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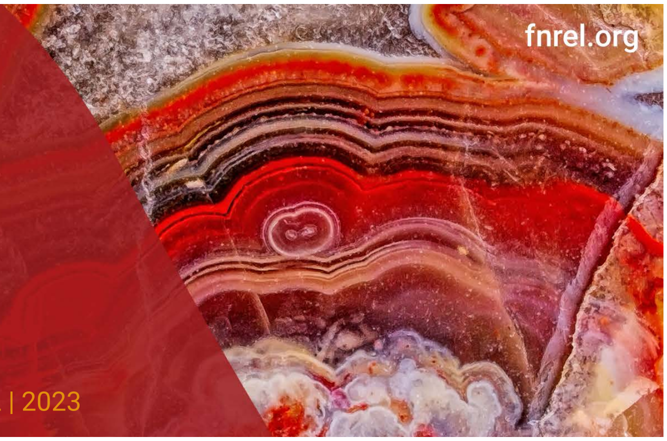

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FEDERAL — MINING

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

Alaskan Tribes Sue to Stop Donlin Gold Project

Three tribes in the Kuskokwim River region of Alaska filed a lawsuit in the U.S. District Court for the District of Alaska on April 5, 2023, challenging the federal approval of permits required for the development of the Donlin Gold Mine. *See* Complaint for Declaratory and Injunctive Relief, *Orutsararmiut Native Council v. U.S. Army Corps of Eng'rs*, No. 3:23-cv-00071 (D. Alaska Apr. 5, 2023). Earthjustice filed the complaint against the U.S. Army Corps of Engineers (USACE), the Bureau of Land Management (BLM), and the U.S. Department of the Interior on behalf of Orutsararmiut Native Council in Bethel, Tuluksak Native Community, and the Organized Village of Kwetluk, alleging three fundamental flaws with the environmental impact statement (EIS).

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FEDERAL — OIL & GAS

Kathleen C. Schroder, Reporter

Tenth Circuit Finds BLM Did Not Adequately Analyze GHG Emissions When Approving Drilling Permits

In *Diné Citizens Against Ruining Our Environment v. Haaland*, 59 F.4th 1016 (10th Cir. 2023), the U.S. Court of Appeals for the Tenth Circuit held that the Bureau of Land Management (BLM) did not adequately analyze emissions of greenhouse gases (GHG) and hazardous air pollutants (HAPs) as required by the National Environmental Policy Act (NEPA) when approving applications for permits to drill (APDs).

A coalition of citizen groups had challenged BLM's environmental analysis that considered the impacts of 370 APDs in New Mexico's San Juan Basin. *Id.* at 1024. The district court had affirmed BLM's decision. *Diné Citizens Against Ruining Our Environment v. Bernhardt*, No. 1:19-cv-00703, 2021 WL 3370899 (D.N.M. Aug. 3, 2021); *see* Vol. XXXVIII, No. 3 (2021) of this *Newsletter*.

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RENEWABLE ENERGY

Mark D. Detsky & Matthew Nadel, Reporters

FERC Rejects SPP's Proposal to Allow Transmission Owners to Conditionally Invest in Network Upgrades Associated with Interconnection of Independent Generation

On September 30, 2022, Southwest Power Pool, Inc. (SPP), the regional transmission organization for much of the Midwest, submitted proposed revisions to Attachment V (Generator Interconnection Procedures or "GIP") of its Open Access Transmission Tariff (OATT) to the Federal Energy Regulatory Commission (FERC). The tariff revisions asked FERC to allow transmission owners to elect to self-fund network upgrades identified in studies for generation additions to the transmission system, and to be able to recover the costs of those upgrades with a return on capital from interconnecting generators, i.e., "interconnection customers."

For a brief background, in 1996 FERC issued Order No. 888, 75 FERC ¶ 61,080 (Apr. 24, 1996), which requires transmission owners to provide open access transmis-

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FEDERAL — MINING

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First, the complaint alleges that the EIS did not sufficiently analyze the potential environmental impacts of a tailings dam failure by only considering the impacts of a spill of 0.5% of the tailings capacity, arguing that a tailings spill of more than 0.5% is "reasonably foreseeable" and therefore requires analysis pursuant to the National Environmental Policy Act. *Id.* at 23. Moreover, the complaint alleges that the EIS failed to assess the foreseeable impacts of such a tailings spill on the subsistence uses of the Alaskan tribes in violation of section 810 of the Alaska National Interest Lands Conservation Act. *Id.* at 25. Second, the plaintiffs argue that the EIS did not adequately disclose or respond to the findings of the human health impact assessment completed by the State of Alaska. *Id.* at 26. Finally, the complaint alleges that the joint record of decision issued by the BLM and USACE erroneously authorizes a Clean Water Act § 404 permit with a finding of no significant degradation, despite the EIS analysis determining that potential negative impacts to the Kuskokwim River rainbow smelt exist due to propeller wash from the increased barge traffic. *Id.* at 27.

The lawsuit seeks to overturn these federal authorizations, putting a halt to the mine development and requiring the federal agencies to revisit their analysis and fix these alleged deficiencies.

Rosemont and Other Mining Claim-Related Litigation Update

<u>Thacker Pass</u>

In September 2019, Lithium Nevada submitted to the Bureau of Land Management (BLM) two plans of operation—one for exploration and one for mining and reclamation—for a proposed lithium mine near Thacker Pass, Nevada. After conducting an analysis under the National Environmental Policy Act (NEPA), the BLM issued a record of decision (ROD) approving both plans. Several groups of plaintiffs filed separate cases that were consolidated. *See Bartell Ranch LLC v. McCullough*, No. 3:21-cv-00080 (D. Nev. filed Feb. 11, 2021); *W. Watersheds Project v. BLM*, No. 3:21-cv-00103 (D. Nev. filed Feb. 26, 2021).

On February 6, 2023, the court granted in part and denied in part, the plaintiffs' motions for summary judgment. *Bartell Ranch LLC v. McCullough*, No. 3:21-cv-00080, 2023 WL 1782343 (D. Nev. Feb. 6, 2023), *appeals docketed*, Nos. 23-15259, 23-15261, 23-15262 (9th Cir. Feb. 24, 2023). The court held that the U.S. Court of Appeals for the Ninth Circuit's decision regarding the Rosemont copper mine in *Center for Biological Diversity v. U.S. Fish & Wildlife Service* (*Rosemont*), 33 F.4th 1202 (9th Cir. 2022) applies, *see* Vol. 39, No. 3 (2022) of this *Newsletter*, meaning that the BLM was required, but failed, to determine whether Lithium Nevada has valid rights under the Mining Law of 1872 (Mining Law) to occupy the approximately 1,300 acres planned for use as waste rock dumps and tailings piles outside the mine pit.

The court recognized that while the *Rosemont* decision involved U.S. Forest Service land and the Thacker Pass case involves BLM land, "the language of the regulations at issue in *Rosemont* is so similar to the language of the regulations at issue here, and the reasoning of *Rosemont* otherwise so applicable to these facts, that the Court finds *Rosemont* controlling." *Bartell Ranch*, 2023 WL 1782343, at *4. The court explained that in approving the copper mine at issue in *Rosemont*, the Forest Service "either assumed that Rosemont's mining claims on that land were valid or (what amounted to the same thing) did not inquire into the validity of the claims." *Id.* (quoting *Rosemont*, 33 F.4th at 1212). Based on the assumption the mining claims were valid, the Forest Service concluded Rosemont's permanent occupation of the claims with its waste rock was permitted under the Mining Law. *Id.* The *Rosemont* court held that the Forest Service erred because the Mining Law did not give Rosemont the right to dump its waste rock on Forest Service land on which it had no valid mining claims. *Id.* The *Rosemont* court also rejected the Forest Service's argument that the National Forest Management Act (NFMA) and implementing regulations did not require it to determine whether a project proponent had discovered valuable minerals on land it planned to occupy with waste dumps and tailings piles before approving those uses. *Id.* The NFMA and its related regulations did not apply because both refer back to the Mining Law. *Id.* In other words, only the Mining Law could permit a project proponent to dump waste rock on its mining claims, and only if those claims were valid. *Id.*

Similarly, the Thacker Pass court held that the relevant section of the Federal Land Policy and Management Act (FLPMA), 43 U.S.C. § 1732(b), refers back to the Mining Law, and this section of FLPMA requires the BLM to look to section 22 of the Mining Law and determine claim validity before authorizing a project proponent to occupy non-millsite lands outside a mine pit with waste dumps and tailings piles. *Bartell Ranch*, 2023 WL 1782343, at *5.

For similar reasons, the court also rejected the BLM's argument that its surface management regulations at 43 C.F.R. subpt. 3809 and the *BLM Handbook* interpreting those regulations do not require any determination from the BLM as to whether Lithium Nevada located any valuable mineral deposits under the waste dump land. The court held that the decision in *Rosemont* was controlling because, as with FLPMA, both refer back to the Mining Law. *Id.* at *6. The purpose of those regulations is to "[p]revent unnecessary or undue degradation of public lands by operations authorized by the mining laws." *Id.* (alteration in original) (quoting 43 C.F.R. § 3809.1(a)). The BLM surface use provisions are all within the subpart titled, "Part 3800—Mining Claims Under the General Mining Laws." *Id.* The relevant portion of the *BLM Handbook* on which the BLM relied includes the caveat: "[p]rovided the subject land is open to entry under the Mining Laws." *Id.* (alteration in original). Thus, the court reasoned, those BLM surface use regulations refer back to the Mining Law, just like the Forest Service regulations discussed in the *Rosemont* decision. *Id.* Therefore, "*Rosemont* makes clear that the approving federal agency must evaluate the mining project proponent's rights under lands they intend to use for waste dumps before they approve the use of that land for that purpose." *Id.* It was undisputed that the BLM did not do so before issuing the ROD approving the Thacker Pass project. *Id.* at *7. Finally, the court clarified that it did not read the *Rosemont* decision as extending beyond land a mining project proponent intends to cover with waste rock and mine tailings (such as production wells, water lines, or power transmission lines). *Id.*

The court denied all of the plaintiffs' remaining claims that alleged violations of NEPA, FLPMA, and the National Historic Preservation Act. The court remanded but did not vacate the Thacker Pass decision. In doing so, the court agreed with the federal defendants' argument distinguishing the *Rosemont* decision. In the *Rosemont* case there was no evidence that valuable minerals had been found on Rosemont's mining claims covering the waste dump land. However, for Lithium Nevada's project, the administrative record contained evidence of lithium mineralization throughout the project area, including the area under which the company planned for its waste rock pile. Therefore, the court found there was at least a serious possibility the agency would be able to substantiate its decision on remand. *Id.* at *24.

The plaintiffs sought, and the district court denied, motions for injunction pending appeal. On March 1, 2023, the Ninth Circuit denied the plaintiffs' emergency motions for injunctive relief pending appeal. Briefing on emergency motions for preliminary injunction is underway and oral argument is scheduled for June 26, 2023.

<u>Mount Hope</u>

The Mount Hope molybdenum project is a proposed mine from Eureka Moly, LLC (Eureka Moly), located near Eureka, Nevada. In 2013, groups successfully challenged the BLM's approval of the project, and a Nevada court held the BLM's decision violated NEPA and FLPMA and vacated and remanded the decision. On remand, the BLM approved the project a second time in 2019. Some of the same plaintiffs challenged the BLM's approval, again alleging violations of NEPA and FLPMA. The plaintiffs also claimed that the BLM failed to protect lands withdrawn under Public Water Reserve 107 (PWR 107). On March 31, 2023, the court granted in part and denied in part the parties' cross-motions for summary judgment, and vacated and remanded the ROD. *Great Basin Res. Watch v. DOI*, No. 3:19-cv-00661 (D. Nev. Mar. 31, 2023).

The plaintiffs claimed the BLM failed to adequately protect federal water reserves located within the project area, in violation of PWR 107. PWR 107 was created by executive order in 1926, based on authority under the Pickett Act. PWR 107 withdrew lands containing springs or water holes, but left them open to exploration, discovery, occupation, and purchase for metalliferous minerals as permitted by the mining laws. The plaintiffs alleged the BLM violated PWR 107 by failing to adequately protect springs and surrounding lands because it approved Eureka Moly's proposal to permanently dump waste rock on the land even though the company does not have a valid mining claim for those lands, which also do not contain metalliferous minerals. The court granted the plaintiffs' motion for summary judgment on this claim. In doing so, it rejected the BLM's argument that the Pickett Act's exception that withdrawn lands remain open for exploration and occupation for metalliferous minerals as permitted by the Mining Law applies, and that Eureka Moly has a statutory right under the Mining Law to occupy and use open lands for its waste rock and tailings facilities. The court held that the Ninth Circuit's decision in the *Rosemont* case applied, explaining that the right of occupation depends on valuable minerals being found on the land in question: "If no valuable minerals have been found on the land, Section 22 [of the Mining Law] gives no right of occupation beyond the temporary occupation inherent in exploration." *Great Basin*, No. 3:19-cv-00661, slip op. at 6 (quoting *Rosemont*, 33 F.4th at 1219). As in the Thacker Pass case, the court rejected the BLM's attempt to distinguish the *Rosemont* decision on the basis that it involved Forest Service regulations as opposed to the BLM's regulations here. The court remanded to the BLM to analyze and disclose whether the lands proposed for the waste rock dump areas are valid mining claims. The court rejected the

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.

plaintiffs' remaining claims alleging violations of NEPA and FLPMA. No appeals have been filed.

Earthworks

In the *Earthworks* litigation, the appellant environmental groups recently filed their opening brief in the U.S. Court of Appeals for the D.C. Circuit. *See* Earthworks' Initial Opening Brief, *Earthworks v. DOI*, No. 20-5382 (D.C. Cir. Apr. 6, 2023), 2023 WL 2823966. The litigation began in 2009, when groups sued to block implementation of the 2003 rule that eliminated limitations on the number and acreage of allowable mill sites for each mine site. *See* Locating, Recording, and Maintaining Mining Claims or Sites, 68 Fed. Reg. 61,046 (Oct. 24, 2003) (to be codified at 43 C.F.R. pts. 3710, 3730, 3810–3850). They also challenged a 2008 rule that eliminated surface use fees on public lands for mining operators, other than processing, location, and maintenance assessments. *See* Mining Claims Under the General Mining Laws, 73 Fed. Reg. 73,789 (Dec. 4, 2008) (to be codified at 43 C.F.R. pt. 3800). In 2020, the U.S. District Court for the District of Columbia granted summary judgment for the federal defendants, *Earthworks v. DOI*, 496 F. Supp. 3d 472 (D.D.C. 2020); *see* Vol. XXXVII, No. 4 (2020) of this *Newsletter*, and the plaintiffs appealed.

In the D.C. Circuit brief, the groups argue that the 2003 rule "illegally reversed and overturned" the U.S. Department of the Interior's (DOI) previous interpretation of the millsite provision of the 1872 Mining Law. Opening Brief, 2023 WL 2823966, at *21. Previously, the DOI had interpreted the Mining Law to say that a millsite claimant was limited to claiming up to five acres of nonmineral land for millsite use in association with each valid mining claim. *Id.* at *22. The groups claim that the 2003 rule gives claimants illegal statutory rights to make as many millsite claims and acres as needed for mining operations, regardless of the number of mining claims at the site, and argued this was contrary to congressional intent under the Mining Law because Congress would not have limited the size of each millsite without also limiting the number of millsites. *Id.* The groups allege this interpretation also violates FLPMA, arguing the rule created statutory rights to the use and occupation, and potential patenting of public lands. *Id.* The groups also allege that the DOI violated NEPA by failing to conduct proper analysis in promulgating the rule. *Id.*

Briefing in the D.C. Circuit continues through September 2023. Oral argument has not yet been scheduled.

FEDERAL — OIL & GAS

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Initially, the court declined to review 161 APDs that BLM had not yet approved, finding that the plaintiffs' challenge was not ripe. *Diné Citizens*, 59 F.4th at 1028. With respect to the approved APDs, the court found two deficiencies in BLM's NEPA analysis of GHG emissions. First, the court held that BLM's analysis improperly considered direct GHG emissions from operating the wells on an annual basis, rather than over the wells' 20-year lifetime. *Id.* at 1035. The court rejected BLM's contention that it limited the estimate for direct emissions to annual emissions because "it could not estimate the lifespan or the decline curve of emissions from the wells." *Id.* at 1037. The court observed, by contrast, that BLM had estimated downstream emissions over the wells' 20-year lifetime. *Id.* In light of BLM's treatment of downstream emissions, the court found BLM's justification for examining annual direct emissions to be unreasonable and the analysis to be arbitrary and capricious. *Id.*

Second, the court found BLM's analysis of cumulative GHG emissions inadequate. BLM had compared GHG emissions from the APDs to regional, national, and global GHG emissions and concluded that the APDs would have a de minimis impact on cumulative GHG emissions. *Id.* at 1039, 1041–42. The court, however, found this analysis "does not meaningfully inform the public or decisionmakers about the impact of the emissions" because "all agency actions causing an increase in GHG emissions will appear de minimis when compared to the regional, national, and global numbers." *Id.* at 1043–44. Further, the court observed that the plaintiffs had encouraged BLM to utilize the "carbon budget method" of analysis, which involves comparing APD emissions to the carbon budget used to determine the GHG emissions that may occur without exceeding acceptable levels of global warming. *Id.* at 1043. The court found that, although NEPA does not obligate BLM to use a particular methodology to analyze impacts from its action, BLM acted arbitrarily by failing to utilize an available and more precise method of analyzing cumulative GHG impacts. *Id.* at 1044.

Additionally, the court found BLM's analysis of cumulative impacts from HAPs to be deficient. *See id.* at 1047. BLM had concluded that HAP emissions would increase only in the short term and would not result in long-term exposure. *Id.* The court, however, explained that BLM failed to consider cumulative HAP emissions from the development of 3,000 wells drilled over several years, which could result in long-term exposure to residents in the area. *Id.* Accordingly, the court concluded that BLM's analysis was arbitrary and capricious.

Notably, the court upheld other elements of BLM's NEPA analysis, including BLM's method for calculating the warming potential of methane, *id.* at 1037–39, and BLM's analysis of impacts to water resources and criteria pollutants, *id.* at 1044–46.

Having concluded that BLM's NEPA analysis was deficient, the court addressed the question of remedy. The court rejected the plaintiffs' argument that "the only appropriate remedy for an [Administrative Procedure Act] violation is vacatur." *Id.* at 1049. Rather, the court adopted the test for determining whether vacatur is appropriate set forth by the U.S. Court of Appeals for the D.C. Circuit in *Allied-Signal, Inc. v. U.S. Nuclear Regulatory Commission*, 988 F.2d 146, 153 (D.C. Cir. 1993). The court then remanded to the district court to apply the *Allied-Signal* factors to determine whether to vacate approved APDs and, if it determines vacatur is not warranted, to apply the test for injunctive relief to determine whether to enjoin development of the APDs. *Diné Citizens*, 59 F.4th at 1050.

BLM Ordered to Resume Quarterly Lease Sales in North Dakota

In *North Dakota v. U.S. Department of the Interior*, No. 1:21-cv-00148, slip op. (D.N.D. Mar. 27, 2023), the U.S. District Court for the District of North Dakota issued a preliminary injunction enjoining the U.S. Department of the Interior and the Bureau of Land Management (BLM) (collectively, Federal Defendants) from pausing quarterly oil and gas lease sales in North Dakota.

The case arose from Executive Order No. 14,008, "Tackling the Climate Crisis at Home and Abroad," 86 Fed. Reg. 7619 (Jan. 27, 2021), and particularly its direction that "the Secretary of the Interior shall pause new oil and natural gas leases on public lands." *North Dakota*, slip op. at 3 (emphasis omitted) (quoting Exec. Order No. 14,008 § 208). North Dakota challenged the Federal Defendants' decisions to cancel or postpone quarterly sales between March 2021 and early 2023, except for a lease sale held in June 2023. *See id.* at 9–26. Applying the standard for a preliminary injunction, the court first held that the

Federal Defendants' postponement or cancellation of lease sales likely violated the Mineral Leasing Act (MLA) and, second, that the postponed or canceled lease sales likely constituted an unlawful withdrawal under the Federal Land Policy and Management Act (FLPMA).

With respect to the MLA violation, the court first rejected the Federal Defendants' argument that the Secretary of the Interior has discretion to postpone or cancel lease sales. *Id.* at 29–33. To do so, the court reconciled 30 U.S.C. § 226(a), which contains discretionary language that "[a]ll lands subject to disposition under [the MLA] which are known or believed to contain oil or gas deposits *may* be leased by the Secretary" (emphasis added), with 30 U.S.C. § 226(b)(1)(A), which mandates that "[l]ease sales *shall* be held for each State where eligible lands are available at least quarterly" (emphasis added). *North Dakota*, slip op. at 29–33. Reading these sections together, the court concluded that "the Federal Defendants have mandatory duties with deadlines: they must make preparations, analyze, and make determinations regarding whether nominated lands in each state are 'eligible' and 'available' for leasing in time for the related quarterly sale deadlines." *Id.* at 31–32.

Then, the court examined each postponed or canceled lease sale and the Federal Defendants' reasons for the postponement or cancellation. *See id.* at 39–56. Although the Federal Defendants cited a slightly different reason for postponing or canceling each lease sale, *see id.*, the Federal Defendants generally maintained that they could not hold scheduled lease sales because lands were not "available" for lease, *see id.* Lands are "available" when they are "open to leasing . . . and when all statutory requirements and reviews have been met, including compliance with [NEPA]." *Id.* at 36 (alteration in original) (quoting *BLM Manual* MS-3120, Competitive Leases, subd. .11 (Rel. 3-337, Feb. 18, 2013)).

The Federal Defendants maintained that, generally, lands were not "available" for lease because BLM had not prepared environmental analyses sufficient to comply with NEPA. *See id.* at 39–56. The court, however, found that the Federal Defendants' perceived deficiencies in the NEPA analyses did not excuse the failure to hold lease sales. Citing its interpretation of the MLA, the court found that the Federal Defendants "failed to plan for and timely complete the necessary analyses for determining whether eligible lands were 'available' on a quarterly basis." *Id.* at 39; *accord id.* at 56, 59.

With respect to the FLPMA violation, the court determined that the postponed or canceled lease sales constituted a de facto withdrawal. *See id.* at 64 (citing 43 U.S.C. § 1714). FLPMA allows the Federal Defendants to "withdraw" lands from entry under the general land laws, including the MLA, by following certain procedures, including notification to Congress. *Id.* at 64–65 (citing 43 U.S.C. §§ 1702, 1714). The court observed that "the Secretary held-up thousands of acres' analyses due to a discretionary 'policy' not to plan and timely complete parcels' analyses for leasing for a year-and-a-half, and then again for at least another two quarters." *Id.* at 67. Although the court declined to draw a "bright line for when a withdrawal occurs," *id.* at 66, it determined that North Dakota was likely to establish that a de facto withdrawal had occurred without following the requisite procedures, *id.* at 68.

After finding that North Dakota met the remaining preliminary injunction factors, *id.* at 68–78, the court enjoined the Federal Defendants from imposing their "unlawful policy to disregard their statutory duty to appropriately plan for and complete their determination of whether nominated land was 'available' and 'eligible' on a timely, quarterly basis." *Id.* at 80. The court then ordered the Federal Defendants to: (1) "[a]nalyze individual parcels nominated for lease sales in North Dakota according to their statutory requirements"; (2) [m]ake lawful determinations regarding the nominated parcels' availability and eligibility"; (3) "[c]omplete those determinations in time for quarterly lease sales, as set forth in statute and regulations"; and (4) "[w]hen there are 'available' and 'eligible' lands, hold a lease sale in that quarter." *Id.* at 80–81.

At the time of this report, the Federal Defendants had not filed a notice of appeal of the decision.

ONRR Improperly Declined to Allow Deduction of NGL Transportation Fees

In *Ovintiv USA, Inc. v. Haaland*, No. 1:21-cv-02552, 2023 WL 2708821 (D.D.C. Mar. 30, 2023), the U.S. District Court for the District of Columbia reversed and remanded a decision of the Office of Natural Resources Revenue (ONRR) Director that held transportation shortfall fees for natural gas liquids (NGLs) were not deductible transportation costs.

