declaring a contract ambiguous, a court must seek to understand its objective meaning according to its plain language but may, if the text is inconclusive, consider any extrinsic circumstances that shed light on the objective meaning conveyed by the text, the court continued. *Id.* at 152–53. In this connection Endeavor theorized that the primary benefit for which the lessor bargained was the completion of a new well, on average, every 150 days, whereas the lessee sought flexibility in its drilling schedule. *Id.* at 153. Energen's contrary theory was that the lessor was instead primarily interested not in ensuring a certain average duration of gaps between wells but in avoiding excessively long ones. *Id.* at 154. Both parties thus advanced plausible understandings of the provision's commercial purpose, the court observed, but without clearer textual instruction in the parties' agreement, resolving the case based on what the court thought the parties meant to accomplish would, it said, impermissibly rewrite their agreement. *Id.* Neither side's arguments regarding the lease's commercial purposes were sufficient, the court declared, to "break the tie" created by the lease's ambiguous language. *Id.*

Because the lease was reasonably susceptible to more than one meaning, the court held, it was ambiguous. *Id.* at 155. Further, because of the special rule of construction that contractual language in an oil and gas lease will not be held to impose a special limitation on the grant unless it is so clear, precise, and unequivocal that it could reasonably be given no other meaning, the disputed provision could not operate as a special limitation. *Id.* The court therefore rendered judgment for Endeavor on the question of leasehold title. The result, it would seem, is the same as though the court had declared the clause at issue unambiguous and properly construed as Endeavor urged.

This decision certainly will incentivize lessees to forcefully argue ambiguity in cases in which the viability of an oil and gas lease depends on interpretation of its wording. Given the marked reluctance of Texas courts to find ambiguity even while giving respectful treatment to interpretations they ultimately reject, its actual impact may be negligible.

Accommodation Doctrine Imposes No Restriction on Surface Use Until Mineral Development Is Sought

The court in *Lyle v. Midway Solar, LLC*, No. 08-19-00216-CV, 2020 WL 7769632 (Tex. App.—El Paso Dec. 30, 2020, no pet. h.), affirmed summary judgment in favor of the surface owner of Section 14, a 315-acre tract of land in Pecos County, Texas, and its lessee against the owners of an undivided interest in the minerals.

Gary Drgac, the surface owner, leased Section 14 to Midway Solar, LLC (Midway), a solar energy developer, which then covered 215 acres of the tract with its solar panels, leaving an 80-acre tract on the north end and a 17-acre strip on the south end as sites for future oil and gas drilling. The Lyles, owners of an undivided 27.5% mineral interest in the land, filed suit in trespass, alleging that construction of the solar facility had destroyed or greatly diminished the value of their mineral estate and requesting an injunction to remove the solar panels and related transmission lines. *Id.* at *1.

The court of appeals agreed with the trial court and with Drgac and Midway that they owed no duty to the Lyles to accommodate their right to use the surface of Section 14 because the Lyles had not developed their mineral estate and had no current plans to do so. The court acknowledged that where a surface owner desires to use land in a manner that conflicts with mineral development, the surface owner carries the burden, under the accommodation doctrine, "to show that (1) the mineral owner's use of the surface completely precludes or substantially impairs the surface owner's existing use, and (2) there is no reasonable alternative method available to the surface owner by which the existing use can be continued." *Id.* at *7. However, after rejecting the Lyles' argument that particular wording of the deed that had severed the surface and mineral estates had rendered the accommodation doctrine inapplicable, the court held that until the Lyles sought to develop their minerals, the surface owner and lessee owed them no duty respecting surface usage. *Id.* at *11. Although Midway must yield to the degree mandated by the accommodation doctrine if the Lyles should exercise their right to use the surface for mineral development, the court reasoned, there is nothing to be accommodated while the Lyles are not exercising that right. *Id.* Were it otherwise, the court continued, "a mineral owner who undertakes no efforts to develop the mineral estate could claim damages for any surface activities that might hinder—at some point in the future—the exploration for oil and gas." *Id.* "There is simply no logic," the court declared, "in allowing trespass damages today for a mineral estate that might never be developed." *Id.* Any such claim is premature until the Lyles actually seek to develop their mineral estate, the court concluded, modifying the trial court's judgment so that the Lyles' claims were dismissed without prejudice. *Id.* at *12.

The court went on to reverse the trial court's denial of the Lyles' motion for summary judgment on quiet title claims against mineral owners of adjoining land. Midway had obtained agreements from a number of mineral owners in land in the vicinity, but outside Section 14, waiving their rights to surface use. In several instances this was done by way of an inartfully drafted form of agreement that made it appear those owners asserted some interest in Section 14. The court agreed with the Lyles that unless the agreements made it clear that the applicable mineral ownership was only in other land, not in Section 14, these agreements cast clouds on the Lyles' title that were not altogether removed by Midway's unilateral disclaimer of any right in Section 14 under them. *Id.* at *15.

Deed's Reservation of "Double Fraction" of 1/2 of 1/8 of Minerals Held Limited to 1/16, Not 1/2, Mineral Interest

The court in *Van Dyke v. Navigator Group*, No. 11-18-00050-CV, 2020 WL 7863330 (Tex. App.—Eastland Dec. 31, 2020, no pet. h.) (mem. op.), construed the following mineral reservation in a 1924 deed from Geo. H. and Frances E. Mulkey to G. R. White and G. W. Tom: "It is understood that one-half of one-eighth of all minerals and mineral rights in said land are reserved in grantors, Geo. H. Mulkey and Frances E. Mulkey, and are not conveyed herein." *Id.* at *1. The successors to the interest of the Mulkeys, whom the court called the "Mulkey Assignees," maintained that in light of the "estate misconception" prevalent at the time of the 1924 deed, the reservation should be construed as 1/2 of the minerals underlying the land conveyed. *Id.* at *2. The successors to the interest conveyed to White and Tom, referred to by the court as the "White Assignees," countered that the deed's reservation was unambiguous and that the deed contained no conflicting provisions so that it plainly reserved only a 1/16 mineral interest and conveyed 15/16 to White and Tom. *Id.* The court agreed with the White Assignees and affirmed the trial court's summary judgment in their favor.

The estate misconception theory relied upon by the Mulkey Assignees, the court explained, "refers to a once-pervasive misunderstanding that, if an owner executed a mineral lease, he retained only one-eighth of the minerals [(one-eighth being the standard lessor's royalty by the 1920s)] rather than a fee simple determinable with the possibility of reverter in the whole." *Id.* at *3. Surrounding circumstances may inform the meaning of the words used in an agreement, the Mulkey Assignees argued, and here the estate misconception theory was a "key surrounding circumstance that, when taken into account, renders ambiguous the 1924 Deed's use of a double fraction" in the mineral reservation. *Id.* The court disagreed. The application of the estate misconception theory is not new to Texas oil and gas jurisprudence, it observed. *Id.* Rather, what would be new would be to "apply the theory to construe a reservation in which clear language is employed and in which there is an absence of contradictory fractions or terms." *Id.*

In each of several cases relied upon by the Mulkey Assignees, the court pointed out, the fractional interests conveyed or reserved were described inconsistently within the instruments that created them, requiring the reviewing courts to harmonize the conflicting fractions. *Id.* at *4. In this case, by contrast, there were no conflicting provisions to harmonize. Here the language in the deed was clear: the reservation was one-half of one-eighth of the minerals, and there was no other language employed to describe it. *Id.* Moreover, the court remarked, "[t]he Mulkeys could not have been operating under the estate misconception theory because, at the time of the deed, [there was no lease and the Mulkeys] owned all the attributes of the mineral estate . . . ." *Id.* at *5.