Ovintiv USA, Inc.'s (Ovintiv), midstream agreement had provided that Ovintiv would deliver, and the midstream provider would purchase, volumes of NGLs from different sources of production. *Id.* at *4–5. The midstream provider charged a deficiency fee if Ovintiv did not supply certain specified volumes of NGLs from a certain source of production. *Id.* at *5–6. The deficiency fee was comprised of a "transportation shortfall fee" and a "fixed fee for fractionation." *Id.* The agreement also allowed Ovintiv to elect to supply additional volumes ("future elected capacity") but imposed a fee if Ovintiv did not supply these volumes. *Id.* at *5.

The controversy began when Ovintiv requested ONRR approval of a transportation allowance that exceeded 50% of the value of NGLs, in accordance with 30 C.F.R. § 1206.156(c). *Ovintiv*, 2023 WL 2708821, at *2. Ovintiv had sought to deduct the transportation shortfall fee, asserting that the fee was either a deductible firm demand charge or a capacity reservation fee under 30 C.F.R. § 1206.157(f)(1). *Ovintiv*, 2023 WL 2708821, at *6. ONRR denied the request, and the ONRR Director affirmed the decision upon Ovintiv's appeal. *Id.* Ovintiv appealed the ONRR Director's decision to the Interior Board of Land Appeals (IBLA), which did not issue a decision ahead of its statutory deadline to do so. *Id.* at *9. ONRR then appealed to federal district court, which reviewed the ONRR Director's decision as the final agency action. *See id.*

Initially, the court declined to review the ONRR Director's decision with deference under *Auer v. Robbins*, 519 U.S. 452 (1997). *Ovintiv*, 2023 WL 2708821, at *11–13. The court explained that, although an agency's interpretation of its own regulation receives *Auer* deference, an agency's application of its regulation is reviewed only for reasoned decision making. *Id.* at *11.

The court then rejected the ONRR Director's determination that the transportation shortfall fee was not deductible. The ONRR Director had concluded the fee was not deductible because it was not paid to reserve pipeline capacity and instead was a penalty. *Id.* at *7 (citing *Indep. Petroleum Ass'n of Am. v. DeWitt*, 279 F.3d 1036, 1042 (D.C. Cir. 2002)). With respect to the conclusion that the fee was not paid to reserve pipeline capacity, the court found it arbitrary and capricious for three reasons. First, the court found that the ONRR Director failed to reasonably explain the difference between the transportation shortfall fee and the fee associated with the failure to deliver the future elected capacity, which was deductible. *Id.* at *13–15.

Second, the court found that the ONRR Director did not distinguish the transportation shortfall fee from a fee held to be deductible in a prior ONRR Director's decision, *Maxus Energy Corp.*, ONRR-11-0035-OCS (June 27, 2013). *Ovintiv*, 2023 WL 2708821, at *15–16. The court observed that, with respect to both the transportation shortfall fee and the fee at issue in *Maxus*, "the shipper only pays a charge on unshipped volumes if it fails to meet the minimum threshold." *Id.* at *15. Third, the court found that the ONRR Director failed to address whether "take or pay" language in the midstream agreement should be interpreted as reserving pipeline capacity. *Id.* at *16.

Additionally, the court rejected the ONRR Director's conclusion that the transportation shortfall fee was a penalty. *See id.* at *16–17. The court explained that the ONRR Director never found that the fee was one of two nondeductible penalties identified by regulation. *See id.* at *17 (citing 30 C.F.R. § 1206.157(g)(3)). The court also observed that the ONRR Director did not distinguish the fee from those fees associated with the failure of shippers to meet volume commitments. *Id.* (citing *Maxus*).

The court then vacated the ONRR Director's decision and remanded to the IBLA for further proceedings. At the time of this report, the IBLA had not acted on the remand.

Court of Claims Rejects Claims That the United States Breached a Federal Oil and Gas Lease

In *Petro Mex, LLC v. United States*, 164 Fed. Cl. 476 (2023), *appeal docketed*, No. 23-1848 (Fed. Cir. May 4, 2023), the U.S. Court of Federal Claims issued a voluminous opinion rejecting a lessee's claim that the United States breached a federal oil and gas lease and the lessee's request for $5 million in damages.

The plaintiff had alleged that the United States, through the Bureau of Land Management (BLM), had "breached its duty to allow Petro Mex to extract, remove and sell oil and natural gas" from the contested lease. *Id.* at 527. BLM had ordered the plaintiff to shut in wells on the lease because of leaks identified during an inspection. *Id.* at 492–93. BLM then sent a notice to the plaintiff advising that, because compressors had been removed from the lease, the lease was no longer capable of production in paying quantities and would terminate unless reworking operations were commenced in 60 days. *Id.* at 500. BLM later sent the plaintiff a notice that the lease had terminated. *Id.* at 506–07. The plaintiff appealed the termination decision to the Interior Board of Land Appeals (IBLA). *Id.* at 507. On September 27, 2010, the IBLA found that BLM incorrectly determined that the lease terminated and remanded the termination decision back to BLM. *See Petro Mex, LLC*, 180 IBLA 94, 105, GFS(O&G) 9(2010). Before the Court of Federal Claims, the plaintiff alleged that BLM's shut-in order and subsequent termination notice breached the lease. *Petro Mex*, 164 Fed. Cl. at 526.

Following a trial, the court issued an opinion that set forth detailed findings of fact and law, which can be distilled to three salient holdings. The court first held that the plaintiff's claims were barred by the six-year statute of limitations in 28 U.S.C. § 2501 to bring a claim in the Court of Federal Claims. *Petro Mex*, 164 Fed. Cl. at 525–26. The court found that the plaintiff was on notice of its claims more than six years before it initiated the action. *Id.*

Next, the court held that, even if the plaintiff's claims were not time-barred, the plaintiff had not established that the United States breached the lease. The court found that BLM afforded the plaintiff "reasonable allowances" to resolve numerous issues associated with the lease, which included both major and minor violations of the lease terms and BLM's regulatory requirements. *Id.* at 550.

Finally, even though the court held that the plaintiff's claims were time-barred and the plaintiff did not establish that the United States breached the lease, the court further held that the plaintiff itself had breached the lease and that this prior breach excused any subsequent breach by the United States. *Id.* at 563. The court found that the plaintiff conceded that it had breached the lease by failing to report and pay royalties on production and an associated civil penalty. *Id.*

Breach of contract cases brought by federal lessees against the United States are relatively rare. Although the holding of the case is somewhat limited to its facts, it nonetheless adds to the small body case law related to breach of federal oil and gas leases.

Inflation Reduction Act Moots Offshore Leasing Controversy

In *Friends of the Earth v. Haaland*, No. 22-5036 (D.C. Cir. Apr. 28, 2023), *vacating* 583 F. Supp. 3d 113 (D.D.C. 2022), the U.S. Court of Appeals for the D.C. Circuit held that the Inflation Reduction Act of 2022 (IRA), Pub. L. No. 117-169, 136 Stat. 1818, mooted a controversy over offshore leases sold in the Gulf of Mexico (Lease Sale 257). The Bureau of Ocean and Energy Management (BOEM) had auctioned the leases but not issued them. Environmental nongovernmental organizations challenged the sale, and the U.S. District Court for the District of Columbia vacated the record of decision for the lease sale. *See* Vol. 39, No. 1 (2022) of this *Newsletter*. The decision was appealed.

In the IRA, however, Congress directed BOEM to issue the leases to the high bidders at the prior auction. *Friends of the Earth*, 2023 WL 3144203, at *1 (citing IRA § 50264(b)). The court of appeals concluded that the IRA mooted the appeal because "it is 'impossible' for [the] court 'to grant the prevailing party effective relief.'" *Id.* (quoting *Burlington N. R.R. Co. v. Surface Transp. Bd.*, 75 F.3d 685, 688 (D.C. Cir. 1996)). Accordingly, the court vacated the district court's decision and remanded with instruction to dismiss the case as moot. *Id.* at *2.

Alaskan Willow Project Allowed to Proceed Pending Judicial Review

In *Sovereign Iñupiat for a Living Arctic v. BLM*, No. 3:23-cv-00058, 2023 WL 2759864 (D. Alaska Apr. 3, 2023), *appeal docketed*, No. 23-35226 (9th Cir. Apr. 4, 2023), the U.S. District Court for the District of Alaska declined to preliminarily enjoin the Bureau of Land Management's (BLM) decision to approve ConocoPhillips Alaska, Inc.'s (ConocoPhillips), Willow Master Development Plan (Willow Project) in Alaska's National Petroleum Reserve. BLM had approved the Willow Project after completing a supplemental environmental impact statement prepared in response to a 2021 judicial decision vacating BLM's prior approval of the Willow Project. *Id.* at *3 (citing *Sovereign Iñupiat for a Living Arctic v. BLM*, 555 F. Supp. 3d 739, 805 (D. Alaska 2021)). A coalition of citizens group challenged BLM's approval and sought to preliminarily enjoin planned construction activities during the pendency of the litigation. *See id.* at *2.

The court determined that the plaintiffs would not be irreparably harmed by planned activities associated with the Willow Project. *See id.* at *6–11. Particularly, the court found that the harms alleged by the plaintiffs from the planned construction activities were not likely or irreparable. Additionally, the court, citing the economic interests in the Willow Project and state and federal legislative support for the Project, determined that the balance of the equities and the public interests tip “sharply against” preliminary relief. *Id.* at *15. Accordingly, the court denied the preliminary injunction without reaching the merits of the plaintiffs’ claims.

On April 4, 2023, the plaintiffs appealed the decision to the U.S. Court of Appeals for the Ninth Circuit. At the time of this report, the court of appeals had not issued a decision.

RENEWABLE ENERGY

(continued from page 1)

sion service to other entities on a comparable basis to the transmission service they provide for themselves. One of FERC’s goals in issuing Order No. 888 was to remove impediments to competition in the wholesale bulk power market and bring more efficient, lower-cost power to customers. *Id.* at P 61. Order No. 888 also encouraged utilities to band together and create independent system operators or regional transmission organizations (RTOs). *Id.* at P 106. Order No. 888 also required transmission owners to establish standardized OATTs that would apply to entities transmitting power across their lines and to entities interconnecting to the grid at any point on their transmission line. *Id.* at P 105.

SPP is an RTO that was created following the issuance of Order No. 888. As an RTO, SPP’s tariff governs GIPs for the utilities in its service area. *Sw. Power Pool, Inc.*, OATT, attach. V, § 3. These GIPs specify, among other things, requirements for how a generator interconnects to a transmission owner’s line. *Id.* However, SPP’s GIP was ambiguous regarding whether the interconnection customer or the transmission owner needed to pay for any necessary upgrades to the transmission network because of the interconnection. *Id.* § 11.4.

The two options in a standard GIP tariff are for the interconnector to fund the upgrades or for the transmission owner to fund the upgrades. It is regular practice for interconnection customers to fund network upgrades, but SPP’s application proposed to clarify how a transmission owner may recover capital if it chooses to fund the upgrades. Marked Tariff Filing §§ 8.4.5, 11.4, 15, *Sw. Power Pool, Inc.*, Docket No. ER22-2968.

SPP proposed that if the transmission owner unilaterally elected to fund upgrades, they could then recover the cost of those upgrades, and a return on the invested capital, from the interconnection customer. *Id.* § 11.4, app. 17. SPP further proposed that if a transmission owner made this election, it would be non-binding such that the transmission owner could back out of its decision later in the interconnection process. *Id.* § 8.4.5. Transmission owners within SPP argued that this would promote administrative efficiency and pointed to FERC’s approval of a similar proposal from the Midcontinent Independent System Operator (MISO).

The main opposition to this proposal came from Clean Energy Advocates. They argued that allowing transmission owners to make a non-binding decision on funding the network upgrades will cause immense uncertainty and make it difficult to obtain financing. Clean Energy Advocates Deficiency Response Protest at 10-11, *Sw. Power Pool, Inc.*, Docket No. ER22-2968 (Mar. 7, 2023). SPP disagreed, stating that the proposal increased certainty by allowing a transmission owner to state, early in the proposal process, whether they will consider funding the network upgrades. Answer of Sw. Pub. Serv. Co. at 10-11, *Sw. Power Pool, Inc.*, Docket No. ER22-2968 (Mar. 22, 2023). Clean Energy Advocates responded by showing that SPP’s proposal was unlike the MISO order where transmission owners were required to make binding decisions on network upgrades at the second stage of the study process. *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER20-2632-000 (Oct. 1, 2020) (delegated order).

FERC agreed with Clean Energy Advocates, finding that the proposal was not just and reasonable, and that Order No. 2003, 104 FERC ¶ 61,103 (July 24, 2003), explicitly asks transmission providers to facilitate market entry for generation competitors by reducing interconnection costs and time, which this proposal did not complete. *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,015, at PP 105–06 (Apr. 14, 2023). They further found that non-binding decisions could lead to greater uncertainty, which could encourage interconnection customers to invest time and resources to pursue the interconnection study process, only to later learn in the negotiation phase—after multiple economic studies have been completed—that its project will no longer be economically viable due to increased network upgrade costs. *Id.* at PP 107–08.

Overall, FERC continued to support a policy of allowing GIPs to be processed separate from rate-based utility investments in transmission, and to follow the standard GIP rather than to experiment with new vehicles for utility investment and returns. The key factor in this decision appeared to be the certainty of the investment to be made from utilities.

ENVIRONMENTAL

Nicole Rushovich & Betsy Temkin, Reporters

Orphaned Well Programs Are Not One-Size-Fits-All

The Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law (BIL), Pub. L. No. 117-58, 135 Stat. 429 (2021), provided the largest investment in American history to respond to legacy environmental impacts, including allocating $4.7 billion to “plug, remediate, and reclaim” (referred to herein as “closure” or “close”) orphaned oil and gas wells nationwide. 42 U.S.C. § 15907. The BIL defines what qualifies as an orphaned well on federal and tribal lands, but otherwise explicitly defers the definition of an “orphaned well” to each state. Interestingly, the BIL does not prescribe a well closure prioritization scheme based on methane emissions or otherwise and, at least for now, the U.S. Department of the Interior (DOI), which is administering the grant program, is allowing states to set their own priorities. Whether or not DOI will continue to fully defer to the states in this regard as the program grows and matures seems unlikely.

<u>Orphaned Well Program</u>

The BIL’s Orphaned Well Program spreads its investment across three programs: (1) $4.3 billion to close orphaned wells on state and private lands, (2) $250 million to close orphaned wells on federal lands, and (3) $150 million to close orphaned wells on tribal lands. 42 U.S.C. § 15907(h)(1). This funding can be used to inventory and prioritize orphaned wells and well pads for closure and can also be used to identify “potentially responsible parties,” or a related surety or guarantor, for reimbursement of closure costs, among other activities. *See id.* § 15907(b)(2), (c)(2), (d)(2). The BIL only explicitly references the remediation and reclamation of well pads and related facilities, soil, and land, and is silent as to the addressing any associated surface or groundwater impacts. *See, e.g.*, *id.* § 15907 (b)(2)(B) (permitted activities for federal funding). However, DOI guidance encourages states to track certain data, including surface and groundwater remediation, to “ensure that the Federal resources utilized are well-spent.” DOI, “FY 2022 State Initial

Grant Guidance," at 12 (Apr. 11, 2022) (Initial Grant Guidance). Since the BIL was passed in late 2021, DOI has also established the Federal Orphaned Wells Office and issued guidance to the states and tribes on grant funding to close orphaned oil and gas wells. *See* Press Release, DOI, "Secretary Haaland Establishes Orphaned Wells Program Office to Implement Historic Investments from Bipartisan Infrastructure Law" (Jan. 10, 2023); DOI, "Phase 1 (Fiscal Year 2023) State Formula Grant Guidance" (Jan. 30, 2023) (Draft Formula Grant Guidance); DOI, "Final Tribal Grant Guidance" (Nov. 17, 2022); DOI, "FY 2022 Initial Grant Guidance" (Apr. 11, 2022).

DOI started distributing funding for BIL well closure work in 2022. In May 2022, DOI announced an initial investment of $33 million to address 277 orphaned wells on federal lands. *See* Press Release, DOI, "Biden-Harris Administration Announces $33 Million Infrastructure Investment to Address Legacy Pollution, Spur Good-Paying Jobs on Public Lands" (May 25, 2022). In August 2022, DOI distributed another $560 million as "Initial Grants" to 24 states to begin addressing over 10,000 orphaned wells on state and private land. *See* Press Release, DOI, "Through President Biden's Bipartisan Infrastructure Law, 24 States Set to Begin Plugging over 10,000 Orphaned Wells" (Aug. 25, 2022). Fifteen states intend to use Initial Grant funds to develop methane measuring capabilities. *Id.* (The BIL sets forth certain reporting requirements for the Orphaned Well Program, including an annual estimate of methane emissions from orphaned wells and emission reductions from cleaning up orphaned wells. 42 U.S.C. § 15907(f)(2).) Twelve states intend to prioritize focusing on orphaned wells in disadvantaged communities. *Id.* Several more states intend to prioritize job creation with a preference to small businesses through their contracting process. *Id.* The Initial Grants were the first of three state grant awards under the BIL for orphaned well closures. Subsequent state funding will be via "Formula Grants" and "Performance Grants." 42 U.S.C. § 15907(c)(1). Formula Grants will be issued based on an eligibility formula, including consideration of factors such as job losses in the oil and gas industry, number of orphaned wells within the state, and projected closure costs. *Id.* § 15907(c)(4). Performance Grants will be available for states that have strengthened state oil and gas regulations or financial assurance for oil and gas wells. *Id.* § 15907(c)(5).

<u>Federal Orphaned Well Program</u>

As defined in the BIL, an "orphaned well" on federal or tribal land is a well that is "not used for an authorized purpose, such as production, injection, or monitoring," and either the operator cannot be located, the operator is unable to close the well site, or the well is located in the National Petroleum Reserve in Alaska. *Id.* § 15907(a)(5)(A).

The BIL is silent as to how well closure priorities should be set, leaving that question to DOI. An interagency group led by the Bureau of Land Management (BLM) has been tasked with developing a method to prioritize and rank orphaned wells for closure based on

> public health and safety, ongoing and potential environmental harm, emissions of methane and other harmful air pollutants, proximity to disadvantaged or underserved communities, potential for increased risk due to climate change, and other subsurface impacts or land use priorities, including consideration of state or Tribal plans or priorities for orphaned wells on state, private, or Tribal lands.

"Memorandum of Understanding Between The Department of the Interior; And The Department of Agriculture; And The Department of Energy; And The Environmental Protection Agency; And The Interstate Oil and Gas Compact Commission on Orphaned Well Site Plugging, Remediation, and Restoration" (Jan. 14, 2022).

While this method has yet to be published, it may be similar to guidance BLM has previously issued on the prioritization of orphaned well closures. *See* BLM, Instruction Memorandum No. 2021-039, "Orphaned Well Identification, Prioritization, and Plugging and Reclamation" (July 13, 2021) (IM 2021-039). The BLM Memorandum provided a priority scoring sheet for orphaned wells, listing 11 well conditions with a possible score of 0 to 5 for most conditions. For example, if the well was leaking from the surface, but the wellbore configuration was known, it would score a 0 for the wellbore configuration condition and a 5 for the surface leak. *Id.* The closer the well scores to the maximum score of 51, the higher the orphaned well should be prioritized for cleanup. *Id.*

<u>State Orphaned Well Programs</u>

The BIL defines "orphaned well" with respect to state or private land as "the meaning given the term by the applicable State; or . . . if that State uses different terminology, has the meaning given another term used by the State to describe a well eligible for plugging, remediation, and reclamation by the State." 42 U.S.C. § 15907(a)(5)(B).

In April 2022, DOI issued guidance on its Initial Grant funding program. *See* Initial Grant Guidance, *supra*. The Initial Grant Guidance includes best practices for establishing, conducting, and reporting on well plugging and remediation efforts. Notably, DOI recommends, but does not require, that states include in their grant applications "[d]etails of the State's prioritization process for evaluating and ranking orphan wells." *Id.* at 7. As a result, each state gets to define "orphaned well" and how to prioritize their plugging and remediation work.

As of January 2023, DOI has released draft guidance on how states should apply for $500 million in Formula Grants. *See* Draft Formula Grant Guidance, *supra*. Of note, compared to the Initial Grant Guidance, the Draft Formula Grant Guidance requires states to include a description of the process to "identify and prioritize . . . orphaned wells based on threats to public health and safety, environmental harm – particularly harms due to methane emissions – and other land use priorities . . . ." *Id.* at 7. It also requires states to detail how they will "identify and prioritize the highest methane emitters." *Id.* at 8.

Texas and Pennsylvania are two examples of states that have taken distinctive approaches to defining and prioritizing orphaned well plugging and remediation work thus far.

Texas

In October 2022, Texas became the first state to use BIL funds to close orphaned wells. *See* Mella McEwen, "Texas Becomes First State to Plug Wells with Federal Grants," *Midland Reporter-Telegram* (Oct. 21, 2022). Texas has now closed over 500 of an estimated 7,500 orphaned wells, prioritizing wells that are high risk to the environment. *See* R.R. Comm'n of Tex. (RRC), "Federally Funded (IIJA) Well Plugging," https://www.rrc.texas.gov/resource-center/data-visualization/oil-gas-data-visualization/federally-funded-well-plugging-data-visualization/.

For BIL funding purposes, Texas defines an orphaned well as an "inactive, non-compliant well that has been inactive for a minimum of 12 months, and the responsible operator's Organizational Report, an operator's registration with the [State,] is delinquent." RRC, Application for Infrastructure Investment and Jobs Act Sec. 40601 Orphaned Well Program (submitted May 2022). Texas prioritizes the cleanup of eligible wells that pose a high risk to the environment by assigning numerical values to four overarching criteria in its Well Plugging Priority System: (1) well completion; (2) wellbore conditions; (3) well location with respect to sensitive areas; and (4) unique environmental, social, or economic concern. *Id.* at A11–12 (pp. 36–37). Each category has approximately seven factors that are assigned a preset value between 1 and 50, with most factors valued between 5 and 10. *Id.* Wells that receive a score over 75 are the highest priority behind leaking wells, regardless of their score. *Id.* For example, a well that has failed a mechanical integrity test is awarded 5 points, a well in a marine environment is awarded 10 points, and a well with fluid levels at or above the base of the deepest usable quality water is awarded 50 points. *Id.*

Pennsylvania

Pennsylvania, "the birthplace of the oil industry," also received BIL funds in early 2023 to initiate plugging and remediation work on an estimated 27,000 orphaned wells, the highest number of orphaned wells in the nation. *See* Bobby Magill, "Orphan Well Cleanup in Pennsylvania Underscores Enormity of Task," *Bloomberg Law* (Feb. 9, 2023).

Pennsylvania defines an "abandoned well" as any well that (1) has not produced oil or gas in the preceding 12 months, (2) the production equipment has been removed, or (3) has not been equipped for production within 60 days of drilling. 58 Pa. Cons. Stat. § 3203. An "orphaned well" is "[a] well abandoned prior to April 18, 1985, that has not been affected or operated by the present owner or operator and from which the present owner, operator or lessee has received no economic benefit other than as a landowner or recipient of a royalty interest from the well." *Id.* While orphaned wells in Pennsylvania are also abandoned, not all abandoned wells are orphaned. But both abandoned and orphaned wells are subject to closure by the state and therefore are eligible for BIL grant funding. *See* 42 U.S.C. § 15907(a)(5)(B) (defining a state "orphaned well" for purposes of BIL funding as "the meaning given another term used by the State to describe a well eligible for plugging, remediation, and reclamation by the State"); 58 Pa. Cons. Stat. § 3220 ("If a well is an orphan well or abandoned without plugging . . . , the department may enter upon the well site and plug the well . . . .").

In prioritizing its large inventory of wells for closure, Pennsylvania assigns numeric scores based on risk determined through site investigations. Pa. Dep't of Env't Prot. (PADEP), "Abandoned and Orphan Oil and Gas Wells and the Well Plugging Program Fact Sheet" (last revised Apr. 2021). The highest priority is abandoned wells that pose "imminent threats to public safety, then to wells that are actively harming the environment." PADEP, "Frequently Asked Questions—Implementation of the Infrastructure Investment and Jobs Act: Orphan and Abandoned Well Plugging" (May 25, 2022). Consideration is then given to the proximity of the well to certain features like water supplies or homes and other hazards posed by features of the well site, such as open tanks. *Id.* Notably, "[t]he current prioritization process considers the presence or absence of methane emissions but does not require quantification of those emissions." *Id.*

Federal and state orphaned well programs have different criteria for what constitutes an orphaned well and how to prioritize well closures. This also has resulted in significant differences across state-level closure initiatives. While this is partially driven by the BIL's statutory directive, these differences will likely narrow to some degree as the program matures. The Draft Formula Grant Guidance previews the possibility of setting more uniform priorities for well closures at the state level in the future.

CONGRESS/FEDERAL AGENCIES

John H. Bernetich & Dale Ratliff, Reporters

BLM Publishes Proposed Conservation Rule

On April 3, 2023, the Bureau of Land Management (BLM) published proposed revisions to its land use planning and management regulations under the Federal Land Policy and Management Act (FLPMA). *See* Conservation & Landscape Health, 88 Fed. Reg. 19,583 (proposed Apr. 3, 2023) (to be codified at 43 C.F.R. pts. 1600, 6100). The proposed conservation rule has the potential to significantly alter the framework under which BLM manages public lands.

The conservation rule has three main components:

(1) The rule proposes to identify "conservation" as a specific "use" under FLPMA "on par with other uses of the public lands under FLPMA's multiple-use and sustained-yield framework." *Id.* at 19,584.

(2) The rule proposes to revise BLM's procedures for designating areas of critical environmental concern (ACECs), "give priority to the designation and protection of ACECs," and "emphasize ACECs as the principal designation for protecting important natural, cultural, and scenic resources." *Id.*

(3) The rule proposes to create a new management tool—conservation leases—that could be issued for the restoration or protection of leased lands, or to create a durable mechanism for compensatory mitigation activities. *Id.* at 19,586.

Management and Planning for Conservation

The rule proposes to define conservation as "maintaining resilient, functioning ecosystems by protecting or restoring natural habitats and ecological functions." *Id.* at 19,598. The rule would require BLM to recognize "[c]onservation as a land use within the multiple use framework, including in decisionmaking, authorization, and planning processes." *Id.* at 19,590. Management for conservation would require that BLM, among other things: (1) put tracts of public land into "a conservation use, such as by appropriately designating or allocating the land, to maintain or improve ecosystem resilience," during the planning process; (2) "include a restoration plan in any new or revised Resource Management Plan"; and (3) "prioritize actions that conserve and protect intact landscapes." *Id.* at 19,590, 19,599.

ACEC Revisions

The rule would "emphasize the requirement that the BLM give priority to the identification, evaluation, and designation of ACECs during the planning process as required by FLPMA and would provide additional clarity and direction for complying with this statutory requirement." *Id.* at 19,593. The proposed revisions to the ACEC regulations include:

- a requirement that "authorized officers to identify areas that may be eligible for ACEC status early in the planning process";
- "more specificity for determining whether an area meets the criteria for ACEC designation of relevance, importance, and requiring special management attention";
- identification that "resources, values, systems, or processes may meet the importance criterion if they contribute to ecosystem resilience, including by protecting landscape intactness and habitat connectivity";

- new emphasis "that resources, values, systems, processes, or hazards that are found to have relevance and importance are likely to warrant special management attention";
- requirement that all land use plans "include at least one plan alternative that analyzes in detail all proposed ACECs";
- removal of "the existing requirement in current § 1610.7-2(b) that the BLM publish a Federal Register notice relating to proposed ACECs and allow for 60 days of comment, in addition to the other Federal Register publication requirements that apply to land use planning"; and
- replacement of the term "value" "with the phrase 'resources, values, systems, processes, or hazards.'"

Id.

<u>Conservation Leases</u>

A central feature of the conservation rule is the proposed creation of a new BLM land use authorization—conservation leases. "Conservation leases could be issued to any qualified individual, business, non-governmental organization, or Tribal government" and "either for 'restoration or land enhancement' or 'mitigation.'" *Id.* at 19,591. Leases issued for restoration or land enhancement "would be issued for a renewable term of up to 10 years, whereas a lease issued for mitigation purposes would be issued for a term commensurate with the impact it is mitigating." *Id.*

BLM is requesting public comment on six specific parts of the conservation-leasing proposal:

- Is the term "conservation lease" the best term for this tool?
- What is the appropriate default duration for conservation leases?
- Should the rule constrain which lands are available for conservation leasing? For example, should conservation leases be issued only in areas identified as eligible for conservation leasing in an RMP or areas the BLM has identified (either in an RMP or otherwise) as priority areas for ecosystem restoration or wildlife habitat?
- Should the rule clarify what actions conservation leases may allow?
- Should the rule expressly authorize the use of conservation leases to generate carbon offset credits?
- Should conservation leases be limited to protecting or restoring specific resources, such as wildlife habitat, public water supply watersheds, or cultural resources?

Id.

There are a number of open and interesting questions about the proposed conservation rule. For example, will the rule cause BLM to delay ongoing planning efforts, such as the proposed revisions to the Western Solar Plan, in order to first finalize the conservation rule and implement its direction. The rule also states that conservation leases are "not intended to provide a mechanism for precluding other uses, such as grazing, mining, and recreation." *Id.* But it will be interesting to watch if BLM creates a specific mechanism that would allow the agency to monitor and enforce against conservation leasing for obstructionist purposes, or if conservation leases will become a tool that third parties can effectively use to preclude other uses, such as grazing or oil and gas leases. BLM is accepting public comment on the proposed conservation rule until June 20, 2023.

EPA Proposes New Standards for GHG Emissions from Fossil Fuel-Fired Power Plants

On May 23, 2023, the U.S. Environmental Protection Agency (EPA) published a comprehensive proposed rule that would establish new standards for greenhouse gas (GHG) emissions from new, modified, reconstructed, and existing fossil fuel-fired power plants. *See* New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (proposed May 23, 2023) (to be codified at 40 C.F.R. pt. 60). EPA projects that the standards would reduce total GHG emissions from new fossil fuel-fired power plants by 617 million metric tons by 2042. *Id.* at 33,409.

The proposed rule includes a suite of actions under section 111 of the Clean Air Act, 42 U.S.C. § 7411. 88 Fed. Reg. at 33,243. First, EPA proposed to tighten New Source Performance Standards (NSPS) for GHG emissions from new, modified, and reconstructed fossil fuel-fired power plants under section 111(b) (mostly new natural gas-fired plants). *Id.* The applicable NSPS depends on how often the unit will operate (capacity factor). For units that operate most often, the NSPS is based on potential emission reductions through carbon capture and storage (CCS) or hydrogen co-firing. *Id.* at 33,277.

Second, EPA proposed to issue emission guidelines under section 111(d) for (1) large, frequently-used existing stationary combustion turbines (primarily natural gas-fired plants) and (2) existing steam generating units (primarily existing coal plants). *Id.* at 33,243. The emission guidelines for existing gas plants generally mirror the guidelines for new, modified, and reconstructed gas plants. *Id.* at 33,361. As to existing coal units, EPA proposed to set different standards that would focus on the unit's planned retirement date ("operating horizon"). EPA recognized that many coal plants have a limited operating horizon, and accordingly proposed to require coal plants that plan to operate past 2040 to reduce emissions based on CCS technology. *Id.* at 33,341. Coal plants that plan to retire before 2032 are effectively grandfathered out of the emission guidelines.

Finally, EPA proposed to repeal the Trump administration's Affordable Clean Energy Rule, which established less restrictive standards and guidelines under section 111. *Id.* at 33,335–36; *see* 84 Fed. Reg. 32,520 (July 8, 2019).

The proposed rule follows the U.S. Supreme Court's 2022 decision in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), which clarified that EPA must base emission guidelines for existing sources under section 111(d) on pollution controls or measures that can be applied on-site at power plants, rather than at the grid level. In *West Virginia*, the Court ruled that EPA's 2015 Clean Power Plan, issued by the Obama administration, exceeded EPA's authority under section 111(d) because it based emission guidelines on pollution controls that would be imposed at the grid level. EPA's proposal is intended to fit within the guardrails established in *West Virginia*, while still achieving substantial GHG emissions reductions.

EPA is accepting public comment on the proposed rule until July 24, 2023.

FEDERAL ENERGY REGULATORY COMMISSION

Kirk Morgan, Boris Shkuta & Molly Behan, Reporters

Proposed Expansion of Duty of Candor Rule

Perhaps the proceeding potentially impacting the greatest number of market participants across the various activities regulated by the Federal Energy Regulatory Commission (FERC) is FERC's proposal to expand the duty of candor rule to entities other than to sellers of electricity.

FERC issued the associated notice of proposed rulemaking (NOPR) on July 28, 2022, in Docket No. RM22-20, which generated significant industry interest and comments by a variety of market participants as well as members of Congress. Duty of Candor, Notice of Proposed Rulemaking, 180 FERC ¶ 61,052 (2022). In the NOPR, FERC proposes to expand the applicability of the duty of candor, which is a general requirement that market participants must be truthful, forthcoming, and must not submit false or misleading information in matters related to FERC.

The crux of the proposed expansion involves the universe of issues to which FERC's existing duty of candor will apply. In other words, the NOPR does not necessarily expand the type of behavior that is expected in connection with this duty; instead, it expands the circumstances and communications to which the duty is applicable. Under the NOPR, *any* entity communicating with FERC or with a FERC-jurisdictional entity, when the communication is related to a matter subject to the jurisdiction of FERC, would be subject to the duty of candor. Possible violations of the duty of candor could be avoided through a demonstration by the communicator that the alleged error or inaccuracy—even if unintentional—could not have been avoided through the exercise of due diligence.

Under a variety of current rules, regulated entities (natural gas pipelines and marketers actively participating on FERC-jurisdictional markets, as well as market-based rate power sellers, to name a few) are subject to various truthfulness requirements. *See, e.g.*, 18 C.F.R. §§ 1c.1(a)(2), .2(a)(2) (it is unlawful, in connection with natural gas and electric transactions, "[t]o make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made . . . not misleading"). Individuals and entities appearing before FERC in formal proceedings are also subject to a variety of truthfulness requirements. *See Black Marlin Pipeline Co.*, 4 FERC ¶ 61,039, 61,089 (1978) (FERC has interpreted 18 C.F.R. § 157.5 to require certificate applicants under Natural Gas Act § 7 to disclose "fully and forthrightly . . . all information relevant to the application"). Under the newly proposed rules, a blanket duty of candor would be applicable to all communications by any entity with FERC or a FERC-jurisdictional entity. *See* NOPR at P 23 ("[FERC] proposes to adopt a new section within 18 CFR part 1 to require that entities ensure the accuracy of communications related to a matter subject to [FERC]'s jurisdiction when communicating with the following entities: [FERC], [FERC]-approved market monitors, [FERC]-approved RTOs, [FERC]-approved ISOs, jurisdictional transmission or transportation providers, or the Electric Reliability Organization and its associated Regional Entities.").

Should FERC adopt these changes, then entities not otherwise subject to FERC jurisdiction may be found liable for breaching the duty of candor in communications with FERC-jurisdictional entities. Further, communicators will have the burden of demonstrating that due diligence could not have helped the communicator avoid making the false or misleading communication.

Comments filed in response to the NOPR raised concerns regarding the potential chilling effect that the proposed rule could have on entities' willingness to communicate with FERC and with other entities with whom communications would trigger the revised duty of candor requirements. For example, commenters indicated that the expanded requirements could result in liability for predictions made that turned out to be inaccurate; the expanded rule could also impact how parties negotiate settlement agreements and other negotiations related to subject matters regulated by FERC. Other comments were more supportive of the NOPR, encouraging FERC to take action as a way of protecting markets and consumers on issues related to FERC's jurisdiction.

Market participants and interested organizations still await further action from FERC. While the NOPR was issued in July, and comments were filed in November, FERC has still not indicated whether it will issue the proposed revisions as a final rule.

ALASKA – MINING/OIL & GAS

Jonathan Iversen & Connor Smith, Reporters

Alaska Legislature Debates Oil and Gas Production Taxes—Again

It is no secret that the oil and gas industry—and revenues from it—are vital to the state of Alaska and its citizens, and the oil and gas industry is a major employer in the state. "Unrestricted" revenues, meaning revenues available to fund general state operations and capital projects, have historically been the focus of the budget debate that recurs every year in Alaska, with the governor and various factions of the legislature sparring over competing agendas. Unrestricted revenues are largely comprised of royalties for oil produced from state leases and three types of taxes:

(1) *Oil and Gas Production Tax*. A production (severance) tax levied on oil and gas produced in the state with a base tax rate of 35% of the net proceeds of production. Alaska Stat. §§ 43.55.011–.180.

(2) *Petroleum Property Tax*. An ad valorem tax of 20 mills (2%) levied on the assessed value of oil and gas exploration, production, and pipeline transportation properties in the state; municipalities and boroughs receive proceeds based on their mill rates, with remainder to the state. *Id.* §§ 43.56.010–.210.

(3) *Corporate Income Tax*. A net income tax of up to 9.4% on a corporation's Alaska taxable income. For oil and gas corporations, Alaska taxable income is determined by apportioning worldwide income to Alaska relative to the rest of the world based on (i) tariffs and sales, (ii) oil and gas production, and (iii) oil and gas property. *Id.* §§ 43.20.011–.053.

Alaska's oil and gas production taxes, royalties, and corporate income taxes are all sensitive to prices and production volumes, resulting in significant variability and uncertainty in the state's revenue stream.

Although there have been numerous tax bills introduced in the Alaska legislature over the last few years, including bills that would impose broad-based individual income taxes and sales taxes, the oil and gas production tax seems to be a perennial source of debate and has been revised, if not overhauled, on a number of occasions, particularly since 2005. The production tax is again in the crosshairs this year with the introduction of Senate Bill 114 (SB 114).

Given the complexity and uniqueness of Alaska's production tax structure, an introduction to the tax facilitates a basic understanding of SB 114's potential impact. Unlike other states in the lower 48, Alaska levies the tax on the "production tax value" of oil and gas (basically, net revenues of production in the state) as opposed to the gross value at the point of production (which is commonly referred to as "wellhead" value). *Id.* §§ 43.55.011(e), .020(e). The calculation of net revenue begins with the destination (market) value less the pipeline and marine transportation costs to get from the point of production to the destination market. This yields the wellhead value. Direct operating and capital costs of oil and gas exploration, development, and production upstream of the point of production are then subtracted from the wellhead value to reach net revenue. *Id.* §§ 43.55.150, .160. Net revenue is then multiplied by the 35% tax rate (for oil) and the result is reduced by credits.

One of the production tax credits is for $5 per taxable barrel for certain taxable North Slope (north of 68 degrees North latitude) oil produced from comparatively newer fields. *Id.* § 43.55.024(i). To be eligible, the taxable production must satisfy certain statutory criteria, and the $5 per barrel is only available for oil and gas produced from each property for a certain period of time.

North Slope oil production from "legacy fields" that does not qualify for the $5 per barrel credit qualifies for a production tax credit under section 43.55.024(j), referred to as the "per barrel" or "sliding scale" credit. This credit decreases as oil prices rise, and the maximum credit is $8 per barrel of taxable oil if the average wellhead value for the month is less than $80 per barrel. If the average wellhead value exceeds $80 per barrel but is less than $90 per barrel, the credit is $7 per barrel. The amount of credit continues to drop by $1 for each $10 incremental increase in wellhead value and is zero if the average wellhead value for the month is $150 per barrel or higher.

The original version of SB 114 would have added an element of ringfencing to the oil and gas production tax, such that for unitized oil and gas properties on the North Slope, the tax would be calculated at the unit level—the level at which oil and gas leases are unitized for an oil and gas field. This would, among other things, confine the use of upstream unit expenditures in the calculation such that they could only be used in the calculation of production taxes for that unit's production. Given the additional complexity associated with ringfencing, the Senate Finance Committee deleted the ringfencing provisions shortly after SB 114 received its introductory hearing.

But other aspects of SB 114 that would dramatically increase production taxes remain. The bill would reduce the sliding scale credit by $3 per barrel at each increment, such that the highest level of credit would be $5 per barrel rather than $8 per barrel when wellhead value is less than $80 per barrel. The credit would still be reduced by $1 per barrel for each $10 increase in wellhead value, so the lowest level of credit would be $1 per barrel when wellhead value is equal to or greater than $110 per barrel and less than $120 per barrel.

The bill would also limit the use of the $5 per barrel credit and sliding scale credit to the amount of the producer's capital expenditures for the lease, property, or unit for the calendar year. This would represent a substantial constraint on producers' ability to use these credits and by all appearances constitutes an element of ringfencing.

In regard to the new income tax, SB 114 would impose the tax on a "qualified entity" at a rate of 9.4% on "qualified taxable income" over $4 million per year. "Qualified entity" is defined as a partnership, sole proprietorship, or S corporation, and the tax would not apply to corporations paying the Alaska corporate income tax. "Qualified taxable income" is defined as income from oil and gas production or transportation in Alaska.

This regular legislative session ended on May 17, 2023, and SB 114 did not make it out of committee before that time. However, this is the first session of this legislature and bills that are introduced this session may still be acted on during the second session—that is not an insignificant risk with the number of tax bills floating around and the continued concern about the budget deficit.

Alaska Supreme Court Allows Mining Company to Cure Abandoned Claims Years Later

In a published decision issued on April 21, 2023, *Teck American Inc. v. Valhalla Mining, LLC*, No. S-18082/18101, 2023 WL 3029704 (Alaska Apr. 21, 2023), the Alaska Supreme Court rubber-stamped the Alaska Department of Natural Resources' (DNR) interpretation of former Alaska Stat. § 38.05.265, ruling that a mining company could cure abandoned claims years after abandonment and even after another mining company had located intervening claims and subsequently abandoned them. (Section 38.05.265 was amended by the Alaska legislature effective April 30, 2020. The court's decision and this analysis address the pre-amendment version of the statute.)

The dispute surrounded the ownership of the "Smucker" claims, which were located in 1994 by Cominco American Inc. The claims were later conveyed to Teck Cominco American Inc., which changed its name to TCAI, Inc. (TCAI), in 2008. That same year, TCAI filed statements of labor for the Smucker claims that failed to identify TCAI as owner. Pursuant to former section 38.05.265(a), TCAI's failure to identify the owner of the claims in 2008 constituted abandonment as a matter of law.

In 2011, American Energies Resources, Inc. (AERI), located the abandoned Smucker claims, but AERI's successor eventually abandoned the claims in 2016. Then, in 2017, TCAI attempted to cure its ownership of the Smucker claims under former section 38.05.265(b) by recording corrected statements of labor and paying DNR the associated fees and penalties proscribed by the statute. TCAI then quitclaimed the Smucker claims to Teck American Inc. (Teck). Just three months after TCAI attempted to cure, another mining company—Valhalla, Inc. (Valhalla)—attempted to locate claims that overlapped with the Smucker claims.

DNR refused to issue permits to Valhalla for the overlapping claims, reasoning that TCAI had cured its abandonment of the Smucker claims before Valhalla had located its claims, and therefore Teck was the rightful owner of the claims. Valhalla ultimately appealed to the Alaska Superior Court, which overturned DNR's holding and ruled that the claims belonged to Valhalla. Teck and DNR appealed that ruling to the Alaska Supreme Court.

On appeal, the Alaska Supreme Court interpreted the following portion of former section 38.05.265(b):

> Unless another person has located a mining claim . . . that includes all or part of the mining claim or leasehold location abandoned under (a) of this section or the area is closed to mineral location . . . a person may cure the failure to record or pay rents or royalties that constituted the abandonment and cure the abandon-

> ment by (1) properly recording a certificate of location or a statement of annual labor, paying any required annual rental, and paying any required production royalty; and (2) paying a penalty equal to the annual rent for the mining claim or leasehold location that was abandoned under (a) of this section.

Teck, 2023 WL 3029704, at *5. The court applied the reasonable basis standard to review DNR's interpretation and application of former section 38.05.265, concluding that DNR's interpretation was reasonable and reversing the superior court.

The court was persuaded by legislative history from 2004 when the cure provision was added to the statute, explaining that the legislature wanted to create a process to cure abandoned mining claims, so long as the cure did not displace a subsequent mining claim. *Id.* at *6. The court reasoned that even though AERI located the claims after TCAI abandoned them, the claims were not owned by anyone when TCAI cured its abandonment—and thus no subsequent mining claim was displaced by TCAI's efforts. *Id.* at *7.

The court established that even though TCAI abandoned the Smucker claims as a matter of law, it retained an interest in the Smucker claims significant enough to withstand another mining company locating claims on the same lands and abandoning them in the intervening years and to allow TCAI to ultimately recover ownership of the claims. *Id.* at *8–9.

ARIZONA – MINING

Paul M. Tilley, Reporter

Arizona Court of Appeals Affirms in Part the Arizona Navigable Stream Adjudication Commission's Findings on Navigability

On February 7, 2023, the Arizona Court of Appeals affirmed in part the findings of the Arizona Navigable Stream Adjudication Commission (ANSAC) that sections of the Verde, Salt, and Gila rivers were non-navigable when Arizona became a state in 1912. However, the court disagreed with ANSAC's findings regarding one segment of the Gila River near Yuma, Arizona, and concluded that this section was navigable as a matter of law when Arizona entered the union in February 1912. *Defenders of Wildlife v. Ariz. Navigable Stream Adjudication Comm'n*, 525 P.3d 641, 649 (Ariz. Ct. App. 2023).

When Arizona became a state on February 14, 1912, it joined the union on equal footing with the other states. This meant that Arizona took title to the beds of any streams and rivers in the state that were navigable waters at that time. In 1992, the Arizona state legislature created ANSAC to determine the title to riverbeds in Arizona. Prior to ANSAC's creation, the Arizona legislature attempted to resolve conflicting riverbed title claims by relinquishing Arizona's interest in streambeds in the state. *Id.* at 649. These efforts were ruled unconstitutional in 1992 and ANSAC was created shortly after this ruling. ANSAC has since adjudicated the navigability of 39,000 waterways in Arizona. *Id.*

ANSAC's adjudication of the Verde, Salt, and Gila rivers occurred over a series of hearings between 2003 and 2006. *Id.* ANSAC determined the three rivers were non-navigable at statehood. The Arizona Superior Court vacated those determinations based on ANSAC's failure to consider diversions and other human impacts that may have impacted streamflow. ANSAC reconsidered its determination and held a second round of hearings in 2014 and 2016. The parties presented expert testimony regarding the waterway's natural state and human usage prior to and shortly after statehood. ANSAC adopted the Arizona State Land Department's (ASLD) segmentation of the rivers for purposes of its decision. The section that received the most scrutiny by the court of appeals was segment 8 of the Gila River. Segment 8 is the westernmost portion of the Gila River that stretches from the confluence of the Gila and Colorado rivers in Yuma, Arizona. In 2018, a majority of ANSAC's board ruled that all segments of the Verde, Salt, and Gila rivers were non-navigable at statehood. *Id.* A proponent of navigability, Defenders of Wildlife (DOW), challenged ANSAC's determination in superior court. DOW did not prevail and appealed. *Id.*

DOW argued in part that the evidence presented did not support ANSAC's conclusions, and that ANSAC applied the wrong legal standard in determining the three rivers were non-navigable. *Id.* at 649–50. DOW argued that ANSAC improperly considered testimony from individuals not qualified as boating experts. DOW asserted that the relevant witnesses never boated the Verde River or attempted the same. The court of appeals disagreed. It determined that the expert's experience as a hydraulic engineering manager and history consulting on river hydrology was sufficient. The court noted that the expert did need to carry the title of "boating expert" in order to speak to the rivers' navigability by watercraft. *Id.* at 651. DOW also took the position that ANSAC relied on non-relevant evidence such as non-boating transportation, land grants, and land patents when making its determination. The court disagreed. It found that DOW's reliance on the *Defenders of Wildlife v. Hull*, 18 P.3d 722, 726 (Ariz. Ct. App. 2001), decision, which DOW asserted precludes the use of non-boating transportation in making a navigability determination, was misplaced and overstates the holding in *Hull*. The court noted that the court in *Hull* acknowledged other courts found evidence of non-boating transportation relevant, and that the court in *Hull* did not expressly say such evidence is irrelevant. *Id.* Further, the court noted that the record did not indicate ANSAC relied on such evidence or found it highly probative in making its findings on non-navigability. The court also rejected the argument advanced by the Salt River Pima-Maricopa Indian Community that Arizona's delay in asserting title to Verde, Salt, and Gila rivers is evidence of non-navigability.

The court of appeals next looked to DOW's argument that ANSAC misapplied the legal test for navigability. The court noted that Arizona state law aligns with the test outlined in *Daniel Ball*, 77 U.S. (10 Wall.) 557 (1870), but uses slightly different wording. The text of Ariz. Rev. Stat. § 37-1101.5 provides that a navigable river is, for purposes of determining title, one that is "in existence on February 14, 1912, and at that time was used or was susceptible to being used, in its ordinary and natural condition, as a highway for commerce, over which trade and travel were or could have been conducted in the customary modes of trade on water." The court noted that one may interpret the statute differently than the rule in *Daniel Ball*, but the federal test will ultimately control. *Defenders*, 525 P.3d at 652.