The Mulkey Assignees further claimed that circumstantial evidence established their ownership of one-half of the minerals under the presumed grant doctrine, or at least raised a fact issue. The court began its analysis of that argument by observing that "[t]he object of the presumed grant theory is to settle titles in situations where it was understood that property belonged to one who claimed the land for a long time but did not have complete record title," and that to establish title by the doctrine the claimant must show "(1) a long asserted and open claim, adverse to that of the apparent owner; (2) nonclaim by the apparent owner; and (3) acquiescence by the apparent owner in the adverse claim." *Id.* The Mulkey Assignees asserted they could establish those elements through a series of conveyances, leases, ratifications, division orders, contracts, probate inventories, stipulations, and other documents in which the White Assignees appeared to acknowledge the Mulkey Assignees' one-half mineral ownership. *Id.*

Rejecting the presumed-grant argument, the court noted that although the existence of a gap in the claimant's chain of title is not an express element, courts have typically applied the presumed grant argument in cases where a party's lack of complete record title to land it has claimed for a long time is due to such a gap. *Id.* at *6. Here the Mulkey Assignees were seeking to show the existence of a "gap in interest" rather than a gap in the chain of title. *Id.* The Mulkey Assignees' ownership interest was already established under the terms of the 1924 deed. "Because the presumed grant doctrine cannot operate to change the quantum of interest as expressed in the very deed relied upon by the Mulkey Assignees for their source of title," the court declared, "the Mulkey Assignees failed to establish ownership of one-half of the minerals as a matter of law," and there was "no genuine issue of material fact as to their claim of a presumed grant." *Id.* at *7.

Editor's Note: The reporter's law firm has represented the Navigator Group, some of the White Assignees, in this case.

Ad Valorem Taxes Held Not Assessable Against Interest in Land in Another County Pooled into Unit Crossing County Line

The Chambers family owned mineral interests in 652 acres located in Shelby County, Texas. Oil and gas leases covering their interests were pooled into two gas units containing land in both Shelby County and San Augustine County. After the San Augustine County Appraisal District (SCAD) sought to appraise the Chamberses' interests in the pooled unit for San Augustine County ad valorem taxes, the court of appeals in *Chambers v. San Augustine County Appraisal District*, 514 S.W.3d 420 (Tex. App.—Tyler 2017, no pet.), concluded that because the Chambers leases authorized pooling but expressly denied that pooling effected a cross-conveyance of interests, SCAD had not established that the Chamberses owned taxable minerals in San Augustine County or had an obligation to pay taxes in that county and remanded the cause to the trial court. *See* Vol. XXXIV, No. 1 (2017) of this *Newsletter*. In *San Augustine County Appraisal District v. Chambers*, No. 12-20-00128-CV, 2021 WL 219300 (Tex. App.—Tyler Jan. 21, 2021, no pet. h.), the court rejected SCAD's second bite at the apple.

On appeal of summary judgment for the Chamberses after remand, SCAD argued that by signing division orders that acknowledged their ownership in the pooled units and accepting royalty payments pursuant to the division orders, the Chamberses had waived their right to rely on the cross-conveyance language in their leases. The court disagreed. The leases expressly prevented the presumed cross-conveyance that might have been effected by pooling, and the division orders included provisions that they did not amend leases. *Id.* at *2. The Chamberses were not contesting unitization, and unitization, in the absence of cross-conveyance, did not entitle SCAD to assess taxes on the Chambers interests in the pooled units. *Id.* at *3. "Whether there is a cross-conveyance depends on the lease language," the court observed, "not the presence of unitization." *Id.* Moreover, it concluded, no Texas statute provides for taxation of minerals outside the boundaries of the taxing unit merely because they are included in a production unit pursuant to a pooling agreement nor that pooling results in a cross-conveyance. *Id.* at *4.

Lender's Security Interest Held Superior to Oil Producers' Statutory Security Interests in Oil Proceeds Under Choice-of-Law Principles

Tex. Bus. & Com. Code § 9.343 is a non-standard provision of Texas's version of the Uniform Commercial Code (UCC). It grants to oil and gas producers a first-priority purchase money security interest in oil and gas and their proceeds in the hands of the first purchaser of the oil and gas, without the need for the filing of a financing statement or other action on the part of the producers. The court in *In re First River Energy, L.L.C.*, 986 F.3d 914 (5th Cir. 2021), held that where that first purchaser is an entity organized in Delaware, a lender whose security interest in the proceeds is perfected under the Delaware UCC instead has priority over any such security interests of Texas oil producers.

First River Energy, L.L.C. (FRE) was a midstream service provider organized under Delaware law but headquartered in Texas. It bought oil from producers in Texas and Oklahoma, which it then resold to downstream purchasers. When it discontinued business at the end of 2017 and sought bankruptcy protection, the producers that had sold oil to FRE were left unpaid for the previous month's deliveries. The producers filed proofs of claim asserting their statutory first-priority security interests under the Texas UCC against the proceeds due FRE from its resale of the oil. FRE's lender, Deutsche Bank Trust Company Americas, claimed first priority of its security interest under a 2015 credit agreement, perfected by filing financing statements in Delaware. *Id.* at 917.

The Texas UCC, the court pointed out, applies the local law of the jurisdiction where the debtor is "located" to questions of the perfection and priority of security interests, and defines the debtor's "location" in the case of a limited liability company such as FRE as its state of organization. *Id.* at 925. Because the Delaware UCC requires the filing of financing statements and contains no provision recognizing the priority of security interests such as that afforded Texas producers by the Texas UCC, the court concluded, the bank's security interest in FRE's sale proceeds, perfected by UCC-1 financing statements filed in Delaware, was entitled to priority over the Texas producers' unperfected security interests. *Id.*

The Texas producers argued unsuccessfully that their rights as secured creditors were governed by Texas law, not Delaware law, and thus entitled to first priority. The resolution of this argument, in the court's analysis, turned on the interpretation of Tex. Bus. & Com. Code § 9.343(p), which provides that "[t]he rights of any person claiming a security interest or lien created by this section are governed by the other provisions of this chapter except to the extent that this section necessarily displaces those provisions." *FRE*, 986 F.3d at 922 (alteration in original) (emphasis omitted). Enforcing the provisions of the chapter (UCC Article 9) applying the law of the debtor's location to questions of perfection and priority would, the producers argued, eviscerate the intended scope of Texas's statute, rendering its protection useless whenever a debtor is organized outside Texas. *Id.* at 925. Section 9.343, the court pointed out, was deliberately enacted within the Texas UCC, and although UCC Article 9 does not extend to liens created by "another statute" of the state, the section was not created by "another statute" but is included within, not singled out and excluded from, the scope of Article 9's coverage. *Id.* at 926. The producer's statutory security interest under § 9.343 did not, as the producers argued, "necessarily displace" the rest of Article 9 but must be construed as part of it. *Id.* at 927.