The court of appeals outlined what it deemed the "five essential components" of the navigability test. These are (1) the river's ordinary and natural condition at the time of statehood; (2) the types of commerce, in terms of both trade and travel, contemplated at statehood; (3) the customary modes of trade and travel on water at statehood; (4) actual navigation of the river, before and after statehood; and (5) the river's susceptibility to use as a highway for commerce at the time of statehood, assuming the river had been in its ordinary and natural condition. *Id.* at 653. For the first component, the court disagreed with DOW that ANSAC failed to consider evidence of the rivers' ordinary and natural condition from the time after diversions by

Native Americans stopped, but prior to the impacts from Euro-American settlements. *Id.* Rather, the court found that ANSAC considered historical accounts and streamflow measurements from this period. For the second component, the court also disagreed with DOW's argument that ANSAC improperly focused on whether the rivers could be used for commercial purposes. The court noted that if ANSAC considered noncommercial travel it would improperly broaden the scope of the navigability analysis beyond the parameters set in the federal test. *Id.* at 655.

For the third component, the court of appeals agreed in part with DOW's assertion that ANSAC failed to properly consider the use of small, low-draft watercraft. The court found that the record supports ANSAC considering the use of small watercrafts on the relevant portions of the Verde and Salt rivers. But, the court noted that the record does not show ANSAC made a finding about the use of small watercraft on segment 8 of the Gila River. For the fourth component, actual use, the court found no abuse of discretion on ANSAC's part because the record reviewed supports ANSAC's conclusion that historical use was not "regular." *Id.* at 656–57.

For the fifth component, susceptibility to use, the court of appeals noted that ANSAC's analysis on the Verde River was sound, but that its conclusions regarding the Salt and Gila "are closer calls." For the Salt, the court noted that ANSAC placed too much weight on actual and regular commercial use; a river may be navigable either if it was used *or* if it was susceptible to use. But, even in light of this possible shortcoming in ANSAC's analysis the court found that the evidence showing a lack of actual use in a populated area supported ANSAC's non-navigability determination. *Id.* at 657–58. However, the court faulted ANSAC's analysis of the Gila. The court disagreed with ANSAC's view that the Gila's lack of use for mining purposes precluded a navigability finding. The court noted that a lack of use on the Gila for shipping commercial quantities of ore does not lead to the conclusion that other commercial uses may have occurred on the river. Further, the court found that ANSAC's susceptibility analysis missed the mark in concluding that if commercial use is not found then susceptibility to use will also not be found. While this flaw was not fatal for the other river segments it did require a reversal of ANSAC's findings regarding segment 8 of the Gila River. *Id.* at 658.

As noted above, the court of appeals only reversed ANSAC's findings regarding segment 8 of the Gila River. The court found that the record showed that the ordinary and natural conditions of segment 8, along with the commercial demands and watercraft used, would support a finding that the segment would support seasonal commercial use. *Id.* at 662. While the record did show dry periods and seasonal low flows, the court noted that the larger craft with a shallow draft would have been able to navigate segment 8. Further, the record contained reports of numerous trips down segment 8 which included trips after significant diversions occurred on the river. *Id.*

Finally, the court of appeals rejected an argument by the Salt River Project (SRP) that the court may not reverse a navigability finding if the relevant segments of the Salt or Gila would be navigable but for the construction of any dams prior to statehood by the federal government or diversions made pursuant to the Reclamation Act. SRP's position, as characterized by the court, was that the 1910 Arizona-New Mexico Enabling Act reserved the federal government's interest in riverbeds impacted by federal projects initiated prior to statehood and thus the court should find that those projects "have no bearing on the rivers' ordinary and natural condition." *Id.* at 663. The court noted that it will not resolve or address the issue of the federal government's reservation of title to submerged lands because the issue presented to ANSAC was navigability and not riverbed ownership. The court further noted that its prior decisions rejected approaches that would allow ANSAC to ignore the impacts of any dams or diversions constructed prior to statehood. *Id.* And, as a final point, the court noted that it does not need to resolve the impact of its ruling on portions of the riverbeds within the Yavapai-Apache Reservation, Fort McDowell Yavapai Nation, Gila River Indian Reservation, San Carlos Apache Indian Reservation, and Salt River Indian Reservation, because segment 8 of the Gila River was the only portion it deemed navigable at statehood and this stretch of river does not traverse a federally-recognized Indian reservation. As such, the court found that its ruling on navigability and non-navigability does not implicate "any tribe's title to lands in Indian country." *Id.*

ARKANSAS – OIL & GAS

Thomas A. Daily, Reporter

Arkansas General Assembly Enacts Legislation Significantly Expanding Its Underground Storage of Gas Law

The recently concluded 2023 general session of the Arkansas legislature enacted an amendment to Arkansas's Underground Storage of Gas Law, Ark. Code Ann. §§ 15-72-601 to -608. Senate Bill 210, 2023 Arkansas Laws Act 140. The effect of the amendment is to expand the definition of "gas" covered by the statute from only natural gas to include carbon oxides, ammonia, hydrogen, nitrogen, and noble gas, thus empowering the Arkansas Oil and Gas Commission (AOGC) to regulate storage facilities for those gasses.

The Act also expanded the class of entities entitled to utilize eminent domain to acquire underground pore space within a gas storage project from the previous "natural gas public utilities" to include "gas storage facilities."

The revised statute is expected to have immediate positive impact on currently proposed and future carbon dioxide sequestration projects as well as possible underground storage facilities for the other newly included gases. The AOGC intends to seek primacy for permitting and regulation of Class VI carbon dioxide injection wells from the U.S. Environmental Protection Agency.

CALIFORNIA – OIL & GAS

Tracy K. Hunckler & Megan A. Sammut, Reporters

SB 1137 Setback Legislation and CalGEM Emergency Regulations Stayed Pending Voter Referendum

On February 3, 2023, the California Secretary of State announced that the voter referendum on Senate Bill 1137 (SB 1137)—the bill to establish a 3,200-foot setback between new oil wells and sensitive receptors and implementing new requirements for existing wells within the setback zone—had qualified to be placed on the November 5, 2024, ballot. Announcement, "1940. (22-0006) REFERENDUM CHALLENGING 2022 LAW PROHIBITING NEW OIL AND GAS WELLS NEAR HOMES, SCHOOLS, AND HOSPITALS" (Feb. 3, 2023); *see also* Vol. 40, No. 1 (2023) of this *Newsletter*. On the same day, the California Department of Conservation's Geologic Energy Management Division (CalGEM) issued a notice to operators informing them that the provisions of SB 1137 were officially stayed pending a vote on the referendum and, relatedly, that enforcement of CalGEM's emergency regulations implementing the provisions of SB 1137 was suspended by operation of law. Notice to Operators 2023-03, "Suspension of Senate Bill 1137 Requirements" (Feb. 3, 2023) (NTO 2023-03). As acknowledged in NTO 2023-03, "[t]he effectiveness of a statute challenged in its entirety by a duly qualified (or 'valid') referendum is stayed until it has been approved by the voters at the required election." *Id.* (citing *Assembly of State of Cal. v. Deukmejian*, 639 P.2d 939 (Cal. 1982); Cal. Const. art. II, §§ 9, 10). Further, because SB 1137 was stayed, CalGEM's emergency regulations—which were authorized by the provisions of the bill—are also necessarily stayed pending the vote. *Id.*

NTO 2023-03 goes on to explain to operators that (1) for notices of intent (NOIs) approved by CalGEM before February 3, 2023, operators do not need to take any additional steps; (2) NOIs submitted to CalGEM for approval but not yet approved as of February 3 were at that point no longer subject to SB 1137; (3) NOIs that were returned with a request for additional information under SB 1137 could be resubmitted without that requested information; and (4) a notice of new production facility is no longer required. *Id.*

The setback law remains stayed pending a vote on the referendum in November 2024.

SB 556 Aims to Hold Owners and Operators Presumptively Liable for Certain Harm to People Living Within the Setback Zone

Despite the fact that Senate Bill 1137 has been stayed, on February 15, 2023, a bill was introduced in the Senate that, if signed into law, would hold owners and operators of an oil or gas production facility or well with a wellhead presumptively liable for any respiratory ailment in a senior or child, preterm birth or high-risk pregnancy, or cancer diagnosis, where—among other qualifications—the harmed individual was domiciled within the setback zone of 3,200 feet of that facility or wellhead. Senate Bill 556 (SB 556), 2023 Leg., 2023–2024 Reg. Sess. (Cal. 2023) (as amended).

SB 556 offers two complete affirmative defenses: (1) that the owner or operator used "the best available technology and remediation efforts proven to prevent" the alleged harm, and (2) that the facility or well were not the cause of the harm. The bill would also impose a civil penalty of $250,000 to $1 million per harmed individual, and allows for imposition of double or treble damages if a court or jury finds them to be warranted to deter such harm from occurring in the future.

SB 556 passed out of the Senate Judiciary Committee with a 5–2 vote and is now with the Senate Appropriations Committee.

CARB to Phase Out Medium- and Heavy-Duty Combustion Trucks

On April 28, 2023, the California Air Resources Board (CARB) approved a regulation to phase out sales of new medium- and heavy-duty combustion trucks in California by 2036. *See* News Release, Office of Gov'r Gavin Newsom, "California Approves World's First Regulation to Phase Out Dirty Combustion Trucks and Protect Public Health" (Apr. 28, 2023). Under the new regulation, big rigs, local delivery trucks, and government fleets must be zero-emission by 2035; garbage trucks and buses by 2039; and all other medium- and heavy-duty trucks by 2042. The regulations apply to fleets of 50 or more, or to companies with $50 million or more in gross revenue.

CARB unanimously approved the new rules despite pushback from industry professionals urging the State to slow the transition to zero-emission until more such vehicles become available. *See* Wes Venteicher, "California to Phase Out Gas-Powered Trucks and Bus Fleets to Meet Climate Goals," *Politico* (Apr. 28, 2023). Indeed, the industry has argued that not only are vehicles in short supply, but charging them has also proven difficult, with companies often left waiting for the necessary infrastructure. CARB Chair Liane Randolph indicated the rules are meant to drive the supply, saying "[n]o one is going to build infrastructure in the abstract." *Id.*

Lessee Given Final Leave to Amend Takings Claim in Suit Against Ventura County

As last reported in Vol. 39, No. 4 (2022) of this *Newsletter*, Peak Oil Holdings LLC (Peak) sued Ventura County in the U.S. District Court for the Central District of California, asserting a violation of the takings clause of the Fifth Amendment and a violation of the procedural and substantive due process clause of the U.S. Constitution, stemming from the County's ultimate refusal to issue clearance for Peak to exercise certain vested rights it asserts it has under an oil and gas lease, and the related nullification of a 2012 zoning clearance. *See* Complaint, *Peak Oil Holdings LLC v. Cnty. of Ventura*, No. 2:21-cv-00734 (C.D. Cal. Jan. 27, 2021). On October 5, 2022, the court granted the County's motion to dismiss Peak's first amended complaint as to Peak's takings claim with leave to amend, and denied the motion with respect to its due process claim. Peak filed a second amended complaint on October 28, 2022, and the County responded with another motion to dismiss on November 18, 2022, as to the takings claim only. *See* Motion to Dismiss, *Peak Oil Holdings LLC v. Cnty. of Ventura*, No. 2:21-cv-00734 (C.D. Cal. Nov. 18, 2022).

On February 23, 2023, the court issued an order granting the County's motion to dismiss. Order Granting County of Ventura's Motion to Dismiss, *Peak Oil Holdings LLC v. Cnty. of Ventura*, No. 2:21-cv-00734, 2023 WL 2541994 (C.D. Cal. Feb. 23, 2023), *appeal docketed*, No. 23-55239 (9th Cir. Mar. 16, 2023). Therein—as in its previous orders concerning Peak's initial and first amended complaints—the court found Peak again failed to allege facts supporting that it has a vested property right necessary to assert a government taking. In attempting to allege that the conditional use permit (CUP) that Peak acquired in 2012 vested earlier, before the 1983 ordinance at issue in the litigation, Peak's second amended complaint added facts as to investments made by prior owners in the 1950s and 1960s. The court found, however, that "[t]he old wells do not give Peak a vested right to construct numerous new wells free from intervening regulation. Peak has not pointed to a prior investment relevant to its current project." *Id.* at *2. While the vested rights doctrine provides an "irrevocable right to complete construction notwithstanding an intervening change in the law," *id.* at *3 (quoting *McCarthy v. California Tahoe Reg'l Planning Agency*, 129 Cal. App. 3d 222, 230 (1982)), "[i]t does not create an unfettered right to start new construction some 60 years later," *id.*

The court's order provided Peak with one final opportunity to amend to assert a viable takings claim. *Id.* at *3. Peak timely filed a third amended complaint (TAC) on March 24, 2023, and the County has again moved to dismiss. The County's motion to dismiss the takings cause of action in Peak's TAC unsurprisingly asserts that Peak has failed to cure the deficiencies identified by the court's multiple previous orders. *See* Motion to Dismiss First Cause of Action in Peak's Third Amended Complaint, *Peak Oil Holdings LLC v. Cnty. of Ventura*, No. 2:21-cv-00734 (C.D. Cal. Apr. 28, 2023). The County notes that the court has already found Peak does not have a vested right in its 2012 zoning clearance and does not have a vested right in the CUP to drill new wells based on previous owners' old wells, and further emphasizes that Peak's TAC only adds legal contentions to its allegations, not facts supporting a vested property right. The County acknowledges that Peak's TAC adds allegations concerning "the oil drilling process and expense . . . . In essence, Peak seems to be alleging that the oil extraction operation functioned as if it were one ongoing construction project," but argues these are legal arguments and not facts, and again notes that the court has already determined Peak derived no vested right from its predecessors. *Id.* at 14. Finally, the County argues Peak has similarly failed to allege that the County interfered with or took any action against Peak's oil and gas lease that may support a taking. *Id.* at 17.

Per the court's February 23 order, if the court finds that Peak has failed to cure the deficiencies identified in its TAC, dismissal will be without leave to amend as to Peak's takings claim, and the litigation will proceed on Peak's Fourteenth Amendment due process claim.

CalGEM Sued over Failure to Process Application for Underground Injection Project

San Joaquin Facilities Management (SJFM)—an operator at the Fruitvale Oil Field—recently sued the California Department of Conservation's Geologic Energy Management Division (CalGEM) in Kern County Superior Court for its failure to process and approve the operator's application for an underground injection project at the oil field. *San Joaquin Facilities Mgmt v. CalGEM*, No. BCV-23-100065 (Cal. Super. Ct. Jan. 5, 2023). In its first amended complaint and petition (FAC), filed February 9, 2023, SJFM asserts that the proposed project has no potential for a substantial environmental impact and must be deemed exempt from the California Environmental Quality Act (CEQA) because the project will simply shift current injection operations to a deeper formation. The pleading asserts the project will take "injectate currently being injected into existing injection wells in the shallower . . . formations and mov[e] that injectate into wells injecting into the deeper" formation. First Amended Complaint and Petition ¶ 18, *San Joaquin Facilities Mgmt. v. CalGEM*, No. BCV-23-100065 (Cal. Super. Ct. Feb. 9, 2023). As a result, there will be no "substantial adverse change from the [existing] environmental baseline." *Id.* SJFM asserts the project is exempt from CEQA under a number of categorical and statutory exemptions, including for existing facilities, minor alterations to land, and as an ongoing project. *Id.* ¶¶ 19, 26, 30. Yet CalGEM has determined the project is not exempt and has ordered SJFM to perform an initial study, which SJFM believes will only stall the project. *Id.* ¶ 16. The plaintiff seeks declaratory relief that the project is exempt from CEQA and a writ of mandamus compelling CalGEM to process its application and approve the project.

CalGEM moved to dismiss and separately moved to strike portions of the FAC on April 24, 2023. *See* Mot. to Dismiss; Mot. to Strike, *San Joaquin Facilities Mgmt. v. CalGEM*, No. BCV-23-100065 (Cal. Super. Ct. Apr. 24, 2023). Therein, CalGEM asserts that SJFM has failed to identify any actual controversy as to legal rights. Moreover, declaratory relief is not the proper review of a discretionary decision of an agency; rather, CalGEM's discretionary decision that the project is not exempt from CEQA is reviewable for abuse of discretion only. As to the petition for writ of mandate, CalGEM argues SJFM fails to state a claim because CalGEM's decision was discretionary, not ministerial, and the pleading demonstrates that there was a reasonable basis for CalGEM to find that the project is not exempt.

CalGEM's motion to strike similarly takes the position that declaratory relief is not an available remedy for review of an agency determination and so should be stricken from the FAC. Likewise, the motion argues that a court does not have authority to direct the outcome of an agency's discretionary act and, as a result, SJFM's request that the court find the project exempt and compel CalGEM to approve the project should also be stricken. Finally, CalGEM seeks to strike SJFM's requests for damages and attorney's fees as improper. CalGEM asserts that the only appropriate remedy—if it is found CalGEM abused its discretion—is for the court to remand the matter back to CalGEM.

LOUISIANA – OIL & GAS

Cristian Soler, Kathryn Gonski & Court VanTassell, Reporters

U.S. Supreme Court Rejects Appeal by Defendant Energy Companies in Louisiana Coastal Land Loss Cases

The U.S. Supreme Court declined to hear an appeal by defendant energy companies in which they argued that a lawsuit involving claims for coastal land loss in Louisiana should be removed to federal court. *See Plaquemines Parish v. Chevron USA, Inc.*, No. 22-30055, 2022 WL 9914869 (5th Cir. Oct. 17, 2022), *petition for cert. denied*, 143 S. Ct. 991 (2023) (mem.). The February 27, 2023, denial of the petition for writ of certiorari filed by petitioners-defendants Chevron U.S.A., Inc., Exxon Mobil Corp., and ConocoPhillips Company did not contain reasons for its denial, but said that Supreme Court Justice Samuel Alito "took no part in the consideration or decision of this petition."

The jurisdictional, appellate journey began when the energy companies removed the lawsuit (and several others) to federal court based on federal officer jurisdiction, 28 U.S.C. § 1442. The companies principally argued that the plaintiffs' claims were based on federally-overseen oil and gas operations that were conducted during, and on behalf of, the World War II effort. Therefore, such uniquely federal interests and the special relationship between the federal government and oil and gas industry required the cases to be heard in federal court. In early 2022, the late District Judge Martin L.C. Feldman of the U.S. District Court for the Eastern District of Louisiana held that defendants were not "acting under" federal officers to allow these cases to be heard in federal court.

The most recent decision by the highest court effectively upholds an October 17, 2022, decision by a three-judge panel of the U.S. Court of Appeals for the Fifth Circuit, which affirmed Judge Feldman's ruling and returned the cases to state court. *See* Vol. 40, No. 1 (2023); Vol. 39, No. 4 (2022) of this *Newsletter*. Additionally, this decision seemingly paves the way for 42 similar lawsuits filed in Plaquemines, Jefferson, St. Bernard, St. John the Baptist, Vermilion, and Cameron parishes to proceed in state courts.

Activists File Environmental Justice Lawsuit Against St. James Parish, Local Government

On March 21, 2023, environmental justice organizations filed a "civil rights, environmental justice, and religious liberty lawsuit" against St. James Parish, the parish council, and the parish planning commission in the U.S. District Court for the Eastern District of Louisiana in which they allege that the parish's land use policies and historical practices intentionally directed petrochemical facilities toward predominantly Black neighborhoods and away from predominantly White neighborhoods, which has resulted in racially unequal adverse health effects from pollution. *See* Complaint, *Inclusive La. v. St. James Parish*, No. 2:23-cv-00987 (E.D. La. Mar. 21, 2023), 2023 WL 2586762.

The 152-page lawsuit provides a lengthy, factual background detailing the history of slavery, Reconstruction-era failures, Jim Crow laws, the evolution of Louisiana's political system, and St. James Parish's land use system. The plaintiffs assert that this historical background and specifically the land use methods, rooted in slavery and subsequent periods of discrimination, segregation, and exploitation, have resulted in a "discriminatory and harmful land use system" in St. James Parish and the ongoing environmental and public health emergency directly threatening the plaintiffs and the majority Black residents also residing there. *Id.* ¶ 1.

Specifically, the plaintiffs allege that the parish's land use system violates various federal and state constitutional provisions and statutes, including the Thirteenth Amendment of the U.S. Constitution; the Fourteenth Amendment's equal protection and substantive due process protections, including the right to bodily safety and integrity; and 42 U.S.C. § 1982, guaranteeing the right to inherit, purchase, lease, sell, hold, and convey property.

The plaintiffs seek, among several other forms of relief, the following:

- Declaratory relief, i.e., a judgment declaring the land use approvals granted to Formosa and South Louisiana Methanol invalid (among other declaratory judgments);
- Injunctive relief, i.e., enjoining defendants from siting more industrial facilities, in particular in the 4th and 5th Districts, which are overwhelmingly majority Black;
- Order the development of a Community Engagement Process to ensure that St. James Parish residents who have been and may continue to be harmed by the defendants' land use and environmental policies and other relevant stakeholders have their interests heard and their own proposed recommendations and reforms for land use, including land use affecting cemeteries, and environmental health and safety are considered by an independent monitor and the court.
- Reasonable attorney's fees, pursuant to 42 U.S.C. § 1988;
- Costs of litigation, pursuant to 42 U.S.C. § 1988.

Sierra Club Challenges LDEQ Permits Granted to LNG Facility in Cameron Parish

Sierra Club filed two petitions asking for review of permits granted by the Louisiana Department of Environmental Quality (LDEQ) to Commonwealth LNG, LLC (Commonwealth), for the construction and operation of a natural gas liquefaction and export facility on the west side of the Calcasieu Ship Channel at its entrance to the Gulf of Mexico in Cameron Parish, Louisiana. Sierra Club filed a petition for judicial review in the 19th Judicial District Court of East Baton Rouge Parish and simultaneously filed a petition for review in the U.S. Court of Appeals for the Fifth Circuit challenging LDEQ's issuance of the same permits. *See* Petition for Review, *Sierra Club v. LDEQ* (5th Cir. Apr. 27, 2023); Petition for Judicial Review, *Sierra Club v. LDEQ* (La. Dist. Ct. Apr. 27, 2023). According to a footnote in the 19th Judicial District Court petition:

> Under the Natural Gas Act, 15 U.S.C. § 717r, the Fifth Circuit has exclusive jurisdiction over the review of any final action of a state administrative agency acting pursuant to Federal law to issue, condition, or deny any permit for the construction or operation of a liquefied natural gas facility used, among other things, to load, store, transport, gasify, liquefy, or process natural gas for export. However, Sierra Club is protectively filing this petition within the 30-day limitations period for review under La. R.S. §§ 30:2050.21(A), 2050.23(D), to preserve this Court's jurisdiction in the event the Fifth Circuit determines it does not have jurisdiction.

Petition for Judicial Review at 1 n.1, *Sierra Club v. LDEQ* (La. Dist. Ct. Apr. 27, 2023).

Sierra Club argues that LDEQ violated the federal Clean Air Act, Louisiana Environmental Quality Act (LEQA), Louisiana air regulations, and article IX, section 1 of the Louisiana Constitution in issuing these permits to Commonwealth. Among other allegations, the petition asserts that LDEQ violated the federal Clean Air Act and its public trust duty under the Louisiana Constitution by approving a permit that will result in violations of health-based National Ambient Air Quality Standards (NAAQS), 42 U.S.C. § 7409, by ignoring Commonwealth's modeled NAAQS exceedances, failing to require sufficient pollution controls, and failing to adequately account for environmental harms. As a result of these alleged violations, Sierra Club requested that the court vacate LDEQ's decision to issue the permits, remand the matter to LDEQ for further consideration, and award all other relief the court finds proper.

Pursuant to La. Stat. Ann. § 30:2050.21(C)–(D), LDEQ is not required to file an answer to the petition for review, but it must transmit to the reviewing court the original or a certified copy of the entire record of the decision or action under review within 60 days after service of the petition on the department, or within further time allowed by the court. Further, section 30:2050.21(G) provides that "[j]udicial review, appeals, and other proceedings for injunctive relief regarding environmental permits needed for construction or operation of new facilities or modification of existing facilities, shall be decided by the court summarily and by preference."

MINNESOTA – MINING

Gregory A. Fontaine, Reporter

Federal and State Actions Involving the Duluth Complex

On January 26, 2023, the U.S. Department of the Interior (DOI) issued an order under the Federal Land Policy and Management Act withdrawing approximately 225,000 acres of federal surface and mineral lands in the Superior National Forest in northeastern Minnesota from disposition under U.S. mineral and geothermal leasing laws. *See* Public Land Order No. 7917, 88 Fed. Reg. 6308 (Jan. 31, 2023). The order is subject to valid existing rights. The U.S. Forest Service had proposed the withdrawal in 2021 and various studies and other administrative activities had been proceeding since that time. The copper-nickel-platinum group metals mine proposed by Twin Metals Minnesota LLC (TMM), a subsidiary of Antofagasta PLC, is located within the area subject to DOI's order. The withdrawal area covers much of the Rainy River watershed, home to the Boundary Waters Canoe Area Wilderness (BWCAW). TMM and Franconia Minerals (US) LLC, another Antofagasta subsidiary, filed suit against the United States in August 2022 asserting, among other things, that DOI and the Bureau of Land Management violated the company's existing rights when it canceled Franconia's federal mineral leases and rejected TMM's preference right lease application. The litigation remains pending in the U.S. District Court for the District of Columbia. *See Twin*

Metals Minn. LLC v. United States, No. 1:22-cv-02506 (D.D.C. filed Aug. 22, 2022).

In a separate matter involving the Rainy River watershed, the Minnesota Department of Natural Resources (MDNR), in connection with stipulations reached in a case in Ramsey County District Court filed under the Minnesota Environmental Rights Act, *see Ne. Minnesotans v. Minn. Dep't of Nat. Res.*, No. 62-CV-20-3838 (Minn. Dist. Ct., Ramsey Cnty., May 12, 2021); *see also* Vol. XXXVIII, No. 3 (2021) of this *Newsletter*, is continuing its review of comments filed in an agency proceeding considering whether revisions should be made to the state's nonferrous mining regulations to further protect the BWCAW. Under the district court's order, a contested case hearing could follow MDNR's administrative recommendations on the nonferrous rules. MDNR's target under the district court's order for releasing its initial decision is May 31, 2023.

NorthMet and Mesaba Project Combination; Update on NorthMet Permits

On February 14, 2023, PolyMet Mining Corp. (PolyMet) and Teck American Inc. (Teck American), a subsidiary of Teck Resources Limited, closed an agreement to create a 50/50 joint venture combining their NorthMet and Mesaba projects located in Minnesota's Duluth mineral complex The Duluth complex reportedly contains some of the largest undeveloped deposits of copper, nickel, and platinum group metals in the world. The joint venture will be conducted through NewRange Copper Nickel LLC, the new name for Poly Met Mining, Inc., the former wholly-owned subsidiary of PolyMet which is now jointly owned by Teck American and PolyMet.

Myriad permits for the NorthMet project have been wending their way through various judicial and administrative challenges. Currently all but three of the approximately 20 permits issued for the project in 2018–2019 are active. A contested case hearing was held before an administrative law judge in March 2023 relating to the permit to mine previously issued by the Minnesota Department of Natural Resources (MDNR). The Minnesota Supreme Court ordered the hearing on limited issues in a 2021 opinion reversing a state court of appeals decision requiring a contested case on a much broader set of issues. *In re NorthMet Project*, 959 N.W.2d 731 (Minn. 2021); *see* Vol. XXXVIII, No. 2 (2021) of this *Newsletter*. MDNR has announced it will act on the NorthMet permit to mine after receiving the administrative law judge's recommendations in the contested case, and the agency also will separately address two other matters relating to permit to mine—how to establish a fixed permit term as required by the Minnesota Supreme Court and whether Glencore, the majority shareholder of PolyMet, should be added to the permit. *See* Bulletin, MDNR, "DNR Initiates Contested Case Hearing Process Regarding PolyMet Permit to Mine" (undated).

The Minnesota Supreme Court is also currently reviewing the water pollution control and air emissions control permits issued by the Minnesota Pollution Control Agency (MPCA) for the NorthMet project. These cases arise from appeals of Minnesota Court of Appeals decisions dismissing challenges to MPCA's reissued air permit, *see In re Issuance of Air Emissions Permit No. 13700345-101*, No. A22-0068 (Minn. Sept. 20, 2022) (order granting pet. for rev.), and upholding MPCA's water permit, *see In re Issuance of the Denial of Contests Case Hearing Requests and Issuance of NPDES/SDS Permit No. MN00771013 for the Proposed NorthMet Project*, No. A19-0112 (Minn. Apr. 19, 2022) (order granting pet. for rev.), except for an issue required to be reconsidered by the agency in light of a U.S. Supreme Court Clean Water Act decision after the agency's issuance of the water permit. *See Cnty. of Maui v. Haw. Wildlife Fund*, 140 S. Ct. 1462 (2020) (interpreting NPDES permit requirements under the federal Clean Water Act).

Talon Announces Intent to Begin Environmental Review and Permitting on Nickel Project

In April 2023, Talon Metals Corp. (Talon), in connection with detailed information releases on the status of exploration and development activities involving its Tamarack nickel project, announced that its 2023 corporate objectives include beginning the environmental review and permitting process for its planned underground mine and rail load out facility in central Minnesota. *See* https://talonmetals.com/corporate-presentations/. Talon also plans to construct a processing facility in North Dakota in association with the Minnesota mine. Talon is the majority owner and operator of the Tamarack nickel project as part of a joint venture with Rio Tinto.

MDNR Recommends Awarding State Iron Ore Leases to Cleveland-Cliffs

The saga to repurpose the former Butler Taconite operations near Nashwauk on the Minnesota Iron Range is moving forward again. In the last few years, several mining companies have been competing to secure state mineral leases at the Nashwauk site for use in different iron mining operations. On May 4, 2023, the Minnesota Department of Natural Resources (MDNR) announced that it is recommending that these state mineral leases for iron ore resources be awarded to Cleveland-Cliffs Inc. (Cleveland-Cliffs). The leases were most recently held by Mesabi Metallics Company, LLC (Mesabi Metallics), in connection with its multi-year efforts to construct an iron ore mine and processing facility at the former Butler Taconite site.

The Mesabi Metallics project is partially completed. Although the company has not abandoned its efforts, it lost its state mineral leases when MDNR terminated them after the company failed to meet a 2021 deadline for a $200 million funding obligation relating to the leases. Mesabi Metallics subsequently commenced a lawsuit challenging MDNR's termination of the state leases, but that litigation has been unsuccessful.

On January 17, 2023, the Minnesota Supreme Court denied Mesabi Metallics' petition for review of the decision by the state court of appeals upholding MDNR's lease termination. *Mesabi Metallics Co. v. Minn. Dep't of Nat. Res.*, No. A22-0410 (Minn. Jan. 17, 2023) (order denying pet. for rev.). Since the termination, multiple companies have approached MDNR expressing interest in the state mineral holdings. There are also numerous private mineral holdings adjacent to and near the state mineral lands.

Cleveland-Cliffs has indicated it wants to secure the Nashwauk-area state leases for use in connection with the Hibbing Taconite operations it jointly owns with U.S. Steel. But U.S. Steel has been separately seeking to acquire the state leases for an alternative use. Cleveland-Cliffs and U.S. Steel currently own all of the operating taconite mines and facilities in Minnesota. Mesabi Metallics and its parent company, Essar Group, have continued to state publicly that they wish to complete the project that they have been pursuing but which has been largely stalled for various reasons, including bankruptcy proceedings involving Mesabi Metallics, then under different ownership, that were initiated in 2016.

In its May 4 announcement, MDNR stated it intends to bring to the State of Minnesota's Executive Council in the near future the agency's recommendation to award the state leases to Cleveland-Cliffs. Under Minnesota law, the Executive Council will be responsible for a final decision with regard to the party to which the state leases will be awarded and the relevant terms and conditions of the leases. The Executive Council consists of the Governor and the four other statewide elected officers under the Minnesota Constitution. It would not be surprising if there are more twists and turns before these leasing decisions are fully sorted out.

Editor's Note: The reporter's law firm represents clients in some of the matters discussed in this report.

NEVADA – MINING

Thomas P. Erwin, Reporter

Mining Bills Introduced in Nevada Assembly

The Nevada Legislature commenced its 82nd Session on February 2, 2023. Two bills affecting the mining industry—Assembly Bill 204 (AB 204) and Assembly Bill 313 (AB 313)—have been introduced.

Assembly Bill 204 provides that (1) a mill site may be located on a previously located mining claim if the mineral character of the land has not yet been determined, and (2) the locator of the mill site may hold a certificate of location for the mining claim and a certificate of location for the mill site that includes the same land. The assembly has not yet voted on AB 204. AB 204 may run afoul of the U.S. General Mining Law, which allows mill sites only on "nonmineral land not contiguous to the vein or lode." 30 U.S.C. § 42.

Assembly Bill 313 provides that if an open pit mine will be excavated below the pre-mining water table, a plan for reclamation must provide for the backfilling of the open pit to a level where no pit lake will form and no seasonal or permanent wetland will exist. The bill also provides that an operator of a mining operation may apply to the Division of Environmental Protection (Division) of the State Department of Conservation and Natural Resources for an exception to the requirement of subsection 1. In submitting an application for an exception, the operator must demonstrate: (1) for an application for a permit to engage in a operation submitted on or after January 1, 2025, by clear and convincing evidence that backfilling the open pit is technically not possible without indefinite long-term management to avoid groundwater degradation; or (2) by a preponderance of the evidence, that backfilling the open pit would result in undue hardship on the operator because the plan for the mining operation would be unprofitable. The Division must hold at least one public hearing on the application for the exception.

OKLAHOMA – OIL & GAS

James C.T. Hardwick & Pamela S. Anderson, Reporters

"Cessation-of-Production" Clause Does Not Establish the Time Period for Assessing Whether Cessation of Production in Paying Quantities Occurred

In *Tres C, LLC v. Raker Resources, LLC,* 2023 OK 13, 2023 WL 1990113, the Oklahoma Supreme Court granted certiorari to address whether the trial court erred in analyzing only a three-month window of time for assessing whether a dip in the subject well's production was a cessation of paying quantities, such that the lease of the defendants, Raker Resources, LLC (Raker), Continental Resources, Inc. (Continental), and DewBlaine Energy, LLC (DewBlaine), expired by its own terms.

The lease at issue (Cowan Lease) contained a cessation-of-production clause providing that if, after the expiration of the primary term, production on the leased premises should "cease from any cause," the lease would not terminate if the lessee resumed operations for drilling within 60 days from such cessation. *Id.* ¶ 2. The well at issue (Cowan Well) produced oil and gas in paying quantities after its completion in 1965, and the Cowan Lease moved into the secondary term defined by the habendum clause shortly thereafter. *Id.*

The defendants were the successors-in-interest under the Cowan Lease. *Id.* ¶ 3. Raker was the operator of the Cowan Well, and the well produced normally until early 2016. At that time the plaintiff, Tres C, LLC (Tres C), began receiving only sporadic royalty checks from Raker. Tres C, through its lawyers, thereafter made a demand to Raker that Raker, inter alia, release the Cowan Lease, because "the relevant production records . . . evidence that the GD Cowan No. 1 well has long since ceased producing in paying quantities . . . [and that] the captioned Lease has expired by its terms." *Id.* ¶ 5 (alteration in original). At counsel's request, Raker sent documents to Tres C's counsel that showed that a dip in production during December 2015 had been unprofitable. *Id.*

After that dip, the Cowan Well became profitable, but only slightly. In January 2016, it began producing some fluid, and in May 2016 it began experiencing occasional pressure spikes. Then in September 2016, the Cowan Well experienced another month of low production and unprofitability, and failed to produce anything on October 14 and 15, 2016, due to line pressure issues. *Id.* ¶ 6.

Raker was proactive in trying to remedy the production problems, including "using more soap" in an attempt to aerate the fluid and make it easier to expel; "'rocking the well' back and forth" between the coil tubing and the annulus to force the fluid up; and moving a compressor from a nearby well to the Cowan Well in hopes that it would help draw the fluid out of the wellbore. *Id.* ¶ 7. The Cowan Well thereafter produced profitably for a time. *Id.* Nevertheless, the line pressure jumped again in mid-November 2016; the compressor never succeeded in drawing any fluid up out of the wellbore; and ultimately, October, November, and December 2016 proved to be unprofitable for the Cowan Well. *Id.* ¶ 8.

In the meantime, on November 14, 2016, Tres C entered into a lease option agreement with J&R Energy Resources, LLC (J&R), whereby J&R would fund legal proceedings to secure the termination of the Cowan Lease in exchange for Tres C's promise to give J&R an exclusive option to file a top lease at a later date. *Id.* ¶ 9. J&R's counsel then contacted DewBlaine and Raker threatening litigation to terminate the Cowan Lease. *Id.* Raker informed Continental of the communications as well as the status of the Cowan Well, and inquired whether Continental would be willing to accept an assignment of 3% of Raker's 7.5% overriding royalty interest in the Cowan Lease in exchange for Continental spudding a new well on the lease before January 31, 2017. *Id.*

Continental eventually accepted Raker's offer and made plans to spud a new well in late January 2017. *Id.* ¶¶ 10, 11. Nonetheless, because of various objections filed by J&R's counsel with the Oklahoma Corporation Commission (OCC), the new well was not completed until July 29, 2017. *Id.* ¶¶ 11, 12.

However, having seen where things were going at the OCC, J&R's counsel, on February 27, 2017, filed an equitable action to quiet title on Tres C's behalf, alleging that the Cowan Well had ceased to produce in paying quantities, and that the Cowan

Lease had expired by its own terms. *Id.* ¶ 13. At trial, Tres C presented evidence that the Cowan Well failed to produce in paying quantities in September, October, and November 2016. *Id.* ¶ 15. The defendants put on evidence, inter alia, that the three-month period analyzed by Tres C's expert was not adequate for determining whether the Cowan Well had, in fact, become unprofitable. *Id.* ¶ 16.

The trial court quieted title and entered judgment in favor of Tres C, finding that the "'Cowan Well failed to produce in paying quantities for the production months of September, October and November of 2016,'" and alternatively, that the Cowan Well was shut in on October 17, 2016, after two days of no production, and that cessation of production occurred because the well was not producing in paying quantities immediately prior to being shut in. *Id.* ¶ 18. Having two bases for cessation of production, the trial court further found that Raker "did not restore production in paying quantities from the Cowan Lease within the 60 day grace period provided by the Cessation of Production Clause," and that Continental "did not commence operations for the drilling of a new well on the Subject Lease during the grace period . . . in time to perpetuate the Subject Lease under the terms of the Cessation of Production Clause," because Continental had not begun moving dirt for the building of its new well until January 19, 2017. *Id.*

On appeal, the defendants argued that the trial court (1) erroneously held that "production" ceases any moment that profitability is interrupted, instead of analyzing profitability over a reasonable accounting period; and (2) failed to address whether the plaintiff's demand for release of the Cowan Lease in March 2016 and/or November 2016 accompanied by a recorded top lease would permit the defendants to take advantage of the "obstruction doctrine" by suspending operations and relieving them of the duty to produce in paying quantities until resolution of the title challenge. *Id.* ¶ 19.

In its June 8, 2021, opinion, the Oklahoma Court of Civil Appeals did not reach the cessation issue raised by the defendants, because the defendants had stated they were not challenging any factual determinations made by the trial court, only the legal standard applied by that court, and the court of appeals treated the trial court's finding of cessation of production in paying quantities as a factual finding. *Id.* ¶ 20. Because the obstruction defense had not been addressed by the trial court, the court of appeals remanded to the trial court to rule on that defense, but "conditionally affirmed" the trial court judgment contingent upon the trial court finding against the defendants on the obstruction defense. *Id.*

The defendants filed their petition for writ of certiorari to the Oklahoma Supreme Court on June 25, 2021. *Id.* ¶ 21. In its February 14, 2023, opinion, the Oklahoma Supreme Court found the issue for determination was "whether it was legal error for the trial court to apply a rule of law that analyzed only a 3-month window of time for assessing whether the Cowan Well had experienced a cessation of production in paying quantities such that the Cowan Lease expired by its own terms." *Id.* ¶ 23. In other words, "the issue concerns *how* to determine whether production that maintains a gas lease under the habendum clause has ceased, including whether the cessation-of-production clause plays any role in narrowing the window of time that should be considered in making such a determination." *Id.*

The defendants claimed the Cowan Well should have been assessed "over a reasonable look-back period of time sufficient to consider whether a prudent operator would continue or abandon operations." *Id.* ¶ 24. They contended that the 60-day savings period in the cessation-of-production clause does not come to bear until a longer look-back period (gauged in light of the equitable circumstances) "demonstrates that a *cessation*—not merely an *interruption*—of profitable production has occurred." *Id.* Otherwise, the savings period of the cessation clause would always be engaged, and the lessee would have to constantly evaluate the need to commence a new well to save the lease upon every interruption of profitable production, as well as monitor production on a daily basis to be prepared to take action if production from any single day resulted in loss. *Id.* The plaintiff, however, argued that the Cowan Lease's bargained-for cessation-of-production clause controlled over the common law temporary cessation doctrine to give the defendants only 60 days to restore production in paying quantities. *Id.* ¶ 25.

The court found that the trial court erred in determining that cessation of production occurred based upon the plaintiff's evidence that the Cowan Well was unprofitable for three months; but that even if all the evidence showed that the well was operating at a loss during those three months, that period of time, *as a matter of law*, was too short for determining whether a cessation of production in paying quantities had occurred. *Id.* ¶ 26.

First, the court noted it had repeatedly explained that the cessation-of-production clause is only implicated where production had *already ceased* (i.e., *after* a cessation has occurred), and repeatedly characterized the cessation clause as a "savings clause" that defines the grace period for reestablishing production in paying quantities through the means specified (e.g., commencement of drilling operations for a new well, commencement of operations to rework an old well). *Id.* ¶ 28. Thus, the cessation-of-production clause kicks in *after* a cessation has occurred that could result in termination of a lease under the habendum clause, and gives the operator an extension of time for preserving the lease through the means set forth in the cessation clause. As such, the cessation-of-production clause and the 60-day period contained therein has no bearing on anything that is done *before* cessation occurs, including assessment of whether a cessation has occurred. *Id.*

Second, the court agreed with the defendants and their cited treatise that it is not the purpose of the cessation-of-production clause to establish an accounting period for purposes of determining if production is in paying quantities. *Id.* ¶ 29. Otherwise, operators subject to the 60-day cessation clause would be required to commence drilling operations immediately upon sustaining a slight loss for a month, without regard for whether they believed the next month's production might be profitable, because another month of slight loss could result in forfeiture of the lease. *Id.* "Such a result would be wholly unworkable in the oil and gas industry." *Id.* Further, if the court used the cessation-of-production clause to establish a three-month accounting period, the court would "indubitably burden leasehold operators with a duty to *market continually* in order to maintain the profitable production necessary to sustain the lease"—a duty that the court expressly rejected in *Pack v. Santa Fe Minerals*, 869 P.2d 323, 327–28 (Okla. 1994). *Tres C*, 2023 OK 13, ¶ 29. The court stated that, "in order to avoid unwanted results, we must steer clear of using the cessation-of-production clause to define a specific accounting period for determining whether production has been in paying quantities." *Id.*

Instead, case law provides that when an appellate court is reviewing whether "the period employed by the trial court to determine profitability was sufficient," "the appropriate time period is not measured in days, weeks or months, but by a time appropriate under all the facts and circumstances of each case." *Id.* ¶ 30 (quoting *Barby v. Singer*, 648 P.2d 14, 16–17 (Okla. 1982)). The court noted it had repeatedly approved use of "reasonably lengthy accounting periods in assessing profitability of a well's production." *Id.* In *Barby*, the court approved use of a 14-month period; in *Smith v. Marshall*, 2004 OK 10, 85 P.3d 830, the court found a three-year period was sufficient under all the facts and circumstances; and in *Henry v. Clay*, 274 P.2d 545 (Okla. 1954), the court considered the subject well's production over a 32-month period. *Tres C*, 2023 OK 13, ¶ 30.

The plaintiff argued that language from the court's opinions in *Hoyt v. Continental Oil Co.*, 606 P.2d 560 (Okla. 1980), *French v. Tenneco Oil Co.*, 725 P.2d 275 (Okla. 1986), and *Hall v. Galmor*, 2018 OK 59, 427 P.3d 1052, mandated that the time period in the cessation-of-production clause overrides the common law requirement to utilize a "reasonable" time period. *Tres C*, 2023 OK 13, ¶ 31. The court, however, found that Tres C improperly assumed that the "reasonable amount of time" permitted under the temporary cessation doctrine encompassed *both* the period of time the court would look at to assess whether a cessation occurred, *and* the period of time allowed for resumption of operations *after* the cessation occurred. *Id.* Thus, Tres C wanted the court "to recognize the cessation-of-production clause as a substitute for *both* periods of time, thereby limiting the period of time for assessing profitability to 60 days and, in the event such circumscribed data demonstrates unprofitability, leaving no time for resumption of drilling operations." *Id.* The court rejected this argument for three reasons.

First, the court found that the language quoted by the plaintiff from *Hoyt*, *French*, and *Hall* undermined the plaintiff's position insofar as it discusses the time for "resumption of drilling operations" or for "restoration of production." *Id.* ¶ 33. That language "clearly presupposes that cessation has already occurred; otherwise, there is no need to resume drilling or reworking." *Id.*

> [B]oth the cessation-of-production clause *and the temporary cessation doctrine* only come into play *after* a cessation has occurred. The name of the doctrine also bolsters the notion that it is triggered by a "cessation," albeit it a "temporary" one. Thus, neither the cessation-of-production clause nor the temporary cessation doctrine have anything to do with the reasonable time period that governs the pre-cessation assessment of profitability.

Id.

Second, the court found that, despite the plaintiff's language from *Hoyt*, *French*, and *Hall*, "the cessation-of-production clause was never designed to eliminate or avoid the operation of the temporary cessation doctrine," as the plaintiff argued. *Id.* ¶ 34. The court cited extensively from a leading treatise on oil and gas law, quoting:

> The doctrine of temporary cessation of production is a practical necessity, because oil and gas are never produced and marketed in a continuous, uninterrupted operation that goes on every hour of the day and night. Once it is recognized that any brief interruption in the operation must be tolerated as a practical matter, it becomes necessary to adopt a doctrine that permits temporary cessations of production. *The* [*cessation-of-production*] *clause . . . was never designed to eliminate or to avoid the operation of such doctrine or to require that oil or gas be produced and marketed in a continuous, uninterrupted operation. It was intended to preserve a lease in order to permit a lessee to restore production if production should cease under circumstances that require drilling or reworking on his part in order to restore production. Accordingly, it would be more reasonable to construe the . . . clause so that the clause "or if after the discovery of oil or gas in paying quantities, the production thereof should cease from any cause" refers not to the temporary cessation of production, but to a cessation of production that would be permanent unless corrected by reworking or drilling operations.*

Id. (quoting 2 Eugene Kuntz, *A Treatise on the Law of Oil and Gas* § 26.13(b) (2021)).

In the case of *Tres C*, the court noted that "the event which can prevent termination under the Cowan Lease's cessation-of-production clause is the 'resum[ption of] *operations for drilling a well* within sixty (60) days from such cessation.'" *Id.* (alteration in original). "This indicates that the parties intended the clause to become operative only if the 'cessation' was permanent, as only a permanent cessation would require the remedy of drilling a new well." *Id.* The court thus rejected the plaintiff's argument that a temporary cessation (such as Raker's testing whether the Cowan Well's pressure and fluid build-up problems could be remedied by installation of a compressor or the downhole utilization of more soap) should trigger the 60-day time limit in the cessation-of-production clause, particularly insofar as the clause was "designed to provide a grace period for protecting [the defendants'] leasehold interests, and in light of the strong policy of our statutory law against forfeiture of estates . . . ." *Id.* (citation omitted). Moreover, the court found, even if the rule requiring a "reasonable time period" for determining profitability did emanate from the temporary cessation doctrine (which the court denied), "the cessation-of-production clause's 60-day time limit need not serve as a basis for elimination or avoiding the reasonable time period." *Id.*

Lastly, the court found the plaintiff's reliance on *Hoyt* and *French* was misguided "insofar as this Court has previously distinguished those cases in a way that limits their applicability to situations where the subject wells are incapable of producing when the primary terms of the lease expires and are thus unable to produce during the secondary term." *Id.* ¶ 35. Since the Cowan Well was producing far into the secondary term, the court held those cases inapposite. *Id.*

In conclusion, the court found that, had the trial court "applied the appropriate rule of law and analyzed the Cowan Well's profitability over 'a time [period] appropriate under all of the facts and circumstances,' judgment should have been entered in favor of [the defendants] by reason of [the plaintiff's] failure to carry their burden of proof," *id.* ¶ 37 (first alteration in original) (quoting *Barby*, 648 P.2d at 16–17), because "three months is not an appropriate time period under all the facts and circumstances of this case, particularly in light of the operator's efforts to remedy the dip in production," *id.*

In addition, the court found the trial court's judgment arose from "its back-dating the erroneously found cessation to September 1, 2016, which effectively served to deprive [the defendants] of the 60-day grace period afforded in the cessation-of-production clause." *Id.* (footnote omitted). Instead, "[a]ny cessation would have commenced on December 1, 2016, at the close of the three-month period used to assess profitability," and Continental's commencement of drilling operations on January 19, 2017, "would have maintained the Cowan Lease under the cessation-of-production clause." *Id.* The court noted that

> [d]espite the fact that the cessation-of-production clause has no bearing on the accounting period, the facts of this case demonstrate that the goal of that clause was realized when [Continental] drilled a more productive well. Production benefits the operator ([Continental]), the overriding royalty owner ([Raker]), and the royalty owner (Tres C); and that goal has been accomplished.