Conversely, the court in the same opinion upheld the bankruptcy court's decision that Oklahoma oil producers who had sold production to FRE, unlike the Texas producers, were entitled to priority over the bank's security interest pursuant to legislation similar to that of Texas. *Id.* at 930–31. The difference was that the Oklahoma statute is outside that state's UCC, enacted in response to a 2009 bankruptcy court decision similar to this one. The Texas legislature should take note, the court here said in the introduction to its opinion. *Id.* at 917.

WEST VIRGINIA – OIL & GAS

Andrew S. Graham
– Reporter –

West Virginia Supreme Court of Appeals Affirms Lower Court's Refusal to Imply Pooling Rights into Oil and Gas Lease

In *Ascent Resources-Marcellus, LLC v. Huffman*, 851 S.E.2d 782 (W. Va. 2020), the West Virginia Supreme Court of Appeals affirmed a lower court decision that an implied right to pool and unitize oil and gas leases could not be inferred from an otherwise unambiguous lease.

In 1980, D. & H. Oil Company acquired an oil and gas lease covering an undivided one-half interest in the oil and gas underlying a 94-acre tract of land in Tyler County, West Virginia, which lease is held by production from multiple vertical wells on the tract. In 2016, after acquiring this lease, Ascent Resources-Marcellus, LLC (ARM), the owner of the remaining one-half interest in the oil and gas, filed a declaratory judgment action in the Circuit Court of Tyler County seeking recognition that the lease contained an implied covenant to pool or unitize the lease with other mineral interests. ARM conceded that the lease contained no language expressly permitting the right to pool or unitize, but ARM maintained that such a right should be implied so that it could form a drilling unit large enough to accommodate the drilling of a horizontal well at least 2,500 feet in length, which would be necessary to develop the Marcellus Shale formation. According to ARM, the 94-acre tract alone was too small to support the drilling necessary for its planned Marcellus development. *Id.* at 784.

ARM filed a motion for summary judgment and asked the court to imply the following five paragraphs into the lease:

> 1. Lessee shall have the right to pool, unitize, or combine all or parts of the Leasehold with other lands, whether contiguous or not contiguous, leased or unleased, whether owned by Lessee or by others, at a time before or after drilling, to create drilling or production units.
>
> 2. Pooling or unitizing in one or more instances shall not exhaust Lessee's pooling and unitizing rights, and Lessee shall have the right to change the size, shape, and conditions of operation of any unit created and to make concomitant changes in payments.
>
> 3. Lessee shall allocate production from each well in a unit among each of the leases in the unit as a percentage of that leasehold's acreage in the unit compared to the total leasehold acreage in the unit. Lessee shall then pay the royalties specified in each lease based upon the sale price of the production allocated to that lease.
>
> 4. Drilling, operations in preparation for drilling, production, shut-in production from the unit, or payment of royalty on any part of the unit (including non-Leasehold land) shall have the same effect upon the terms of the Subject Lease as if a well were located on, or the subject activity were attributable to, the Leasehold.
>
> 5. Lessee shall record among the land records of the county the declaration of pooling and any amendments thereto and attempt to furnish a copy to Lessor or their known successors and assigns, although failure to furnish a copy to any Lessor shall not operate to void or terminate any drilling unit that has been formed.

Id. at 785.

In support of its motion, ARM attached a declaratory judgment order granted by a different judge of the Circuit Court of Tyler County in *American Energy-Marcellus, LLC v. Mary Jean Templeton Poling*, No. 15-C-34-H (Cir. Ct. of Tyler Cty. Apr. 15, 2016), in which the court implied into an oil and gas lease the five terms sought by ARM in its motion for summary judgment. *Ascent*, 851 S.E.2d at 786 n.3. ARM also attached to its motion an expert's affidavit, which opined that the proposed terms were customary pooling terms currently used in the oil and gas industry. *Id.* at 785–86.

The court denied ARM's motion for summary judgment, rejected its request for a declaratory judgment, and held that (1) the lease granted no express pooling rights; (2) the lease was unambiguous; (3) the court could not imply new pooling rights into the lease; and (4) if the court implied such rights into the lease, doing so would impose burdens on the oil and gas estate that had not been bargained for or contemplated when the lease was granted in 1980. *Id.* at 786. ARM appealed.

The West Virginia Supreme Court of Appeals affirmed the lower court's decision and held that, even though the West Virginia courts have previously incorporated certain implied covenants into oil and gas leases, such as the implied covenant to develop the minerals, the implied covenant to market the oil and gas, and the implied covenant to protect against drainage, it could not imply into an otherwise unambiguous lease the implied right to pool. In support of its ruling that the lower court did not err in finding that the lease was unambiguous, the court noted that the lease contained "no language suggesting that pooling and unitization were considered by the parties when they negotiated and executed the document," *id.* at 788, but, in a footnote, the court recognized that the U.S. District Court for the Northern District of West Virginia, in *Stern v. Columbia Gas Transmission, LLC*, No. 5:15-cv-00098, 2016 WL 7053702 (N.D. W. Va. Dec. 5, 2016), held that a lease that contained language permitting operations "alone and conjointly with other lands for the production and transportation of oil and gas" permitted the lessee to exercise the right to pool. *Ascent*, 851 S.E.2d at 788 n.6.

Federal Appeals Court Upholds Lessee's Deduction of Post-Production Costs Because Lease Satisfied All Three Prongs of West Virginia's *Tawney* Test

In *Young v. Equinor USA Onshore Properties, Inc.*, 982 F.3d 201 (4th Cir. 2020), the U.S. Court of Appeals for the Fourth Circuit held that an oil and gas lease properly provided for the method of calculating deductions of post-production costs from royalties due under the lease under West Virginia's three-prong *Tawney* test. Reversing a decision by the U.S. District Court for the Northern District of West Virginia, the court rejected the lower court's determination that the *Tawney* test required a "mathematical formula" and further clarified that "*Tawney* doesn't demand that an oil and gas lease set out an Einsteinian proof for calculating post-production costs." *Id.* at 208.

Travis and Michelle Bee Young granted an oil and gas lease covering lands in Ohio County, West Virginia, under which SWN Production Company (SWN) and Equinor USA Onshore Properties, Inc. (Equinor), had the right to drill and operate wells and the right to pool the Youngs' lease with other mineral interests. The lease provided for a royalty share of 14% of the "net amount realized by Lessee, computed at the wellhead" on actual volumes of gas sold from the land. *Id.* at 203. The lease further provided that this net amount would be calculated by deducting "post-production costs incurred by Lessee between the well-head and the point of sale" from "the gross proceeds received by Lessee from the sale of oil and gas." *Id.* at 203–04. The lease further defined "post-production costs" to include costs and expenses for treating, processing, separating, transporting, compressing, and metering the oil and gas, as well as sales charges related to the sale of the gas and any other costs and expenses regarding the handling of the gas between the well-head and sales point. The lease also permitted the lessee, if it used its own pipelines or equipment, to deduct reasonable depreciation and amortization expenses along with the cost of capital and a reasonable return on its investment. *Id.* at 204.