Id. The court therefore vacated the court of appeals' opinion, reversed the trial court's judgment, and quieted title in favor of the defendants. *Id.*

Subsequent to the rendition of the court's opinion, Tres C filed for rehearing. As of the date of this report, Tres C's petition for rehearing remains pending. Thus, the foregoing opinion is not final.

PENNSYLVANIA – MINING

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

The Future of Pennsylvania's RGGI Rule Remains Uncertain

As previously reported in Vol. 39, No. 2 (2022) of this *Newsletter*, the Pennsylvania Department of Environmental Protection's (PADEP) CO_2 Budget Trading Program rule, or RGGI Rule, which links the commonwealth's cap-and-trade program to RGGI, was published in the *Pennsylvania Bulletin* in April 2022. *See* 52 Pa. Bull. 2471 (Apr. 23, 2022). RGGI is the country's first regional, market-based cap-and-trade program designed to reduce carbon dioxide (CO_2) emissions from fossil fuel-fired electric power generators with a capacity of 25 megawatts or greater that send more than 10% of their annual gross generation to the electric grid.

Three legal challenges were filed in response to the publication of the final rule. On April 25, 2022, owners of coal-fired power plants and other stakeholders filed a petition for review and an application for special relief in the form of a temporary injunction, which was granted. *See Bowfin KeyCon Holdings, LLC v. PADEP*, No. 247 MD 2022 (Pa. Commw. Ct. filed Apr. 25, 2022); Vol. 39, No. 3 (2022) of this *Newsletter*. Briefing has been filed and the court heard 30 minutes of oral argument in the case on November 16, 2022. On March 24, 2023, the Supreme Court of Pennsylvania granted requests to dismiss the preliminary injunction because the petitioners had failed to pay the bond required to secure the preliminary injunction. Petitioner Bowfin KeyCon Holdings, LLC, which has an interest in some of the subject coal-fired power plants, filed an appeal of the bond amount in summer 2022, claiming that the bond was infeasible or impossible to pay and asked the court to reduce it to a negligible amount. Despite the end of the preliminary injunction, the court may still make a decision on the merits in the coming months.

The acting Secretary of PADEP filed suit in the Pennsylvania Commonwealth Court against the Pennsylvania Legislative Reference Bureau (Bureau) in February 2022, seeking to compel the Bureau to publish the Environmental Quality Board's final-form rulemaking for the CO_2 Budget Trading Program in the *Pennsylvania Bulletin*. *See McDonnell v. Pa. Legis. Reference Bureau*, No. 41 MD 2022 (Pa. Commw. Ct. filed Feb. 3, 2022). By law, the House and Senate each have 30 calendar days or 10 legislative days—whichever is longer—to vote on a disapproval resolution to stop a new rule from taking effect. PADEP argued that the periods should have run simultaneously for the House and Senate, rather than one after the other, and the Bureau's improper interpretation delayed issuance of the rule. On January 19, 2023, the commonwealth court dismissed the case as moot, as the rule was published in April 2022, without ruling on the merits. *See* Vol. 40, No. 1 (2023) of this *Newsletter*.

Additionally, on July 13, 2022, natural gas companies Calpine Corp., Tenaska Westmoreland Management LLC, and Fairless Energy LLC filed a third legal challenge to the rule with arguments similar to those brought in the other two cases. *See Calpine Corp. v. PADEP*, No. 357 MD 2022 (Pa. Commw. Ct. filed July 12, 2022). Constellation Energy Corporation and Constellation Energy Generation LLC petitioned to intervene in the case, but later filed a joint motion to stay intervention proceedings on October 31, 2022, which the court granted. The stay on the application for intervention remains in place. Briefing in this case has been filed and oral argument was heard on February 8, 2023. This case is still pending.

The state's future plans for its RGGI regulation remain unclear, but it is unlikely to take action prior to a decision on the merits in the two remaining pending cases. Further information regarding the rule and the history of the rulemaking can be found on PADEP's RGGI webpage at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

PADEP Holds Public Meetings Regarding Climate Action for Environmental Justice Communities

In April 2023, the Pennsylvania Department of Environmental Protection's (PADEP) Energy Programs Office, local partners, and its contractor, Preservation Design Partnership, hosted meetings with leaders and residents of environmental justice (EJ) communities around the state. The meetings were intended as listening sessions to learn how PADEP can assist Pennsylvania's EJ communities become more sustainable and prepare for the effects of climate change. The meetings also provided information on the Energy Programs Office's Climate Action for Environmental Justice Communities Program and provided information on additional available resources. Sessions were held in Meadville, Pittsburgh, Scranton, Reading, Harrisburg, Norristown, and Philadelphia, and also provided for virtual attendance. Discussions covered a wide range of topics including fuel source strategies, land use regulations and building codes, infrastructure, and public health.

During its Philadelphia session, the Energy Programs Office representative indicated that PADEP plans to be more intentional about the inclusion of EJ in the Pennsylvania Climate Action Plan, which is updated every three years (the last update was released in 2021). In addition, what they learn from the meetings will inform other program development, such as grants. Lastly, the Energy Programs Office plans to incorporate community feedback from the meetings in the Guide to Climate Action for Environmental Justice Communities that is currently under development. The guide is intended to inform PADEP's climate action planning to ensure that strategies produce meaningful benefits in EJ communities and adequately prioritize state and federal funding. PADEP anticipates releasing the guide in summer 2023.

Pennsylvania Supreme Court Remands EHB Fees Case

On February 22, 2023, the Pennsylvania Supreme Court vacated and remanded a Pennsylvania Commonwealth Court decision affirming the Environmental Hearing Board's (EHB) denial of legal fees to parties challenging environmental permits issued by the Pennsylvania Department of Environmental Protection (PADEP). Clean Air Council v. PADEP, Nos. 73 MAP 2021, 74 MAP 2021, slip op. (Pa. Feb. 22, 2023). In separate suits, environmental groups and landowners challenged permits issued to Sunoco Pipeline, L.P., for the Mariner East 2 pipeline and later sued for legal fees. The EHB ruled that the environmental groups and landowners could not compel reimbursement of their legal fees because such reimbursement is allowed only in cases in which a party's bad faith in challenging or defending a PADEP permit is established and no such bad faith occurred. The commonwealth court affirmed. The supreme court disagreed, concluding that the bad-faith standard was incompatible with the Pennsylvania Clean Streams Law and that the EHB has taken an overbroad reading of applicable case law to support its position.

Section 307(b) of the Clean Streams Law, 35 Pa. Stat. § 691.307(b), provides that upon the request of any party, the EHB "may in its discretion order the payment of costs and attorney's fees it determines to have been reasonably incurred by such party in proceedings pursuant to this act." The supreme court concluded that the Clean Streams Law "neither limits nor guides the [EHB's] discretion," but that the EHB has "opted on its own to cabin that discretion." *Clean Air Council*, slip op. at 2. It is possible that the supreme court's decision could result in permittees not only paying to defend legal challenges to their permits, but also paying the legal expenses incurred by the parties challenging their permits. It is yet to be seen, however, how the EHB will apply the supreme court's decision.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart, Sean M. McGovern, Matthew C. Wood & Christina M. Puhnaty, Reporters

In Response to Environmental Groups' Request, PADEP Declines to Issue Order to Shell Plant to Cease Operations

On February 17, 2023, the Clean Air Council (CAC) and the Environmental Integrity Project (EIP) sent a letter to the Pennsylvania Department of Environmental Protection (PADEP) requesting that the agency issue an order to Shell Chemical Appalachia LLC (Shell) to temporarily halt operations at the Shell Polymers Monaca Plant in Beaver County, Pennsylvania (Plant). *See* Letter from EIP & CAC to PADEP (Feb. 17, 2023). Specifically, CAC and EIP alleged that people living near the Plant had been exposed to volatile organic compounds (VOCs), nitrogen oxide (NOx), and other pollutants emitted in violation of Shell's plan approval, the federal Clean Air Act, and the Pennsylvania Air Pollution Control Act (APCA). CAC and EIP cited PADEP's February 2023 notice of violation (NOV) documenting the Plant's exceedances of the 12-month rolling total emission limitations for VOCs in November and December 2022 and the 12-month rolling total emission limitations for NOx in December 2022, as well as the agency's December 2022 NOV for the same VOCs emissions violations during September and October 2022. CAC and EIP also highlighted multiple malfunction reports submitted to PADEP by Shell documenting alleged violations of the visible emissions limitations of the Clean Air Act and Shell's plan approval related to emissions from the Plant's flares.

CAC and EIP urged PADEP to immediately act using the authority granted to it under the APCA, arguing that the statute allows the agency to issue orders to facilities to cease operations in violation of the APCA, plan approvals, or permits, citing as precedent a stop construction order PADEP issued in 2018 related to incidents during the construction of the Mariner East 2 pipeline. CAC and EIP requested that PADEP issue a similar order to Shell until the company can demonstrate that the Plant can operate in compliance with applicable laws. Prior to submitting their request to PADEP, CAC and EIP also sent Shell a notice of intent to sue the company under the citizen suit provisions of the Clean Air Act and the APCA to compel the Plant's compliance with applicable requirements. *See* Notice of Intent to Sue (Feb. 2, 2023).

PADEP responded to CAC and EIP's allegations in a February 28, 2023, letter in which the agency declined to issue an order to Shell, citing ongoing evaluations and inquiries, but said it would consider CAC and EIP's letter in evaluating future enforcement actions. *See* PADEP Response (Feb. 28, 2023). The agency explained that according to Shell, the Plant is still in the commissioning phase, which started in mid-2022, and Shell has represented that the malfunctions and violations during commissioning will not occur during normal operations. PADEP also noted that it had fined Shell, was considering other penalties, and directed Shell to submit an emission exceedance report and mitigation plan examining the causes of, and identifying measures to prevent, the violations and malfunctions, which Shell did on January 30, 2023. Since then, PADEP requested, and Shell provided, additional technical information regarding the mitigation plan. PADEP has also issued Shell four more NOVs and Shell has submitted another malfunction report. For additional information, see https://www.dep.pa.gov/About/Regional/SouthwestRegion/Community%20Information/Pages/Shell-Petrochemical-Complex-.aspx.

Pennsylvania PUC Denies Petition to Reconsider Jurisdiction over Certain Class 1 Gathering Pipelines

On March 16, 2023, the Pennsylvania Public Utility Commission (PUC) entered an order (Order) denying a petition for reconsideration (Petition) of its December 8, 2022, implementation order (Implementation Order), under which the PUC asserted jurisdiction over Class 1 natural gas gathering pipelines, including Type R intrastate pipelines, and certain liquid natural gas facilities. To reach this conclusion, the PUC relied on the Gas and Hazardous Liquids Pipelines Act (Act 127), 58 Pa. Stat. §§ 801.101–.1101, and amendments to regulations made in the final Gas Gathering Rule of the Pipeline and Hazardous Materials Safety Administration (PHMSA), 86 Fed. Reg. 63,266 (Nov. 15, 2021) (to be codified at 49 C.F.R. pts. 191, 192). As described in the Implementation Order, the PUC determined that Type R lines were subject to Act 127 registration and assessment, meaning that as issued, the Implementation Order would have required operators of Type R lines to register with the PUC on an annual basis and pay annual assessments.

In its Petition, the Pennsylvania Independent Oil & Gas Association (PIOGA), a trade association representing Pennsylvania oil and natural gas interests, challenged the PUC's conclusion. It argued that the PUC had committed an error of law because Type R lines are subject only to annual and incident reporting requirements under 49 C.F.R. Part 191, which governs annual, incident, and other reporting requirements, but not subject to safety requirements under 49 C.F.R. Part 192, which governs minimum federal safety standards. PIOGA contended that because Type R lines are not subject to the Part 192 safety regulations, they do not implicate the PUC's pipeline safety program. As such, the PUC lacked jurisdiction under Act 127, with its accompanying registration and annual assessment requirements, which apply only to "pipelines, pipeline operators or pipeline facilities regulated under Federal pipeline safety laws." 58 Pa. Stat. § 801.103.

The PUC rejected PIOGA's argument, finding that Act 127 defines "Federal pipeline safety laws" as "[t]he provisions of 49 U.S.C. Ch. 601 (relating to safety), the Hazardous Liquid Pipeline Safety Act of 1979 (Public Law 96-129, 93 Stat. 989), the Pipeline Safety Improvement Act of 2002 (Public Law 107-355, 116 Stat. 2985) and the regulations promulgated under the acts." 58 Pa. Stat. § 801.102. The PUC reasoned that because 49 C.F.R. Subtitle B, Subchapter D, Parts 190—199, were promulgated pursuant to 49 U.S.C. Ch. 601, those Parts were subject to Act 127 and thus fall under the PUC's jurisdiction. Accordingly, the PUC denied PIOGA's Petition and determined that Type R pipeline operators must register annually with the PUC and it must maintain a registry of these operators.

In addition to the registration requirements, the PUC clarified two points on assessment and reporting obligations for Type R pipelines. The PUC said that Act 127 assessments apply to "regulated onshore [gas] gathering pipeline miles." 58 Pa. Stat. § 801.503(b). Because Type R pipelines are specifically excluded from that definition under 49 C.F.R. Part 192, the PUC determined that there is no basis under Act 127 to assess Type R pipeline operators. Regarding reporting, the PUC explained that although it has a duty and the authority under Act 127 to regulate pipeline operators consistent with federal pipeline safety laws, PHMSA intends to enforce the 40 C.F.R. Part 191 reporting requirements for Type R intrastate pipeline operators, meaning the PUC does not need to enforce those requirements at this time.

The Implementation Order, PIOGA's Petition, and the Order, as well as other related documents, are available at PUC Docket # M-2012-2282031 at https://www.puc.pa.gov/search/document-search/.

PADEP Preempted by PHMSA Regarding November 2022 Incident at Natural Gas Storage Facility

The Pennsylvania Department of Environmental Protection (PADEP) and Equitrans, L.P. (Equitrans), have reached a settlement regarding the administrative order issued by PADEP on December 8, 2022 (Order). *See* Stipulation of Settlement, *Equitrans, L.P. v. PADEP*, EHB Docket No. 2023-003-B (Apr. 12, 2023). As previously reported in Vol. 40, No. 1 (2023) of this *Newsletter*, PADEP issued the order in response to the November 2022 incident at Equitrans' Rager Mountain Gas Storage Reservoir (Rager Mountain Facility) in Cambria County, Pennsylvania. The order required Equitrans to, inter alia, conduct mechanical integrity testing of its Rager Mountain storage wells, recondition and plug the wells as needed, and retain a third party to audit "all aspects of Equitrans' storage field operations." Equitrans appealed the Order in early January, arguing that PADEP's jurisdiction over the Rager Mountain Facility was preempted by the federal Natural Gas Act and Pipeline Safety Act, which grant certain exclusive jurisdiction to the Pipeline and Hazardous Materials Safety Administration (PHMSA) and Federal Energy Regulatory Commission (FERC) with regard to interstate natural gas storage facilities.

The April 12 stipulation of settlement between PADEP and Equitrans provides that the Rager Mountain Facility is "subject to the jurisdiction of FERC under the Natural Gas Act pursuant to a certificate of public convenience and necessity, and to the jurisdiction of PHMSA under the Pipeline Safety Act." The stipulation of settlement further provides that PADEP would rescind its order and that Equitrans would withdraw its appeal and negotiate a final safety order with PHMSA regarding the Rager Mountain Facility.

TEXAS – OIL & GAS

William B. Burford, Reporter

Texas Supreme Court Announces Presumption That "Double Fraction" of 1/8 Mineral Interest Means the Stated Fraction of All

The court in *Van Dyke v. Navigator Group*, No. 21-0146, 66 Tex. Sup. Ct. J. 333, 2023 WL 2053175 (Tex. Feb. 17, 2023, pet. for reh'g filed), *rev'g* 647 S.W.3d 901 (Tex. App.—Eastland 2020), construed a 1924 deed from George H. and Frances E. Mulkey to G.R. White and G.W. Tom, conveying their ranch subject to the following mineral reservation: "It is understood and agreed 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 trial court granted summary judgment to the successors to the grantees' interest (referred to in the opinion as the "White parties"), declaring the deed to have unambiguously reserved only 1/16 of the mineral estate and to have conveyed 15/16. The court of appeals affirmed. *See* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. The supreme court reversed, agreeing with the successors to the grantors' interest, the "Mulkey parties," that the deed instead reserved one-half of the minerals.

The court based its conclusion on the "now-familiar observation" that at the time of the deed "1/8" was widely used as a term of art to refer to the total mineral estate, because 1/8 was long the standard royalty rate under oil and gas leases. *Van Dyke*, 2023 WL 2053175, at *5. (Interestingly, the court cites little or no authority for this observation of the use of the 1/8 fraction as a "term of art" other than that, as is undeniably true, 1/8 was at the time the usual royalty rate.) In doing so it extended its holding in *Hysaw v. Dawkins*, 483 S.W.3d 1 (Tex. 2016), to announce "a rebuttable presumption that the term 1/8 in a double fraction in mineral instruments of this era refers to the entire mineral estate." *Van Dyke*, 2023 WL 2053175, at *7. Thus, although the decision in *Hysaw* had seemed to turn on the need to harmonize a testator's devise of a royalty interest of "one-third of one-eighth" to each of her three children with a later indication in the will that each child would receive "one-third of . . . the unsold royalty" remaining at her death, the use of the "double fraction" of 1/2 of 1/8 in the Mulkey deed was, in and of itself, sufficient to demonstrate the parties' intention that the grantors retain one-half, not 1/16, of the minerals. The logic of the *Hysaw* analysis, the court declared, required that it *begin* with a presumption that the "mere" use of such a double fraction was purposeful and that 1/8 reflected the *entire* mineral estate, not just 1/8 of it. *Id.*

The court made clear that the new presumption is rebuttable. "A rebuttal could be established by express language, distinct provisions that could not be harmonized if 1/8 is given the term-of-art usage . . . , or even the repeated use of fractions *other* than 1/8 in ways that reflect that an arithmetical expression should be given to all fractions within the instrument." *Id.* Such a rebuttal, the court observed, might be sufficiently clear that the double fraction should be applied arithmetically as a matter of law, *id.*, or the instrument might have enough textual evidence to "drain confidence in the presumption" only enough to render it ambiguous so as to require recourse to extrinsic evidence of its intention, *id.* at *8.

The court acknowledged that prior cases in which fractions of 1/8 have been found actually to mean those fractions of all have "often" required harmonization of conflicting provisions within the text. *Id.* The court had never suggested a default rule, though, that requires multiplication unless doing so would contravene some other provision of the text, it said. *Id.* Whether all the cases in which double fractions with 1/8 as a component have been construed according to the disfavored "arithmetical" approach, where nothing in the instrument either confirmed or contradicted that construction, are to be considered overruled by this decision is left unexplained.

Even if the court were less persuaded by its double-fraction analysis, the court continued, it would still recognize the Mulkeys' ownership of one-half of minerals on the basis of the presumed-grant doctrine. *Id.* at *9. The Mulkey parties had introduced summary judgment evidence that, in their view and the court's, indicated that both the grantors and grantees, or successors to their interests, had at times after the deed recognized that the minerals were owned equally by the grantors and grantees. *Id.* The Mulkey parties' evidence, according to the court, conclusively established the presumed-grant doctrine's three elements: (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.* at *9–10. The court of appeals' imposition of an additional requirement, that there be a "gap" in the title and not merely disagreement about the correct interpretation of both sides' source deed, had been incorrect, according to the court. *Id.* at *9. Moreover, it believed, the Mulkey parties' evidence was enough to prove such a gap even if it were needed. *Id.*

Editor's Note: The reporter's law firm has represented members of the White parties group in this case. The decision is not final as of this writing, as the time for possible rehearing has not elapsed.

Texas Supreme Court Enforces Lease Provision for Addition to Royalty for Post-Sale Costs Deducted from Sale Price

The court in *Devon Energy Production Co. v. Sheppard*, No. 20-0904, 66 Tex. Sup. Ct. J. 421, 2023 WL 2438927 (Tex. Mar. 10, 2023, pet. for reh'g filed), *aff'g* 643 S.W.3d 186 (Tex. App.—Corpus Christi 2020), construed oil and gas leases by the Sheppard and Crain families covering their mineral interests in DeWitt County, Texas. The leases all called for the payment to the lessors, as royalty, of a specified fraction of gross proceeds from the sale of oil and gas (if greater than the posted price of oil and the wellhead market value of gas), expressly without deduction of the costs of production and of specified post-production expenses. The leases also included the following as paragraph 3(c):

> If any disposition, contract or sale of oil or gas shall include any reduction or charge for the expenses or costs of production, treatment, transportation, manufacturing, process or marketing of the oil or gas, then such deduction, expense or cost shall be added to . . . gross proceeds so that Lessor's royalty shall never be chargeable directly or indirectly with any costs or expenses other than its pro rata share of severance or production taxes.

Id. at *2 (alteration omitted) (emphasis omitted).

The lessees calculated and paid royalty to the lessors based on the amount they received from oil and gas purchasers, without deduction of costs incurred by the lessees for transportation and marketing up until the point of sale. Where the lessee's price according to its sale contracts included deductions from a stated gross price, whether or not expressly for the purchaser's downstream costs, or for the exclusion of gas used as fuel or lost before resale, the lessees' royalty calculations incorporated those price deductions. The royalty owners sued their lessees, and the trial court granted them summary judgment declaring that any deductions from the gross price stated in the lessees' sale contracts must be added to the proceeds actually received in the calculation of the lessors' royalty, and the court of appeals affirmed the trial court with respect to sale contracts in which the price was explicitly reduced by the purchaser's downstream expenses. *See* Vol. XXXVII, No. 3 (2020) of this *Newsletter*.

The supreme court affirmed the judgment of the court of appeals, holding that under paragraph 3(c), the lessees were required, in calculating the lessors' royalty, to add to the gross proceeds they received from the sale of oil and gas any price deductions that the lessees' sale contracts explicitly tied to costs of "production, treatment, transportation, manufacturing, process[ing], or marketing" by the third-party purchaser. The court rejected the lessees' argument that royalty was intended to be payable on their "gross proceeds" actually received from sale and that the purpose of paragraph 3(c) was only to prohibit deductions for the lessees' own expenses. "Paragraph 3(c) [was] not textually constrained to the expenses incurred by the seller or prior to the point of sale," the court observed, and its inescapably broad language was clear in requiring "any reduction or charge" for postproduction costs that have been included in the producer's disposition of production to be "added to" gross proceeds. *Id.* at *9. Paragraph 3(c) would serve no purpose at all, the court said, if not to allow the amount on which the royalty payment is calculated to exceed gross proceeds. *Id.* An obvious and reasonable purpose for a provision like this one, the court concluded, is to provide the producer with the flexibility to sell production at any point downstream of the well while discharging the landowners from the usual burden of the cost of rendering production marketable. *Id.*

The court of appeals had held that where the lessees' sale contracts called for reductions from the purchase price by stated amounts without specifying that the reductions were related to downstream costs, the amounts of those reductions need not be added to gross proceeds in the calculation of royalty, and that aspect of the lower court's judgment was not appealed to the supreme court. Presumably the producers will henceforth make certain, if possible, that their production sale contract prices will not be directly tied to the purchaser's downstream costs.