After SWN began deducting post-production costs from the Youngs' royalty payments, the Youngs filed suit in state court against SWN and Equinor, arguing that such deductions were not permitted under West Virginia law because the lease did not meet the requirements for allocating post-production costs to the lessors. The case was removed to the Northern District of West Virginia and the parties filed cross-motions for summary judgment.

The district court granted summary judgment to the Youngs, noting the presumption under West Virginia law that a lessee bears all post-production costs unless the lease provides otherwise. In *Estate of Tawney v. Columbia Natural Resources, LLC*, 633 S.E.2d 22 (W. Va. 2006), the West Virginia Supreme Court of Appeals held that the lessee may rebut the presumption (and allocate post-production costs to the lessor) by satisfying requirements that the lease (1) "expressly provide that the lessor shall bear some part of the [post-production] costs"; (2) "identify with particularity the specific deductions the lessee intends to take from the lessor's royalty"; and (3) "indicate the method of calculating the amount to be deducted from the royalty for such post-production costs." *Young*, 982 F.3d at 205 (alteration in original) (quoting *Tawney*, 633 S.E.2d at 30). The district court agreed with the Youngs that the lease failed to satisfy the third prong of the *Tawney* test because it did not properly provide for the method of calculating the amount to be deducted from the Youngs' royalties. *Id.* SWN and Equinor appealed.

On appeal, SWN and Equinor argued that while the lease satisfied the *Tawney* test for deducting post-production costs, they also had the right to take deductions because the lease disclaimed any implied duty to market (and thus *Tawney* did not apply). The lessees also asked the court to certify to the West Virginia Supreme Court of Appeals the question of whether *Tawney* remained good law, and if so, whether the lease satisfied the *Tawney* test. *Id.*

The Fourth Circuit chose not to certify any questions to the West Virginia court. Rather, the court held that the lease satisfied the *Tawney* test and was consistent with West Virginia law. Rejecting the district court's decision that the "method of calculation" prong of the *Tawney* test required a "mathematical formula," the court held that, by its plain language, *Tawney* merely requires that if an oil and gas lease expressly allocates some post-production costs to the lessor, the lease must identify which costs and how much of those costs will be deducted from the lessor's royalties. *Id.* at 208. To calculate the Youngs' royalties, the net amount is multiplied by 14% (the Youngs' royalty rate) and by their fractional interest in the tract (if applicable), then multiplied by their fractional share of the lease acreage included in the total pooled acreage. *Id.* The court explained that the lease's formula essentially mirrored the "work-back" method of calculation approved by the West Virginia court in *Leggett v. EQT Production Co.*, 800 S.E.2d 850 (W. Va. 2017). *Young*, 982 F.3d at 208–09; *see* Vol. XXXIV, No. 3 (2017) of this *Newsletter*. The court thus vacated the district court's judgment and remanded the case for the entry of judgment in SWN and Equinor's favor. *Young*, 982 F.3d at 209.

Editor's Note: The reporter's firm represented Equinor USA Onshore Properties, Inc. in this case.

West Virginia Supreme Court of Appeals Affirms Lower Court Ruling That Base Lease Was Subject to Top Lease Even Though Base Lease Was Later Modified to Extend Primary Term

In *EQT Production Co. v. Antero Resources Corp.*, 851 S.E.2d 94 (W. Va. 2020), the West Virginia Supreme Court of Appeals affirmed a lower court decision that, under West Virginia's recording acts, a top lease had priority over a base lease, even though the base lease was later amended to extend its primary term.

On December 13, 2011, Larry W. and Linda J. Lemasters granted an oil and gas lease to PetroEdge Energy, LLC, covering a tract of land containing 15.25 acres in Tyler County, West Virginia, which provided for a five-year primary term that would expire on December 13, 2016 (the "Base Lease"). On January 12, 2012, a memorandum of the Base Lease was recorded in the Tyler County land records, but the Base Lease itself was never recorded. Neither the Base Lease nor the memorandum provided for any right of first refusal, right of renewal, or automatic option to extend the primary term. After various assignments, EQT Production Company (EQT) acquired the Base Lease. *Id.* at 95.

During the primary term of the Base Lease, the Lemasters granted a second lease, dated June 24, 2016, but not effective until December 14, 2016, to Antero Resources Corporation (Antero) (the "Top Lease"). The Top Lease provided that Antero would pay 5% of the total lease bonus at the time of execution and that the Lemasters would be paid the balance of the bonus within 15 business days of the effective date. On August 30, 2016, a memorandum of the Top Lease was recorded in the Tyler County land records. The memorandum contained the following two provisions:

> Lessor [the Lemasters] covenants and agrees that, as of the date Lessor executes this Lease, Lessor has not agreed to extend, amend, modify, or renew the Existing Lease [the Base Lease], or to take any action which would result in such extension, amendment, modification, or renewal of the Existing Lease, and Lessor further covenants and agrees that Lessor shall not enter into any such agreement or take any such action at any time after the date Lessor executes this Lease.

Id. at 96 (alterations in original) (emphasis omitted).

> Lessor and Lessee [Antero] acknowledge that the lands described in this [Top] Lease are presently subject to Oil and Gas Lease dated December 13, 2011 and set to expire on December 13, 2016 . . . (the "Existing Lease"). This [Top] Lease is granted on Lessor's reversionary interest in the leased premises and is hereby vested in interest [sic], but, as subject to the Existing Lease, the interest covered by this [Top] Lease shall vest in possession upon the termination of the Existing Lease.

Id. (alterations in original). Despite these provisions in the Top Lease, the Lemasters and EQT agreed to extend the primary term of the Base Lease by an Amendment and Ratification of

Oil and Gas Lease dated September 24, 2016, and recorded in the Tyler County land records on December 12, 2016. *Id.*

On March 16, 2017, Antero filed suit against EQT and the Lemasters in the Circuit Court of Tyler County for breach of contract, intentional interference with contractual relationship, declaratory judgment, and slander of title, and asked the court to declare that (1) the 2016 amendment and ratification of the Base Lease was invalid and ineffective, (2) the Top Lease was the only valid lease, and (3) the Base Lease was either invalid or subordinate to the Top Lease. In a counterclaim, EQT asked the court to declare that the Base Lease was the only valid lease and that the Top Lease was subject to the Base Lease, as amended and ratified by the 2016 amendment and ratification. *Id.* at 96–97.

On January 3, 2019, the court granted Antero's motion for partial summary judgment and denied EQT's cross-motion for summary judgment and held that, under the West Virginia recording acts, W. Va. Code §§ 40-1-8 and -9, the Top Lease was the valid oil and gas lease and that the Base Lease and its 2016 amendment and ratification were subject to the Top Lease. *EQT*, 851 S.E.2d at 97. EQT appealed, arguing that (1) it had the right to amend the Base Lease; (2) the Top Lease remained subject to the Base Lease, as amended, because the conditions necessary to make the Top Lease effective had not occurred; (3) the recording of the Top Lease did not render the Base Lease, as amended, subordinate; and (4) the no-modifications provision in the Top Lease is unenforceable and void as against public policy. *Id.*

The West Virginia Supreme Court of Appeals affirmed the lower court's decision, rejecting EQT's argument that it had an unlimited right to amend the Base Lease, and instead holding that the determinative issue in the case was which lease had priority, as determined under the West Virginia recording acts, which provide that "every such contract . . . conveying real estate shall be void, as to . . . subsequent purchasers for valuable consideration without notice, until and except from the time that it is duly admitted to record . . . ." *Id.* at 98 (emphasis omitted) (quoting W. Va. Code § 40-1-9). As the court noted, no one disputed that the Base Lease had not been extended by production or operations. *Id.* at 99. As a result, Antero could not have had actual or constructive notice of any right on EQT's part to extend the Base Lease other than through those two options since no other option existed at the time Antero acquired the Top Lease. On the other hand, there was deposition testimony that EQT had actual knowledge of the Top Lease prior to the execution of the 2016 amendment and ratification of the Base Lease. *Id.*

WISCONSIN – MINING

Dennis J. Donohue
– Reporter –

Wisconsin Approves New Rules for Nonferrous Metallic Mineral Mining

On January 27, 2021, the Wisconsin Natural Resources Board approved new regulations governing nonferrous metallic mineral mining in Wisconsin. The rules update existing mining regulations to, among other things, implement the repeal of Wisconsin's "prove it first" mining moratorium in 2017. The new rules substantially increase the cost of applying for mining and exploration permits, and require any proposed project to notify tribes with reservation boundaries or that have treaty rights on lands within 60 miles of the project. The rules also contain siting requirements that would prohibit mining in certain scenic or environmentally sensitive areas. The rule package is generally supported by industry groups. The rules are intended to bring Wisconsin's regulatory program more in line with similar regulations in Minnesota and Michigan. The rules are subject to approval by the Wisconsin legislature and Governor Tony Evers before they can take effect. Detailed additional information on the new rule package can be accessed at https://dnr.wisconsin.gov/topic/Mines/Metallic.html.

WYOMING – OIL & GAS

Jamie L. Jost
Amy Mowry
– Reporters –

Trial Court Has Jurisdiction over Settlement Funds Only If Deposited with the Court, but Judgment Setoffs Are Valid

The oil and gas business may be incidental to the court's rulings in *Mantle v. North Star Energy & Construction, LLC* (*Mantle III*), 2020 WY 125, 473 P.3d 279, but the case offers potentially useful procedural instruction on a party's entitlement to settlement funds and the operation of setoffs in multi-party litigation. This series of cases may be a valuable resource as companies involved in all facets of oil and gas operations face an increasingly uncertain future.

Mantle III is the third appeal to the Wyoming Supreme Court of the trial court's rulings on a lengthy and acrimonious dispute originating in Johnson County, Wyoming, between Alexander Reed Mantle and Marjorie M. Mantle, a husband and wife, and three brothers, Ray, Gary, and Matt Garland, along with their separate oil and gas services and construction companies (respectively, Hot Iron, Inc., Three Way, Inc., and MGM Enterprises, Inc.). The court issued its first opinion on the dispute on March 12, 2019, in *Mantle v. North Star Energy & Construction LLC* (*Mantle I*), 2019 WY 29, 437 P.3d 758, followed by a second opinion on May 21, 2019, in *Mantle v. North Star Energy & Construction LLC* (*Mantle II*), 2019 WY 54, 441 P.3d 841.

Understanding the court's holdings in *Mantle III* requires stepping back to *Mantle I* and the origins of the dispute. In a nutshell, trouble brewed in a market downturn and boiled over when a business deal went bad. In 2011, the Garland brothers, through their separate entities, formed North Star Energy & Construction, LLC (North Star). Alexander Mantle served as North Star's president, while accounting services for the company were provided by Karl Killmer. *Mantle I*, 2019 WY 29, ¶ 1. In 2014, Alexander Mantle and Killmer entered into a memorandum of understanding (MOU) with the Garlands setting out the terms of their agreement to purchase North Star. Over $6 million toward the purchase price was personally guaranteed by the Mantles. *Id.* ¶ 2. Meanwhile, using securities held by the Mantles and their trusts, North Star secured a $3 million loan from First Northern Bank (FNB). Before the end of 2014, as North Star continued to struggle financially from falling oil prices and "poor business practices," Alexander Mantle backed out of the deal. *Id.* ¶ 3. The Garlands regained management of North Star and began liquidating, while the Mantles negotiated a new loan from FNB to acquire the original loan to North Star, unsurprisingly leading to a tangle of litigation claims. *Id.*

The Mantles filed their original complaint with the Johnson County District Court in May 2015, naming as defendants each of the Garlands and each of their separate entities, as well as

GT Investments, Inc. (GTI) (the purchaser of certain property in Gillette, Wyoming, from North Star) and Wyodak Energy Services, LLC (Wyodak) (formed in April 2015 by Gary Garland and others, subsequently hiring former North Star employees and purchasing equipment from North Star). *Id.* ¶ 42. The Mantles alleged unjust enrichment, constructive fraud, bad faith, negligent misrepresentation, fraudulent conveyance, and alter-ego liability, and the Garlands counterclaimed alleging breach of contract (the MOU), breach of fiduciary duty, promissory estoppel, and equitable estoppel. North Star and the Garland entities joined in claims against both the Mantles and Killmer, alleging breach of contract and breach of implied contract to enforce the Mantle and Killmer guarantees; promissory estoppel; negligent misrepresentation; breach of fiduciary duty, equitable estoppel, and unclean hands against Alexander Mantle; and accountant malpractice against Killmer and Killmer & Associates, his accounting firm. *Id.* In June 2016, the Mantles amended their complaint to add claims of breach of fiduciary duty, securities violation, and actual fraud, and the defendants answered but did not refile their counterclaims. *Id.* ¶ 43. Killmer settled the claims against him and his accounting firm, which the court dismissed with prejudice. *Id.* ¶ 44. Wyodak was also dismissed from the action on their successful summary judgment motion, in December 2016. *Id.* ¶ 45. The Mantles, Gary Garland, and Raymond Garland each appealed their respective claims, and the cases were consolidated for oral argument and decision. *Id.* ¶ 50.

Mantle I frames the woeful tale of North Star's financial demise with the 11 issues presented in the appeal:

1. Did the Garlands and their associated entities abandon their counterclaims when they did not refile them after the amended complaint?
2. Was the [MOU] an enforceable contract?
3. Did the district court err when it concluded that the Garlands' negligent misrepresentation claim against Mr. Mantle would entitle them to no additional damages?
4. Did the district court err when it found no disputed issues of material fact to support Mantles' claim of actual fraud?
5. Did the district court correctly decide that certain North Star conveyances were fraudulent?
6. Are the Garlands entitled to equitable affirmative defenses?
7. Did the district court correctly conclude that the elements necessary for LLC veil-piercing were absent?
8. Did North Star's members have a fiduciary duty to its creditors?
9. Did the Garlands owe the Mantles a duty of good faith?
10. Should the Garlands' breach of fiduciary duty claim have been brought as a derivative action?
11. Did the district court abuse its discretion when it denied Mantles' attorney fees?

Id. ¶ 4.