Force Majeure Clause Held Inapplicable Where Force Majeure Event Did Not Cause Lessee's Failure to Meet Drilling Deadline

The court in *Point Energy Partners Permian LLC v. MRC Permian Co.*, No. 21-0461, 2023 WL 3028100 (Tex. Apr. 21, 2023), *rev'g in part* 624 S.W.3d 643 (Tex. App.—El Paso 2021), considered four oil and gas leases held by MRC Permian Company (MRC) covering almost 4,000 acres in Loving County, Texas. The trial court had rendered summary judgment in favor of the lessors and their new lessee, Point Energy Partners Permian LLC (Point Energy), that the leases had partially terminated because of MRC's failure to commence a well within the time required by the lease. The court of appeals reversed, agreeing with MRC that the trial court had erroneously failed to consider the effect of the leases' force majeure clause, which read as follows:

> 13. Force Majeure. When Lessee's operations are delayed by an event of force majeure, being a noneconomic event beyond Lessee's control, if Lessee shall furnish Lessor a reasonable written description of the problem encountered within 60 days after its commencement, and Lessee shall thereafter use its

> best efforts to overcome the problem, this lease shall remain in force during the continuance of such delay, and Lessee shall have 90 days after the reasonable removal of such force majeure within which to resume operations . . . .

Id. at *3.

Each lease provided for a primary term that ended on February 28, 2017. At that time they would terminate as to all land except tracts then containing a commercial well, except that the partial termination could be delayed by the lessee's conducting a continuous drilling program. The lease would be preserved as to all of the land so long as MRC began drilling a new well within 180 days after the commencement of the drilling of the last previous well. Because MRC had commenced its last well during the primary term on November 22, 2016, the lease required it to begin drilling the next one by May 21, 2017, in order to avoid the partial termination. *Id.* at *2.

MRC was using a specific drilling rig, "Rig 295," in its operations in the area because of its experienced crewmen and specialized equipment. It had scheduled Rig 295 to spud a well on the land within these leases on May 11, 2017, but because of an administrative error, MRC rescheduled the spudding until June 2017, beyond the continuous-drilling deadline. On April 21, 2017, though, Rig 295 had experienced a delay of roughly 30 hours during the drilling of a well on other land when unexpected wellbore instability occurred and needed to be addressed. On June 13, 2017, 53 days afterward, MRC notified the lessors of the four leases by letter of the April event involving Rig 295. On June 15, 2017, Point Energy, having acquired new leases from the mineral owners, responded to MRC's letter, questioning that MRC had complied with the leases' continuous development provisions, whereupon MRC filed suit for a declaratory judgment that the force majeure clause had extended its drilling deadline until 90 days after the Rig 295 delay. *Id.* at *3.

The court of appeals held that under a literal reading of the force majeure clause, it applied to extend the lease's term for 90 days after the 30-hour delay on April 21. The operations were those of the lessee, and nothing in the force majeure clause imposed a condition that the delaying event occur on-lease. Nor did it stipulate that the claimed force majeure must be a substantial factor in MRC's failure to meet its deadline, according to the court of appeals. *See* Vol. XXXVIII, No. 2 (2021) of this *Newsletter*.

The supreme court disagreed with MRC and the court of appeals that the force majeure event, in order to extend the term of the lease, need not have caused the lessee to miss its deadline. The lessee's operations must be "delayed by" the force majeure event, the court pointed out, invoking a causal-nexus requirement that was a necessary predicate to invoke the clause. *Point Energy*, 2023 WL 3028100, at *8. A vital part of the text of the force majeure clause was its purpose, it continued, which was to address inability to meet deadlines imposed by the lease. MRC's untethering of operations from their corresponding lease deadlines in claiming a delay, the court believed, was at odds with a fair reading of the force majeure clause and embraced a wooden, isolated literalism over the natural, contextual construction. *Id.* at *10. Because MRC's erroneous scheduling, and not the 30-hour delay in drilling on a different lease, had caused MRC to miss its deadline, the court concluded, the force majeure clause did not preserve the lease. *Id.* at *12.

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

Texas Supreme Court Construes Rights to Be Offered Reassignment Under Purchase and Sale Agreements

Apache Corp. v. Apollo Exploration, LLC, No. 21-0587, 2023 WL 3134243 (Tex. Apr. 28, 2023, pet for reh'g filed), *rev'g in part* 631 S.W.3d 502 (Tex. App.—Eastland 2021), involved separate but substantially identical purchase and sale agreements (PSAs) under which, in 2011, Apollo Exploration, LLC, Cogent Exploration, Ltd., Co., SellmoCo, LLC, and Gunn Oil Company (Gunn), owners of 98% of the working interest under 109 oil and gas leases covering over 120,000 acres in the Texas Panhandle, including one on the Bivins Ranch for approximately 100,000 acres, sold 75% of their combined interests to Apache Corp. (Apache). Gunn sold its remaining interest to Apache in 2014. The other three sellers sued Apache, alleging breaches of Sections 2.5 and 4.1 of each PSA.

Section 2.5 afforded each of the sellers the option to "back in" for up to 1/3 of the interests conveyed at a "back-in trigger" of 200% of "project payout." "Project payout" was defined as the first day of the next calendar month following the point in time when Apache's revenue from production, less royalty and other burdens and severance taxes, reached the sum of the price paid to the seller, a "drilling credit" (apparently defined elsewhere in the PSA), Apache's actual costs to explore, drill, and complete wells to the extent attributable to the leases assigned, and operating costs chargeable under a form of operating agreement attached to the agreement, as well as marketing and disposal costs. Additionally, the seller had the right at any time to pay Apache the remaining balance for the back-in trigger to receive the back-in interest as though the back-in trigger had occurred. Apache was required to provide the sellers annual written statements of the status of project payout and the back-in trigger. The plaintiff sellers maintained that they were entitled to their back-in interest when project payout occurred, while Apache's position was that the phrase "200% of project payout" contemplated a 2 to 1 return of its expenses notwithstanding that the back-in trigger was defined as a particular day rather than as a multiple of Apache's expenses.

In Section 4.1 of their PSAs, the parties had agreed that on or before November 1 of each year, Apache would provide the sellers a written budgeted drilling commitment for the upcoming calendar year. If that commitment would result in the loss or release of any of the leases in the next year, it further required Apache to concurrently offer "all of [its] interest in the affected Leases (or parts thereof) to Seller at no cost to Seller," *id.* at *14 (emphasis omitted), and, upon the seller's acceptance, to assign those leases (or parts thereof) to the seller, in order to "provide Seller the option and ability to perpetuate all the Leases so offered . . . through a drilling program with one drilling rig," *id.* at *15. After submitting the annual commitment to the sellers, according to the PSAs, Apache was required to make a good-faith effort to follow it but was not liable if it was unable to do so despite that effort. The sellers alleged that Apache had damaged them by failing to provide the required commitment in 2014 and then allowing substantial lease acreage to expire, without having offered it to the sellers as required.

The Bivins Ranch lease was dated effective January 1, 2007, "from which date" the anniversary dates of the lease would be computed, and provided for a primary term of three years "from the effective date." The lease could thereafter be maintained in effect as to all of its acreage by the lessee's drilling specified wellbore footages "each year after" the expiration of the primary term. If those requirements were not met, the lease would partially expire. Apache had conducted the required operations through 2014, so that the lease remained intact at the end of that year and into 2015. After oil prices declined between 2014 and 2015, though, Apache declined to drill in 2015 so that the lease expired as to a significant amount of its acreage. The value of the lost leasehold, which the sellers asserted should have been offered to them, was the basis for their claimed damages for Apache's breach of Section 4.1.

The question the court first addressed was when Apache's breach of Section 4.1 occurred, if at all. That issue was of critical importance to the measure of the sellers' alleged damages, because the value of the acreage had declined (by $180 million, according to Apache) between the end of 2014 and the end of 2015. The sellers maintained that Apache should have offered the Bivins Ranch lease to them on November 1, 2014, because the lease would expire on December 31, 2015, if the 2015 drilling commitment were not met. Apache countered that the lease's expiration date was not until January 1, 2016, so that it had no obligation to offer back any leases until November 1, 2015.

Reversing the court of appeals' holding that the lease's expiration date was a question of fact, *see* Vol. XXXVIII, No. 3 (2021) of this *Newsletter*, the supreme court agreed with Apache that it did not terminate until January 1, 2016, so that Apache's breach, if any, did not occur in 2014. The court's determination, in its view, was simply an application of the common-law rule that the calculation of a period of time "from" a particular date includes the ending anniversary date unless a different intent is expressed in the relevant instrument. *Apache*, 2023 WL 3134243, at *7. The Bivins Ranch lease provided that its anniversary dates and the end of its primary term would be computed "from" its effective date of January 1, 2007, and that its continuous drilling requirements must be met "each year after" the primary term. A recorded memorandum giving notice of the lease stated that its primary term ended on December 31, 2009, but the memorandum was expressly subject to the lease that unambiguously, according to the court, provided for an ending date of January 1. *Id.* at *9.

The court turned to the sellers' argument that Apache had also breached Section 4.1 by failing to offer back to each of them not only the interests that the plaintiff sellers had assigned to Apache but also the additional interest that Apache had acquired from Gunn. The PSAs, the sellers pointed out, required Apache to offer "all of Purchaser's interest in the affected Leases," and that "all" means "all," including the Gunn interest. *Id.* at *14. This argument, the court declared, could not overcome a glaring problem, that according to this interpretation Apache would have been required under each PSA to offer back to *each individual* seller the interests it purchased from all others and would owe the *same* interests to each separate seller. *Id.* If Section 4.1 had expected Apache to make the offer the sellers claimed, said the court, it would have explained how the process of distributing the interests would work. *Id.* at *15. The word "all," in the court's interpretation, meant that each seller would receive *all* of the interest that *it* sold to Apache. *Id.*

The court then considered Section 2.5 of the PSAs and agreed with Apache that the sellers would not become entitled to their back-in interests until Apache recovered revenues of double its expenses. Apache's reading resulted in a "rather awkward linguistic construction" of the definition of the back-in trigger, which appeared to refer to "200% of" a certain day, the court acknowledged, but only Apache's reading explained the presence of the 200% language. *Id.* at *16.

The court's holding concerning the timing of Apache's obligation seems sensible, and its confirmation of a time-tested common-law rule is welcome. The decision might be seen, though, as departing from the court's repeated reluctance in recent years to rely on "mechanical" rules where the contents of an agreement, taken as a whole, indicate a different intention. The court here devotes hardly any discussion to Section 4.1's explanation of its purpose: to provide each seller the ability to perpetuate the expiring leases by drilling. If the sellers and Apache intended to afford the sellers the opportunity to preserve the expiring leasehold if Apache's own anticipated operations would not, it seems implausible that their agreement was that the sellers be offered the leases no earlier than November 1 of the same year in which an unmet drilling requirement must be performed.

Purchasers of Oil and Gas Lease Held Not to Have Released Claim Against Prior Lessee

The court in *Finley Resources, Inc. v. Headington Royalty, Inc.*, No. 21-0509, 2023 WL 3399104 (Tex. May 12, 2023), *aff'g* 623 S.W.3d 480 (Tex. App.—Dallas 2021), construed an agreement between Headington Royalty, Inc. (Headington), and Petro Canyon Energy, LLC (Petro Canyon), for Headington's acquisition of an oil and gas lease Petro Canyon held covering a tract in Loving County, Texas.

The land had previously been subject to a 1966 lease under which Finley Resources, Inc. (Finley), owned the leasehold in shallow depths and Headington owned the leasehold in deeper depths. The lease was held by production from oil wells operated by Finley that produced from the shallow depths. Those wells ceased to produce in paying quantities, causing the lease to expire no later than March 31, 2017, as to both the shallow and deep rights. Headington claimed that its loss of the deep leasehold resulted from Finley's failure to provide Headington contractually-required notices and data that would have alerted it to the impending expiration.

Before the lease's expiration had become clear, in June 2017, Petro Canyon acquired a top lease from the mineral owner and reached an agreement with Finley for a release of its rights under the 1966 lease. The agreement included Petro Canyon's indemnification of Finley against any liabilities arising out of Finley's ownership or operation of that lease. On October 3, 2017, Petro Canyon and Headington entered into an acreage-swap agreement by which Headington would acquire the new 2017 lease. That agreement provided that Headington "waives, releases, acquits and discharges Petro Canyon and its affiliates and their respective officers, directors, shareholders, employees, agents, predecessors and representatives for any liabilities, claims, demands, causes of action or obligations . . . related in any way to [the land covered by the lease]." *Id.* at *2 (emphasis omitted). The acreage-swap agreement did not mention Finley or Headington's claims against it.

Headington then sued Finley for breach of contract and negligent misrepresentation, alleging that Finley's noncompliance with its notice and disclosure obligations had resulted in loss of the 1966 lease and Headington's consequent costs to acquire the new lease and its increased royalty obligation. Petro Canyon, as Finley's potential indemnitor, intervened and sought a declaration that Headington's release in the acreage-swap agreement barred Headington's claims against Finley because Finley was a "predecessor" to Petro Canyon and thus within the class released from any liability related to the Loving County tract. The trial court granted summary judgment to Finley and Petro Canyon, but the court of appeals reversed, holding that the word "predecessors" included entities within Petro Canyon's corporate structure but not its predecessors in title to the land. The supreme court affirmed the court of appeals.

The acreage-swap agreement, construed as a whole, according to the court, unambiguously narrowed the scope of what had the potential to be a very broad term. *Id.* at *9. Finley was not named in the agreement, the court observed, and "predecessors" grammatically referred back to the entities released—Petro Canyon and its affiliates—connoting a prior connection to the corporate entities themselves, not the land. *Id.* One simply could not reasonably discern from anything in the agreement that Headington intended to release its claims against Finley, it concluded. *Id.* at *8. Headington was therefore entitled to summary judgment on the defenses of release, waiver, and third-party beneficiary. *Id.* at *10.

Reservation of 1/4 of the "Land Owner's 1/8th Royalty" Held a "Floating" 1/4 of Lease Royalty

In the first case other than *Van Dyke* itself to apply the rebuttable presumption, recently created in *Van Dyke v. Navigator Group*, No. 21-0146, 66 Tex. Sup. Ct. J. 333, 2023 WL 2053175 (Tex. Feb. 17, 2023, pet. for reh'g filed), that a "double fraction" of 1/8 instead means a fraction of all, the court in *Royalty Asset Holdings II, LP v. Bayswater Fund III-A, LLC*, No. 08-22-00108-CV, 2023 WL 2533169 (Tex. App.—El Paso Mar. 15, 2023, pet. filed) (mem. op.), held that the reservation in a 1945 deed of an "undivided 1/4th of the land owner's usual 1/8th royalty interest (being a full 1/32nd royalty interest)" was a floating 1/4 of the royalty, not limited to 1/4 of 1/8 of production, entitling the owners to 1/4 of 1/4 (1/16) of production under the current 1/4 royalty lease.

Following the *Van Dyke* rebuttable presumption, the court read the deed's use of a multiple fraction of 1/8 as reserving, subject to possible rebuttal, "an undivided 1/4 of the entire mineral interest" (presumably intending to mean 1/4 of any royalty, not really the entire "mineral interest"). With an explanation no more cogent than it gave in construing a similar royalty reservation in *Bridges v. Uhl*, 663 S.W.3d 252 (Tex. App.—El Paso 2022, no pet. h.), *see* Vol. 40, No. 1 (2023) of this *Newsletter*, the court found support for the notion that "1/8" was a proxy for "the landowner's royalty" in the use of the word "usual" and in the reference to the "land owner's" usual 1/8. *Royal Asset*, 2023 WL 2533169, at *4. Although the court acknowledged that the parenthetical "1/32nd royalty interest" would "imply" a fixed royalty interest if considered in isolation, it declared that it "merely restates" the prior clause if the multiple fractions were intended to show a fixed royalty. *Id.* at *5. Because the clause was within parentheses, however, the court could consider it non-essential and, somehow, consistent with "the rebuttable presumption that the royalty interest is a floating 1/4 nonparticipating royalty interest" (presumably meaning to say 1/4 of the royalty rather than 1/4 of production as a 1/4 "royalty interest" would ordinarily connote). *Id.*

It is difficult to avoid the conclusion that recent fixed-versus-floating royalty cases, very much including this one, have created a troubling exception to the once-reliable rule that deeds and other legal instruments must be construed according to their plain meaning. The fact that courts, in opinions such as this one, make little or no effort to distinguish or overrule, or even examine, decades of plainly contrary precedent seems to raise unavoidable questions concerning the stability of mineral titles.

Term of Mineral Reservation Perpetuated by Production from Pooled Unit

The question before the court in *Lil C Ranch, LLC v. Ridgefield Eagle Ford Minerals, LLC*, No. 14-21-00285-CV, 2023 WL 2386940 (Tex. App.—Houston [14th Dist.] Mar. 7, 2023, no pet.) (mem. op.), was whether the term of a mineral reservation to the grantors in a 1996 deed had been extended by oil and gas production or had expired.

The deed, conveying a 46.209-acre tract of land in Washington County, Texas, reserved the entire mineral estate and 75% of the royalties for a period of 10 years and so long thereafter as production of any minerals continued in paying quantities. Lil C Ranch, LLC (Lil C), acquired the grantee's interest in 36.2 acres out of the land in 2014 and filed suit seeking a declaratory judgment and title to the mineral estate in the land it had acquired on the basis that there had been no mineral production from the land described in the deed in 2006, 10 years after its date. Ridgefield Eagle Ford Minerals, LLC (Ridgefield), which had acquired the grantors' mineral interest, intervened and asserted that the mineral reservation had not expired because the grantor had executed an oil and gas lease with a pooling provision, the land had been pooled, and there was production from the pooled unit that extended the term. The trial court granted summary judgment to Ridgefield, and Lil C appealed.

After first reversing the summary judgment for Ridgefield on the ground that it was framed as a declaratory judgment whereas a trespass-to-try-title action was the sole available cause of action, *id.* at *7, the court turned to Lil C's argument that it was entitled to a judgment on its claim for title to the minerals. It was not, the court held. "The legal consequence of pooling," the court pointed out, "is that production anywhere on the pooled unit and operations incidental to that production are regarded as taking place on each pooled tract." *Id.* at *8. Applying that legal consequence, the court concluded that once pooling occurred, the pooled tracts, including Lil C's 36.2 acres, no longer maintained separate identities; thus, production from the pooled unit was considered production from Lil C's land. *Id.* at *9.

The court is of course correct in its observation of the effect of pooling. It is fair to wonder, though, whether it is as obvious as the court seems to assume that the parties to the 1996 deed intended that pooling to which only the grantor agreed would be binding on the grantee. If pooling is not binding on a nonparticipating royalty owner in the absence of any express provision in the instrument creating it, why is it binding on the owner of a future interest that depends on an instrument that does not mention pooling?

Operator Held Not Liable for Injury to Workover Contractor's Employee

The court in *Kilbourne v. Ovintiv Exploration, Inc.*, No. 09-21-00375-CV, 2023 WL 1828152 (Tex. App.—Beaumont Feb. 9, 2023, no pet. h.) (mem. op.), affirmed summary judgment for Ovintiv Exploration, Inc. (Ovintiv), the operator of a well in North Dakota, against Chris Kilbourne, an employee of Foremost Well Service (Foremost), who was injured when Foremost's workover rig floor fell on him.

Ovintiv had engaged Foremost to provide workover services on its well under a master work or service contact that required Foremost to provide a workover rig and experienced crew. Ovintiv also engaged an independent contractor to provide "company men" for general oversight of the operation. Summary judgment testimony indicated that Foremost personnel failed to employ routine safety precautions but that no one acting on behalf of Ovintiv specifically instructed Foremost on procedures that would have prevented the accident or observed whether those were being followed. Kilbourne offered expert opinion testimony that the accident would likely have been prevented if Ovintiv or its representatives had undertaken proactive efforts to ensure site safety.

There was some question whether North Dakota or Texas law should govern, but the court determined there could be no harm in applying Texas law inasmuch as the parties agreed on appeal that both Texas and North Dakota have adopted *Restatement (Second) of Torts* § 414 to determine whether a property owner is liable for the work of its independent contractor. *Id.* at *9. Since Kilbourne was an employee of Ovintiv's independent contractor, the court noted, he was required, in order to show that Ovintiv had breached a duty to him, to prove that Ovintiv exercised control over the operative details of the work Kilbourne performed when the accident occurred. *Id.* at *10. *Restatement (Second) of Torts* § 414 imposes on the owner a duty to exercise reasonable care, the court went on, when the owner retains some control over the manner in which contractor's work is performed—more than a general right to order the work to start and stop, inspect progress, or received reports. *Id.* Ovintiv's agreement with Foremost did not provide Ovintiv any contractual rights to exercise authority over the methods and means by which Foremost performed its work, and the summary judgment evidence showed that Ovintiv and its contract company man had not actually exercised any control over the work of the Foremost crew. *Id.* In particular, they had not instructed the Foremost crew on how to secure the rig floor that had fallen on Kilbourne. *Id.* There was no evidence, the court concluded, that Ovintiv had exercised some control over the manner in which Foremost performed its work; thus, it had no duty to Kilbourne. *Id.*

Summary Judgment for Operator Against Contractor's Injured Rig Hand Reversed

Gerardo Luna was employed as a derrick hand by Big Dog Drilling, a drilling contractor hired by Endeavor Energy Resources, L.P. (Endeavor), to drill the Guitar 1-4 #1H Well near Big Spring, Texas. A rope he was pulling while it was tied to the rig's elevation ears broke, causing him to fall and injure himself. He sued Endeavor, alleging its negligence had caused the injury, and when the trial court granted summary judgment to Endeavor, he appealed. The court in *Luna v. Endeavor Energy Resources, L.P.*, No. 11-21-00064-CV, 2023 WL 2603013 (Tex. App.—Eastland Mar. 23, 2023, (no pet. h.) (mem. op.), reversed the summary judgment.

Endeavor relied on Chapter 95 of the Texas Civil Practices and Remedies Code, which limits a property owner's liability for common-law negligence claims that arise out of a contractor's or subcontractor's work on an improvement to property. After observing that there is a split of authority among Texas courts whether a drilling rig is an improvement, the court concluded that the determination of that issue would not affect the outcome of this case. *Id.* at *3. Under Chapter 95, it pointed out, a property owner is liable for its acts of negligence if it (1) exercised or retained some control over the manner in which the work was performed and (2) had actual knowledge of the danger or condition resulting in the injury and failed to adequately warn of it. *Id.* at *5. Here, Luna's summary judgment evidence indicated that Endeavor's field superintendent had been giving the drilling crew directions, including some involving the rope that had broken, and that he had instructed Luna to continue working even after the danger that the rope could break had become apparent. *Id.* at *6. Against Endeavor's argument that it should not be liable for failure to warn because Luna was aware of the danger, the court held that where an owner seeks to control the work of a contractor by expressly requiring the contractor make use of the premises in a manner it knows to be dangerous, the owner remains liable despite the injured person's awareness of the danger. *Id.* at *6–7. Because Luna had raised more than a scintilla of evidence of Chapter 95's inapplicability, the court concluded, summary judgment had been improperly granted. *Id.* at *7.

Lessee's Release of Lease Relieved Its Obligation to Drill or Pay

The court in *Parsley Minerals, LLC v. Flat Creek Resources, LLC*, No. 03-21-00337-CV, 2023 WL 2052315 (Tex. App.—Austin Feb. 17, 2023, no pet.) (mem. op.), considered provisions of an oil and gas lease between Parsley Minerals, LLC (Parsley), as lessor, and Flat Creek Resources, LLC (Flat Creek), as lessee, covering roughly 640 acres in Reeves County, Texas.

The lease was dated October 1, 2018, and provided for a primary term of three years. According to the lease's Paragraph 5, "[n]otwithstanding anything to the contrary," the lessee must commence the drilling of a horizontal well on or before April 1, 2020 (which date was amended by a later mutual agreement to October 1, 2020), or, if it failed to do so, pay the lessor $500,000. *Id.* at *1 (alteration in original). Paragraph 5 concluded by calling the right to the payment a condition to the granting of the lease, resulting in forfeiture of the lease if not complied with. The lease also included a Paragraph 7, which provided in pertinent part, "[l]essee shall have the right at any time and from time to time during the term of this Lease to release from the lands covered hereby any lands subject to this Lease and thereby be relieved of all obligations thereafter accruing as to the acreage so released . . . ." *Id.* at *4 (emphasis omitted).