Affirming the district court's order in all respects, the court found (1) the Garlands and their entities did not abandon their counterclaims even though they did reiterate those claims in the answer to the Mantles' amended complaint, *id.* ¶¶ 51–55; (2) the MOU was an enforceable contract, *id.* ¶¶ 56–73; (3) the Garlands had failed to establish additional damages on their negligent misrepresentation claim, *id.* ¶¶ 77–79; (4) there were no disputed issues of material fact to support the Mantles' claim of actual fraud, *id.* ¶¶ 80–85; (5) certain North Star conveyances were fraudulent, and others were not, *id.* ¶¶ 86–116; (6) equitable affirmative defenses were not available to the Garlands, *id.* ¶¶ 117–21; (7) the elements necessary for LLC veil-piercing were absent, *id.* ¶¶ 122–35; (8) North Star's members did not have a fiduciary duty to the company's creditors, *id.* ¶¶ 136–45; (9) the Garlands did not owe the Mantles a duty of good faith, *id.* ¶¶ 146–48; (10) the Garlands' breach of fiduciary duty claim should have been brought as a derivative action, *id.* ¶¶ 149–57; and (11) the district court did not abuse its discretion when it denied the Mantles' attorney fees, *id.* ¶¶ 158–59.

Mantle II dealt with the Mantles' appeal of certain post-trial issues, rephrased by the court as

1. Did the district court have subject matter jurisdiction to offset the judgments when that issue was pending in this Court in *Mantle I*?
2. With respect to the Killmer Settlement Funds:
   a. Is there a reviewable order in the record regarding whether the Garlands had standing to assert a direct claim against Mr. Killmer?
   b. Did the Mantles have a superior security interest in the Killmer Settlement Funds by operation of the "general intangibles" clause of the FNB security agreement?
3. Did the district court err when it awarded North Star's attorneys, The Kuker Group, their attorney fees from a portion of the Killmer Settlement Funds?
4. Did the district court err when it issued a *nunc pro tunc* order that removed Marjorie Mantle's name from the order that disbursed the Killmer Settlement Funds?

Mantle II, 2019 WY 54, ¶ 2.

The court concluded the district court did not have subject matter jurisdiction to offset the judgments when that issue was pending at the supreme court in *Mantle I*. *Id.* ¶ 18. The court acknowledged that while "a district court has the 'inherent power to allow or compel an equitable set-off,'" *id.* ¶ 14 (quoting *Cargill, Inc. v. Mountain Cement Co.*, 891 P.2d 57, 67 (Wyo. 1995)), that inherent authority "cannot extend to issues over which this Court has acquired jurisdiction," *id.* The court agreed with the Mantles that the offset issue appealed in *Mantle I* was no longer within the jurisdiction of the trial court, and the matter was remanded for further proceedings. *Id.* ¶ 18. The court found the question of entitlement to the Killmer settlement funds not properly presented on a Wyo. R. Civ. P. 54(b) certification, but rather than dismiss the matter remanded it along with the settlement funds question. *Id.* ¶ 24. The court further determined the FNB security agreement did not cover the Killmer settlement proceeds, affirming the district court's conclusion on that point. *Id.* ¶ 28.

As to the district court's "first come, first serve" method for the disbursement of North Star's share of the settlement funds, a portion of which was given to its dissolution attorneys, the court found the approach "not inequitable under the circumstances" and not an abuse of discretion. *Id.* ¶ 32. Finally, the court found the district court's order to remove Marjorie Mantle's name from the order that disbursed the Killmer settlement funds was not erroneous. *Id.* ¶ 34.

In *Mantle III*, the third appeal of the case, the court again affirmed the district court's conclusions on remand that a judgment against Alexander Mantle should set off judgments the Mantles had against Ray and Gary Garland, and that the Mantles were not entitled to the proceeds from a settlement of a third-party action against Killmer and his accounting firm. *Mantle III*, 2020 WY 125. The Mantles argued that the law of the case doctrine precluded Ray and Gary Garland from asserting their claims for setoff, since they allegedly abandoned their appeal in *Mantle I*. *Id.* ¶ 17. The court disagreed, pointing to exceptions to the law of the case doctrine recognized in *Lieberman v. Mossbrook*, 2009 WY 65, ¶ 28, 208 P.3d 1296 (law of the case doctrine does not apply when evidence in a subsequent proceeding is substantially different from that in an earlier proceeding) and *In re Guardianship & Conservatorship of Parkhurst*, 2010 WY 155, ¶ 15, 243 P.3d 961 (law of the case doctrine does not apply to issues left open), and concluding the district court "properly refused to apply the law of the case to bar [the Garlands'] setoff claims because their second motion for setoff was brought in a much different procedural posture than the first." *Mantle III*, 2020 WY 125, ¶ 21. The Mantles also argued the Garlands waived their rights to setoff by failing to specifically plead them as counterclaims. *Id.* ¶ 26. The court disagreed, concluding the Garlands occupied a plaintiff's position in their setoff counterclaims, and they were not required to plead a separate cause of action. *Id.* ¶ 31. As to the Mantles' claim the district court should not have used the judgment against Alexander Mantle to offset their judgments against the Garlands, the court found the district court's decision in this regard proper, because partial assignments of judgments are allowed, mutuality did exist, and equity supported the setoff. *Id.* ¶¶ 32–44.

Finally, with respect to the Killmer settlement funds in dispute, the court noted the somewhat complicated series of additional facts related to that settlement and the parties' claims to those funds, but in essence reiterated its affirmation of the district court's "first come, first serve" distribution of the settlement funds deposited with that court, and also agreed that as to any Killmer settlement funds that had not been deposited, the district court lacked subject matter jurisdiction to distribute those funds. *Id.* ¶¶ 52–62.

Failures and Choices Do Not Qualify as Force Majeure Events to Excuse Nonperformance

Denbury Onshore, LLC v. APMTG Helium LLC, 2020 WY 146, 476 P.3d 1098, centers around the question of whether a party's nonperformance under a contract is excusable under force majeure principles. The facts involved offer an interesting contrast to the recent rash of force majeure concerns in the wake of the COVID-19 pandemic's widespread disruptions of industry.

Air Products and Chemicals, Inc. (Air Products) and Matheson Tri-Gas, Inc. (Matheson), formed a joint venture, APMTG Helium LLC (APMTG), and on January 30, 2009, entered into a helium feedgas agreement (HFA-I) with Cimarex Energy Co. (Cimarex) and Riley Ridge, LLC (Riley Ridge), for the purpose of sale and delivery (by Cimarex and Riley Ridge) and purchase and receipt (by APMTG) of certain quantities of helium over the course of several years. The HFA-I required Cimarex and Riley Ridge to pay APMTG liquidated damages calculated according to a formula if they failed to deliver the required amount of helium in any given year. The liquidated damages were not to exceed $8 million per year, or for the life of the agreement the equivalent amount of APMTG's construction costs for a plant related to the venture, predicted to be between $38.6 and $42.9 million. *Id.* ¶ 3. The agreement was to last for 20 years, with delivery required to begin no later than December 1, 2011, unless a force majeure event occurred or unless the parties agreed otherwise in writing. *Id.* ¶ 4.

The HFA-I's force majeure clause (Article 17) defined "force majeure" as

> any event outside the reasonable control of a Party that could not have been avoided or overcome by that Party's exercise of reasonable care and due diligence and shall include without limitation the following: strike, lockout, concerted act of workers or other industrial disturbance; fire, explosion, flood, blizzard, extreme weather conditions or other natural catastrophe; epidemic or pandemic; civil disturbance, riot or armed conflict (whether declared or undeclared); acts of terrorism; curtailment, shortage, rationing or allocation of normal sources of supply of labor, materials, transportation, energy or utilities; accident; act of God; delay(s) or failure of performance of contractor(s) (of any tier) or vendor(s); sufferance of or voluntary compliance with act of government and government regulations and/or orders (whether or not valid); cancellation by the U.S. Bureau of Land Management, Department of the Interior, of the "Contract for Extraction and Sale of Federal Helium"; embargo; natural or mechanical supply well failure (in whole or in part) and machinery or equipment breakdown. Notwithstanding anything herein to the contrary, the following events shall not be considered Force Majeure events: the concentration of helium contained in the Helium Feedgas below that defined in Clause 9.1; and loss of markets for natural gas or Helium.

Id. ¶ 5 (emphasis omitted). The article also contained notice requirements for any occurrence thought to be a force majeure event, as well as notifications for changed circumstances and a requirement to attempt to correct the situation using "commercially reasonable investments." *Id.*

Denbury Onshore, LLC (Denbury) entered the picture in July 2010 when it purchased the minority stake of Riley Ridge in the "Riley Ridge Plant," constructed by Riley Ridge and Cimarex in conjunction with the HFA-I. In June 2011, Denbury also purchased Cimarex's interest in the plant and began running the HFA-I project. *Id.* ¶ 7. By the end of 2011 Denbury was experiencing construction delays on its plant, and delivery of the required helium was not made by the December 2011 deadline. Denbury sent notice of a force majeure event to APMTG on November 12, 2012, specifying the cause pursuant to Article 17 of the HFA-I as the failure of its plant construction contractor. APMTG rejected Denbury's claim as a force majeure event and sent Denbury an invoice for the $8 million in liquidated damages under the HFA-I. *Id.* ¶¶ 8–9.

After negotiations, Denbury agreed to pay a total of $9.1 million to APMTG to cover the first-year liquidated damages and additional operating expenses incurred by APMTG, and the parties entered into an amended and restated helium feedgas agreement (HFA-II) requiring Denbury to begin delivering helium by August 1, 2013, subject to a force majeure event or as agreed otherwise by the parties in writing. The annual liquidating damages provision in the HFA-II remained the same, with a total cap of $46 million. Additionally, the parties agreed the laws of the state of New York would govern. *Id.* ¶¶ 10–11.

Again, after failing to deliver by the August 1, 2013, date, on July 11, 2014, Denbury gave notice to APMTG of a force majeure event, this time due to the failure of several wells critical for helium production. *Id.* ¶ 16. Again, APTMG rejected the force majeure claim because the wells were within Denbury's "reasonable control" and their failure reasonably could have been avoided, in addition to Denbury's failure to provide "prompt notice" within the meaning of Article 17. *Id.* ¶ 17. Denbury delivered no helium after June 2014, and APTMG filed its complaint in the District Court of Sublette County, alleging breach of contract, unjust enrichment, and breach of the implied covenant of fair dealing. Denbury claimed its nonperformance was excused under the force majeure clause of the HFA-II, which mirrored that in the HFA-I. *Id.* ¶¶ 19–20.

Applying New York law pursuant to the HFA-II, the trial court found Denbury (now Denbury, Inc., after emerging from Chapter 11 bankruptcy on September 18, 2020) had not proven its failure to perform was excused by a valid force majeure event. *Id.* ¶ 21 (citing *Beardslee v. Inflection Energy, LLC*, 904 F. Supp. 2d 213, 220 (N.D.N.Y. 2012) (the party invoking a force majeure provision bears the burden of establishing it has been met), *aff'd*, 798 F.3d 90 (2d Cir. 2015)). Except for a period of approximately 36 days (from July 11, 2014, to mid-August 2014), the district court found Denbury had failed to meet its burden of proof, and APMTG was awarded over $35 million in liquidated damages and interest on its breach of contract claim, but the court also concluded New York law barred APMTG's unjust enrichment claim "because the parties' disputes were controlled by a contract and APMTG had failed to prove Denbury's breach of the implied covenant of good faith and fair dealing was 'not duplicative of its breach of contract claims.'" *Id.*

Denbury appealed to the Wyoming Supreme Court, who agreed with the district court's determinations and affirmed its rulings. First, the court noted that "whether the doctrines of frustration of purpose and impossibility of performance allow for termination of a contract under New York law" is unclear, *id.* ¶ 27, but even if they do, "they are not available where 'the event which prevented performance was foreseeable and provision could have been made for the event's occurrence,'" *id.* ¶ 28 (quoting *Rebell v. Trask*, 632 N.Y.S.2d 624, 627 (App. Div. 1995) (frustration of purpose); citing *Kel Kim Corp. v. Cent. Markets, Inc.*, 519 N.E.2d 295, 296 (N.Y. 1987) (impossibility)). In this case, both the HFA-1 and HFA-II recognized the possibility of both contractor and well failures, and "[b]ecause the parties 'explicitly contemplated, and provided for' the possibilit[ies] . . . , the frustration of purpose and impossibility doctrines [were] not available." *Id.* ¶ 31 (quoting *Warner v. Kaplan*, 892 N.Y.S.2d 311, 313 (App. Div. 2009)). Further, the court concluded the contractor failure and well failure events were not contemplated by the parties as grounds for termination of the HFAs under their unambiguous language. *Id.* ¶ 34.

Second, the court agreed with the district court that Denbury's assertion of contractor failure was not a force majeure event. Once the HFA-II was executed on May 23, 2013, the earlier contractor failure was essentially resolved between the parties, and Denbury could not claim that failure as a continuing event. Further, Denbury did not provide notice of any ongoing or new force majeure event between May 2013 and July 2014, as required by the HFA-II. *Id.* ¶ 37. Critically, the court pointed out that "when the parties have themselves defined the contours of force majeure in their agreement, those contours dictate the application, effect, and scope of force majeure," *id.* ¶ 40 (alteration omitted) (quoting *Constellation Energy Servs. of N.Y., Inc. v. New Water Street Corp.*, 46 N.Y.S.3d 25, 27 (App. Div. 2017)), and that the phrase "failure of performance of contractor" logically would not contemplate a party's failure, as was the case in the post-May 2013 HFA-II, *id.* ¶ 41.

Finally, as to Denbury's well failure claim, the court agreed Denbury had proven the well failure was a qualifying force majeure event between July 11, 2014, and mid-August 2014, but Denbury failed to prove that event continued beyond August 14, 2014. *Id.* ¶ 49. Denbury argued the well conditions themselves (sulfur deposition) caused the well failures and were thus the actual force majeure event, but the record revealed the force majeure event was described as certain mechanical operations and necessary equipment retrievals, not the geologic conditions of the wells themselves. *Id.* ¶ 54. Moreover, even if the geologic well conditions had been identified as the actual force majeure event, that event was limited in duration to the time specified in Denbury's notice to APMTG (between June and August 2014), not attributable to subsequent periods. *Id.* ¶ 55. The Wyoming Supreme Court deferred to the district court's judgment that the evidence presented supported its conclusion that the well conditions were within Denbury's reasonable control and could have been avoided or overcome by the exercise of reasonable care and due diligence after mid-August 2014. *Id.* ¶ 57.

This case provides useful guidance on the requirements for invoking force majeure provisions in a contract and on the limitations of those provisions. Ultimately, force majeure provisions will be narrowly construed, and foreseeability, reasonable control over operative factors, and the intentions of the parties are of critical importance in a court's interpretation of those terms.

CANADA – OIL & GAS

Matthew Cunningham
– Reporter –

Canada Takes Step Towards Implementing UNDRIP

In 2016, the Canadian federal government endorsed the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), an international instrument that provides a road map to advance reconciliation with indigenous peoples. UNDRIP's 46 articles contain collective rights constituting minimum standards necessary for the "survival, dignity and well-being of the indigenous peoples of the world." UNDRIP art. 43. The act of endorsement, however, did not commit the Canadian government to take any concrete action to implement UNDRIP.

In December 2020, the federal Minister of Justice David Lametti introduced Bill C-15, *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples*. Bill C-15 is based on a private member's bill from 2019, Bill C-262, which did not become law. Once in force, the bill would commit the Canadian government to do several things, including:

- taking all measures to ensure that the laws of Canada are consistent with UNDRIP;
- preparing and implementing an action plan to achieve UNDRIP's objectives; and
- creating an annual report on progress undertaken in respect of the above.

Note that Bill C-15 is distinct from legislation enacted in 2019 at the provincial level in British Columbia with similar aims, the *Declaration on the Rights of Indigenous Peoples Act*, S.B.C. 2019, c 44 (DRIPA). DRIPA is discussed in more depth below.

<u>The Bill</u>

Bill C-15 builds on its predecessor Bill C-262 by including provisions related to the following:

- an acknowledgement that Indigenous peoples have an inherent right to self-determination and that all relations with such peoples must be based on recognizing and implementing this right;
- an affirmation that UNDRIP is a source for the interpretation of Canadian law; and
- provisions stating that each sub-national unit—province, territory, or municipality—will have the ability to establish their own approach to contribute to the implementation of UNDRIP within the scope of their own authority.

As provinces have jurisdiction over their own natural resource development, this last point will be of particular interest to entities involved in the oil and gas sector. With Bill C-15, the federal government appears to be indicating that it will allow provinces to determine their own method of implementing UNDRIP in areas of provincial jurisdiction, something British Columbia has already begun with DRIPA.

However, as currently drafted, Bill C-15 is unclear as to any recourse the federal government may have to remedy what it may deem inadequate or inappropriate responses to implementing UNDRIP at other levels of government. The sole provision concerning this is section 5, which states that "[t]he Government of Canada must, in consultation and cooperation with Indigenous peoples, take all measures necessary to ensure that the laws of Canada are consistent with the Declaration." Although taking "all measures" may indicate that the government has many options open to it in this regard, it is not clear if the term the "laws of Canada"—an undefined term in the bill's current form—will apply only to federal UNDRIP legislation or to other levels of government as well.

An additional point of interest in the bill is the adoption of selected provisions of section 35 of the *Constitution Act, 1982*, being *Schedule B to the Canada Act, 1982*, c 11 (U.K.) (Constitution Act). In particular, Bill C-15 adopts the Constitution Act's definition of "aboriginal peoples of Canada" (section 2(1)) and contains language recognizing that existing rights are affirmed and will not be diminished in the process of implementing UNDRIP (section 2(2)). While this may assist in setting a baseline for what changes may be made pursuant to UNDRIP legislation, it may also add an additional layer of complexity to an already-complex process.

Section 6(1) of the bill also requires the Canadian government to prepare and implement an action plan to achieve UNDRIP's objectives. The provision states what measures this action plan must include in section 2, as follows:

- measures addressing injustices, prejudice, and forms of violence and discrimination, including systemic discrimination, against Indigenous peoples;
- provisions promoting mutual respect, understanding, and good relations, including via human rights education; and
- measures relating to monitoring, oversight, recourse, remedy, or other accountability measures regarding the implementation of UNDRIP.

Pursuant to section 6(4) of Bill C-15, this action plan must be prepared no later than three years after the day on which the section comes into force. Once tabled, the plan must be made publicly available. Note that the bill is currently not in force but is currently at first reading at the time of this report. In Canada, bills must undergo three readings and other hurdles, including being considered at the committee level, before becoming law. As such, there is currently no hard timeline for the preparation of Bill C-15's action plan.

Implementation

The preamble of UNDRIP notes that it is meant to be a "standard of achievement to be pursued." The instrument itself is not prescriptive as to how rights for Indigenous peoples are to be granted and protected. Given the international nature of the instrument and the variety of Indigenous peoples worldwide, this is understandable. However, guidance on how UNDRIP is to be implemented and what effects it may have on the legal landscape is lacking.

It is worth noting that in addition to DRIPA, several pieces of Canadian legislation already make reference to UNDRIP, including the *Impact Assessment Act*, S.C. 2019, c 28, s 1 (IAI) and the *Canadian Energy Regulator Act*, S.C. 2019, c 28, s 10 (CERA), both of which impact the natural resources industry. However, the existing legislation, including both the IAI and CERA, only makes reference to the federal government's commitment to implementing UNDRIP. It does not contain specific provisions relating to the instrument itself or how its aims are to be implemented. Accordingly, there is little precedent in Canadian legislation for the task of implementing UNDRIP's objectives.

DRIPA and Bill C-15

As noted above, DRIPA is provincial legislation meant to affirm the application of UNDRIP to the laws of British Columbia, as well as contribute to its implementation. It shares some similarities with Bill C-15, including definitions drawn from the Constitution Act (section 1) and requirements for an action plan (section 4) and an annual report (section 5). Further, other provisions, such as the purpose clause and a requirement to align provincial laws with UNDRIP, are also present in the bill.

However, unlike Bill C-15, DRIPA provides the British Columbian government with the ability to make decision-making agreements with Indigenous governing bodies (section 7). This provision allows the provincial government to make agreements with such governing bodies regarding the exercise of statutory decision-making power jointly as between the government and the Indigenous governing body, as well as providing for the consent of the Indigenous governing body to the exercise of a statutory power of decision making. DRIPA contains a definition in section 1(1) of "Indigenous governing body" as "an entity that is authorized to act on behalf of Indigenous peoples that hold rights recognized and affirmed by section 35 of the *Constitution Act, 1982*." Given that project proponents have had issues negotiating with the correct Indigenous governing body in the past and the existing tensions between band councils and traditional ruling structures, this definition is an important one. It remains to be seen whether Bill C-15 will adopt this language in its later stages.

In essence, these agreements appear to be a collaborative tool for the provincial government to work with Indigenous groups on decisions that may impact them. DRIPA does not prescribe the form such agreements will take, nor the substance. However, section 7(4) notes that these agreements must be published and will not be effective until such date. As of the time of this report, no such agreements have been published. As this is the case, DRIPA does not provide much guidance for the bill.

Natural Resources and Bill C-15

Going forward, the implications of Bill C-15 on the natural resources sector in Canada remain unclear. How UNDRIP will affect new and existing legislation, what input Indigenous groups may have in the process, how UNDRIP will interact with the existing Indigenous rights framework in Canada, and what remedies the various levels of government may have against one another in relation to such implementation all remain live issues. Until the bill gains more clarity as it progress through the legislative process and further details emerge regarding how UNDRIP will be incorporated into Canadian law, these issues will likely remain unresolved.

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