On September 23, 2020, about a week before the October 1 deadline, Flat Creek released the lease. Parsley sued Flat Creek for breach of contract, seeking $500,000 in damages. The trial court dismissed the suit on the grounds that it had no basis in law or fact, and the court of appeals affirmed.

The lease's plain language, the court pointed out, established that Parsley would not have any legally enforceable claim against Flat Creek until October 1, 2020, the date on which Flat Creek had either to drill or pay. *Id.* Thus, the court reasoned, because Flat Creek released the lease before then, it relieved itself of "all obligations thereafter accruing," including the obligation to drill or pay. *Id.* The court cited *Superior Oil Co. v. Dabney*, 211 S.W.2d 563 (Tex. 1948), a case in which a similar surrender clause was held to have avoided the lease's obligation to drill or pay, emphasizing the court's observation that the "provision did not state in effect 'all obligations except the duty to drill a test well,' but in comprehensive language declared that a surrender would relieve the lessee of all obligations." *Parsley*, 2023 WL 2052315, at *5 (quoting *Superior Oil*, 211 S.W.2d at 564–65).

The court rejected Parsley's argument that the lease's reference to the drill-or-pay obligation as a condition to the granting of the lease made its accrual date October 1, 2018, the date of the lease. The parties' formation of their contract was not contingent on Flat Creek's performance, the court observed, and again, Parsley could not have had an enforceable claim against Flat Creek until October 1, 2020. Nor did the use of the phrase "notwithstanding anything herein to the contrary" preclude Flat Creek's release from relieving it of its drill-or-pay obligation, as Parsley urged. *Id.* at *6. Flat Creek's right to release the lease did not conflict with its obligation to drill by the deadline or pay. *Id.* That conclusion did not render the "notwithstanding" clause meaningless, the court explained. *Id.* The "notwithstanding" clause was broad and not expressly directed to another lease provision (i.e., the surrender clause). *Id.* The purpose of the clause was to ensure that the drill-or-pay obligation controlled over any other potentially conflicting provision, the court declared, but an actual conflict need not arise to keep the clause from being rendered meaningless. *Id.* at *7.

Railroad Commission Determination on Lack of Standing Upheld

In 2018 Boykin Energy LLC (Boykin) filed applications seeking the Texas Railroad Commission's (Commission) approval of permits to dispose of oil and gas waste by injection into a formation not productive of oil and gas. Texas Water Code § 27.031 grants standing to challenge such an application to an "affected person," defined as one "who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor." Apache Corporation (Apache), the owner of an oil and gas lease within approximately two miles and an active well within approximately three miles of the disposal well's proposed location, protested the Boykin application as such an "affected person." The disposal wells, Apache claimed, would contaminate the Rustler Aquifer on which it relied for groundwater and would endanger or injure its oil and gas interests in the formation into which the waste would be disposed. After a hearing the Commission concluded that Apache was not an affected person and dismissed its protest. In *Railroad Commission of Texas v. Apache Corp.*, No. 07-22-00014-CV, 2023 WL 2138962 (Tex. App.—Amarillo Feb. 21, 2023, pet. filed) (mem. op.), the court of appeals reversed the trial court's order reinstating Apache's protest and upheld the Commission's determination of Apache's lack of standing.

Judicial review of a Commission decision is conducted under the substantial evidence standard, the court began. *Id.* at *2. The court's determination, it continued, is whether the evidence as a whole would allow reasonable minds to conclude that Apache suffered or will suffer actual injury or economic damage. *Id.* At the contested Commission hearing on the question of standing, Apache had presented evidence of faults that would allow injected waste to migrate into the Rustler Aquifer, but Boykin had presented contrary expert evidence. Boykin also had agreed to take steps to mitigate possible injury to Apache, including reducing the extent of the injection interval and the volumes to be injected. Because reasonable minds could have determined that Apache was not an affected person in view of the conflicting evidence, the court concluded, substantial evidence supported the Commission's decision. *Id.* at *3. Nor had the Commission denied Apache due process: Apache had been fully heard at the contested hearing addressing its status as an affected person, and it is not a denial of due process to deny a person without standing the opportunity to be heard. *Id.* at *4.

Texas Court Held to Lack Jurisdiction of Suit Against Colorado Oil and Gas Operator

In *Caerus Oil & Gas, LLC v. Terra Energy Partners, LLC*, No. 01-22-00191-CV, 2023 WL 2169495 (Tex. App.—Houston [1st Dist.] Feb. 23, 2023, no pet. h.) (mem. op.), the court of appeals reversed the trial court's denial of the special appearance by Caerus Oil and Gas, LLC (Caerus), the operator of wells on oil and gas leases owned by Terra Energy Partners, LLC (Terra), in the Piceance Basin of Colorado, challenging the court's personal jurisdiction of Caerus.

Terra sued Caerus in Harris County, Texas, alleging that Caerus had breached a gas marketing agreement and operating agreements with Terra by taking improper deductions from gas sale proceeds due Terra and seeking to impose unauthorized administrative charges for the operation of a road that served the leases. All of the oil and gas properties and the road were located in Colorado. Caerus asserted that it was a Delaware limited liability company with its principal place of business in Colorado and no office, operations, or activities in Texas. On that basis and on the basis that the dispute involved only properties and operations in Colorado, it argued that Terra had not pleaded allegations bringing Caerus within the Texas long-arm statute. The court agreed with Caerus.

The U.S. Constitution, the court pointed out, "permits a state to assert personal jurisdiction over a nonresident defendant only if it has some minimum, purposeful contacts with the state and if the exercise of jurisdiction will not offend traditional notions of fair play and substantial justice." *Id.* at *9. Unless the defendant's contacts with the state are significant enough that it is generally subject to the state's jurisdiction in any matter, two requirements must be met for a court to exercise specific jurisdiction: (1) the nonresident defendant's contacts with Texas must be purposeful, and (2) the cause of action must arise from or relate to those contacts. *Id.* at *10. Those requirements had not been met, in the court's view. *Id.*

Terra had alleged in support of jurisdiction that Caerus had contracted with a Texas resident, Terra, and made payments and sent invoices to Terra in Texas. The relevant assets were operated and maintained in Colorado, however, the court noted, and merely contracting with a Texas resident and sending payments and invoices there was not determinative of the jurisdictional analysis. *Id.* at *13. Terra also pointed to the gas marketing agreement that permitted Caerus to sell Terra's gas produced from the leases, which stated that it was governed by Texas law. The disputed issue, in the court's analysis, was instead governed by the applicable operating agreements that called for Colorado law to apply; besides, the court remarked, a choice-of-law provision standing alone is insufficient to confer personal jurisdiction. *Id.* at *15.

Judgment for Net Amount Due for Unpaid Obligations Related to Multiple Properties Upheld

1776 Energy Partners, LLC v. Marathon Oil EF, LLC, No. 04-20-00304-CV, 2023 WL 2669669 (Tex. App.—San Antonio Mar. 29, 2023, no pet. h.), involved three joint operating agreements (JOAs) to which 1776 Energy Partners, LLC, and 1776 Energy Operations, LLC (collectively, 1776), and Marathon Oil EF, LLC, and Marathon Oil EF II, LLC (collectively, Marathon), each were parties. Marathon was the operator of the "Culberson Hughes" and "Longhorn" JOAs, and 1776 was the operator of the "Bordovsky" JOA.

Experiencing cash-flow difficulties in 2014 and 2015, 1776 stopped paying its share of expenses billed by Marathon under the Culberson Hughes and Longhorn JOAs and failed to pay Marathon its share of revenue from the wells that 1776 operated under the Bordovsky JOA. In response, Marathon began "netting" the amounts of revenue due 1776 for oil and gas produced from the wells Marathon operated against 1776's unpaid obligations. In doing so it applied revenues from the well on the Culberson Hughes property not only to 1776's unpaid operating expenses billed under the Culberson Hughes JOA but also to 1776's unpaid obligations relating to the other two properties, referred to by the court as "cross-netting."

In late 2016, while Marathon still had not recovered a substantial amount 1776 owed it, Marathon proposed the drilling of three new wells in the contract area of the Culberson Hughes JOA, where Marathon owned approximately 20% of the working interest and 1776 owned approximately 64%. Marathon's well proposal included a "cash call" for the estimated drilling and completion costs, of which 1776's share would be $9.4 million. According to the JOA, if 1776 failed to pay its share within 15 days of an election to participate in the wells, it would be deemed "non-consent," resulting in its relinquishment of its interest in the wells until the wells had reached "payout" (not defined in the court's opinion, but presumably a multiple of the cost to drill and complete the wells). 1776 notified Marathon that it elected to participate in the new wells but, after failed efforts to secure funding for the cost, failed to pay the cost estimates, whereupon Marathon notified 1776 that it was deemed non-consent. The wells were then drilled without 1776's participation.

When 1776 alleged that Marathon had prevented 1776 from acquiring the necessary funding to participate in the new wells by taking the position that it could apply 1776's cash-call amount to other 1776 indebtedness, Marathon filed suit seeking a declaration that 1776's failure to pay rendered it non-consent to the three wells and for breach of 1776's contractual obligations to pay expenses under the Culberson Hughes and Longhorn JOAs and to pay revenues under the Bordovsky JOA. 1776 counterclaimed for a declaration that Marathon's refusal to assure 1776's prospective funding sources that it would not cross-net the cash call for the new wells against 1776's old debts was a repudiation and anticipatory breach of the Culberson Hughes JOA, further alleging fraud by nondisclosure on Marathon's part in that the well proposals had been a ploy to take over 1776's interest in those wells. The trial court granted Marathon's motion for summary judgment that 1776 had breached the JOAs by failing to pay the amounts those agreements required it to pay Marathon and rendered judgment for the amounts 1776 had not paid, crediting 1776 for revenue withheld by Marathon. After a trial the court granted Marathon a directed verdict on 1776's fraud by nondisclosure claim but also granted 1776 a directed verdict that the Culberson Hughes JOA did not require 1776 to pay existing obligations under other JOAs to participate in the new wells. Both parties appealed.

The court of appeals first reversed the trial court's declaratory judgment for 1776 that the Culberson Hughes JOA did not require 1776 to pay existing obligations to participate in the proposed wells, agreeing with Marathon that the matter was not a live controversy ripe for adjudication. *Id.* at *8. "Because 1776 never paid the required cash call," the court explained, "the trial court's declaration about whether Marathon could impose additional obligations on 1776's participation in the wells resolved a hypothetical situation that would not have determined the dispute . . . ." *Id.* The trial court therefore lacked subject matter jurisdiction to render that advisory declaration. *Id.*

The court then rejected 1776's contention that the trial court's summary judgment improperly applied revenues Marathon owed 1776 to 1776's obligations under different JOAs. 1776 did not "demonstrate[] that any application of the cross-netted amounts . . . resulted in a judgment that ordered 1776 to pay amounts it did not actually owe," the court pointed out. *Id.* at *10. Marathon was not required to establish its right of set-off: That right, which 1776 alleged Marathon failed to prove, is an affirmative defense against a breach of contract claim such as Marathon's, said the court, not a required element of such a claim. *Id.* at *11.

The court went on to affirm the trial court's rejection of 1776's fraud by nondisclosure claim. That claim, the court observed, was based on the allegation that Marathon did not intend to drill the three newly-proposed wells if 1776 paid the cash call. *Id.* at *15. The court could see no evidence that 1776 had been damaged by any undisclosed facts. *Id.* at *16. A fraud claimant must show that its damages were caused by the defendant's alleged culpable acts, the court noted. *Id.* Under the circumstances here, 1776 did not participate in the new wells because it never paid the cash call, and it identified no evidence showing that Marathon's purported nondisclosure caused the nonpayment. *Id.*

The court did not directly address the propriety of Marathon's "cross-netting" of revenues attributable to one property against obligations relating to a different property. 1776 had sought to add a breach of contract claim on that issue after the trial court's pleading deadline had passed, and the court of appeals upheld the trial court's denial of 1776's motion for leave to amend. In addition to noting that 1776's objections to the computation of Marathon's damages, which the court discussed at length, appeared to rest on an assumption that Marathon's cross-netting was improper, which 1776's unamended pleadings did not support, it observed that 1776 had not shown that the mere fact of Marathon's cross-netting would permit reasonable people to disagree about whether Marathon was entitled to recover the amounts awarded to it. *Id.* at *22.

Court of Appeals Affirms Judgment That Pipeline Company Breached Balancing Agreement

The court in *American Midstream (Alabama Intrastate), LLC v. Rainbow Energy Marketing Corp.*, No. 01-20-00055-CV, 2023 WL 2920282 (Tex. App.—Houston [1st Dist.] Apr. 13, 2023, no pet. h.), considered a gas transportation agreement dated March 1, 2015, referred to by the parties and the court as the MAG-0005, under which American Midstream (Alabama Intrastate), LLC (AMID), agreed to provide to Rainbow Energy Marketing Corporation (Rainbow), a natural gas trading company, firm balancing services and transportation of certain quantities of natural gas on its Magnolia pipeline, a small gas pipeline located in Alabama connected to the larger Transco pipeline connecting Texas to Pennsylvania. The agreement, supplementing a separate agreement for transporting Rainbow's gas, enabled Rainbow to make a daily delivery nomination of up to 20,000 MMBtu at the point of connection of the Magnolia pipeline to the Transco pipeline without a corresponding receipt nomination, and vice-versa, as long as its deliveries and receipts balanced at the end of a given month. At issue was Section 9.1 of the MAG-0005, which provided that Rainbow would not be obligated to balance receipts and deliveries of gas on a daily basis "unless, on or for any Day, either [AMID] or [Rainbow] is requested or required by an upstream or downstream party to balance receipts and deliveries of gas attributable to [Rainbow]" and, in a second sentence, that

> [i]f [AMID] is requested or required by an upstream or downstream party to balance receipts or deliveries of gas that are attributable to [Rainbow], [AMID] may cease receiving gas from or delivering gas to or for [Rainbow] until the upstream or downstream party no longer requests or requires [AMID] to balance receipts and deliveries of [Rainbow's] gas.

Id. at *4. In return for AMID's commitment to provide the services, Rainbow agreed to pay a specified sum per MMBtu of the gas allowed under the contract regardless of whether it used the services, amounting to over $1 million per year.

AMID's deliveries from the Magnolia pipeline to the Transco pipeline were subject to an operational balancing agreement (OBA) in which AMID and Transco agreed to procedures for balancing between nominated levels of service and actual quantities moving through the Transco pipeline from specified delivery and receipt points, including the interconnect with the Magnolia pipeline. The OBA obligated AMID to resolve imbalances created at the Magnolia–Transco interconnect due to differences in quantities of gas scheduled to be delivered and those actually measured. Transco could limit imbalances if they exceed 5% of total nominations and created operational concerns. Beginning in January 2016, Transco began policing imbalances at the Magnolia–Transco interconnect more strictly than it had previously, issuing notices that, while not specifically directed to parties like AMID that had an OBA in place and not expressly directing either AMID or Rainbow to take action, prompted AMID to refuse nominations by Rainbow on several occasions in January and February 2016 and afterward to inform Rainbow that its full 20,000 MMBtu would not be available. In a December 7, 2016, telephone call AMID representatives stated that it "would like to keep our imbalance under the radar with Transco" and that AMID's daily commitment under the MAG-0005 would be interruptible (subject to curtailment) rather than firm. *Id.* at *8. On February 1, 2017, Rainbow notified AMID that it was terminating the MAG-0005. Rainbow then sued AMID for breach of contract, fraud, and negligent misrepresentation, and AMID counterclaimed for breach of contract by Rainbow. After a bench trial the court awarded Rainbow $6,145,215.89 in damages, including interest, mostly for its lost profits due to inability to depend on the pipeline capacity that the MAG-0005 would have afforded.

The court of appeals agreed with the trial court's conclusion that Section 9.1 of the MAG-0005 excused AMID from providing the balancing service only if Transco either (1) requested or required AMID to balance schedule quantities with physical deliveries of gas at the Magnolia-Transco interconnect or (2) requested or required Rainbow or AMID to balance Rainbow's receipt and deliveries on Transco where use of MAG-0005 would create an imbalance between Rainbow's scheduled receipts and scheduled deliveries on Transco. In doing so it rejected AMID's argument that the trial court's references to "scheduled" receipts and deliveries and "physical deliveries" had erroneously narrowed the circumstances in which Section 9.1 excused its performance. *Id.* at *14. The first sentence implicated a "point-to-point" imbalance—an imbalance between receipts scheduled into the pipeline and deliveries scheduled out of it—that comported with the trial court's construction that AMID was excused if a party like Transco requested Transco or AMID to balance Rainbow's scheduled receipts and scheduled deliveries on Transco. *Id.* at *15. The second sentence, according to the court, implicated a single-point or operational imbalance between the amount of gas scheduled to move through a point like the Magnolia–Transco interconnect and the amount of gas actually measured there—which also comported with the trial court's construction that AMID was excused if Transco requested or required AMID to balance scheduled quantities with physical deliveries. *Id.*

Contrary to AMID's argument, the court said, none of Transco's notices had referenced gas attributable to Rainbow as creating an imbalance on the Transco pipeline. *Id.* at *17. Those had stated that parties with an OBA, like AMID, were not subject to them, and Rainbow had presented evidence that it had a pooling agreement with Transco that required Rainbow always to balance its receipts and deliveries on the Transco pipeline so that no imbalance could possibly be attributed to Rainbow. *Id.* An AMID representative had testified, the court observed, that it could have met its obligations to Rainbow through means such as purchasing or selling gas from other parties but had not considered doing so. *Id.* The court also disagreed with AMID's assertion that its "advice" given to Rainbow that Rainbow limit nominations did not constitute a breach because it did not actually curtail Rainbow's nominations. *Id.* Evidence indicated that AMID's communications could not be considered "advice" that Rainbow could disregard. *Id.* According to testimony of AMID's scheduler, shippers like Rainbow were expected to comply with his instructions. *Id.* at *18. AMID's unequivocal statements to Rainbow that it was no longer able to perform under the MAG-0005, the court concluded, had repudiated the agreement so that Rainbow was within its rights to terminate it. *Id.*

Summary Judgment for Mineral Purchaser on Seller's Fraud Claim Reversed

The court in *Baxsto, LLC v. Roxo Energy Co.*, No. 11-21-00183-CV, 2023 WL 3010965 (Tex. App.—Eastland Apr. 20, 2023, no pet. h.), reversed the trial court's summary judgment for Roxo Energy Company, LLC (Roxo), and its affiliates, who had been sued for fraud by Baxsto, LLC (Baxsto), in inducing Baxsto to lease and then sell its mineral interests in land in Howard and Borden Counties, Texas.

Baxsto had granted Roxo an option to acquire an oil and gas lease on the land for bonus consideration of $5,000 per net acre. During negotiations Roxo's representatives had told Baxsto that sum was the highest Roxo would pay to any mineral owner, and the parties agreed to include in their lease a "most-favored nations" clause providing that if Roxo paid a larger per-acre lease bonus to another lessor in the area covered by the lease within six months of the lease date, it would pay Baxsto the greater bonus. Roxo also allegedly asserted that it intended to drill the acreage itself and had obtained the funding to do so. After exercising the lease option on part of the acreage, Roxo informed Baxsto that its capital commitment to develop the acreage had been reduced and that it would lower its bonus offers to other lessors. Roxo and Baxsto then negotiated a purchase of the Baxsto mineral interest in the land for $15,126 per net acre. After the sale Baxsto claimed that Roxo had misrepresented the lease bonus amounts it was willing to pay others, the amount of funding it was prepared to commit to developing the land, and whether it intended to "flip" the interest acquired from Baxsto rather than drilling on the land, as well as that Roxo would not place a memorandum of Baxsto's lease of record until after paying Baxsto the bonus, which Roxo had violated. Those misrepresentations, according to Baxsto, had induced it to sell its minerals for much less than it otherwise would have agreed to accept. The trial court granted summary judgment to Roxo, and Baxsto appealed.

Roxo contended there was no evidence that it knew its alleged representations to Baxsto were false when made, or that the statements were made recklessly without knowledge of the truth, as required to establish fraud. *Id.* at *7. Baxsto had produced more than a scintilla of evidence on each misrepresentation, however, according to the court, notably the circumstantial evidence that Roxo paid a much higher per-acre lease bonus than Baxsto's to at least one other lessor not long after the parties' agreement for the sale and purchase of the minerals and before it had closed and that Roxo in fact did not drill on the land but sold the interests it had acquired. *Id.* at *8.

The court agreed with Baxsto that Roxo failed to show, as it argued, that Baxsto's reliance on Roxo's misrepresentations was demonstrably unjustified. The parties' contracts, particularly the oil and gas lease they negotiated, did not directly contradict the representations, in the court's view. *Id.* at *16. That was true notwithstanding that the parties' lease did not commit Roxo to any drilling obligation but made development optional, that it expressly permitted the lease to be assigned, and that its most-favored nations clause was limited in duration. *Id.* Nor did Baxsto's status as a sophisticated party in an arm's-length transaction mean that it could not justifiably rely on oral representations that did not become part of the parties' final agreement. *Id.* at *17.

Title to Non-Operated Working Interest by Adverse Possession Upheld

The court in *PBEX II, LLC v. Dorchester Minerals, L.P.*, No. 07-21-00212-CV, 2023 WL 3151830 (Tex. App.—Amarillo Apr. 28, 2023, no pet. h.), affirmed summary judgment for Dorchester Minerals, L.P. (Dorchester), against PBEX II, LLC, the assignee of Torch Oil & Gas Company (Torch), and other claimants in a suit filed by Torch to establish its leasehold title under a 1982 oil and gas lease covering an undivided 25% mineral interest in a section of land in Midland County, Texas.

Felmont Oil Company (Felmont) had been the original lessee, and it had joined in an operating agreement with other working interest owners in the land. The operator then drilled two producing gas wells that extended the term of the lease. In 1989 Torch succeeded to the interest of Felmont, and in 1990 Torch conveyed some interest in the section of land to Dorchester's predecessors-in-interest, the extent of which the parties disputed. The operator thereupon issued a new division order reducing Torch's interest to zero, which Torch signed. From 1990 until September 21, 2016, Dorchester and its predecessors-in-interest paid their shares of costs, received their shares of working interest production, paying royalty to the lessors, and made elections under the operating agreement, all without any participation by Torch. On the latter date in 2016 Torch sent Dorchester a letter stating that it had mistakenly notified the operator that it had assigned its leasehold working interest in the property in 1990. Torch filed suit when Dorchester refused to cooperate by executing a correction to confirm Torch's retention of the working interest.

The court of appeals agreed with Dorchester that it had established title to the Torch working interest under the 25-year statute of limitations. Contrary to the plaintiffs' position, the working interest was a possessory interest subject to adverse possession. *Id.* at *5. There is no distinction under Texas law between "operating" and "non-operating" working interests, the court declared—all working interests are possessory. *Id.* And it made no difference that only the operator, not Dorchester and the predecessors to its interest, had physically conducted operations on the land. *Id.* at *6. The fact that operations had been conducted and that Dorchester and its predecessors had acted as owners of the Torch working interest for over 26 years was an act sufficiently hostile to Torch's title to establish adverse possession. *Id.* at *7. Nor did the fact that the operating agreement expressly disclaimed any agency relationship between Dorchester and the operator have any bearing, according to the court, which compared the operator's role to that of a tenant with the owner's consent to use and possess the land. *Id.* at *8.

WYOMING – OIL & GAS

Jamie Jost & Amy Mowry, Reporters

Wyoming Legislature Removes State and Federal Land Exchange Acreage Requirement

A bill introduced in the Wyoming Senate, Senate File No. 128, 2023 Wyoming Laws ch. 116, was passed into law effective July 1, 2023, amending Wyo. Stat. Ann. § 36-1-105 to remove an equal-size requirement for any land parcels exchanged between the state and federal governments. The Act further makes any state and federal land exchange expressly subject to the statutory orders, rules, and regulations related to land exchanges under Wyo. Stat. Ann. § 36-1-111. As before, "the state shall not give both surface and mineral rights with any lands exchanged unless it receives the same from the federal government." *Id.* § 36-1-105.

CANADA – OIL & GAS

Greg Johnson, Jason Roth, Ashley White, Michael Smith, Marshall Eidinger, Brendan Sigalet, Evan Hall & David Wainer, Reporters

Budget 2023: Canada's Approach to Attracting Decarbonization Investment

The Government of Canada tabled the federal budget for 2023 (Budget 2023) on March 28, 2023. There are three key pillars to the Budget: (1) making life more affordable, (2) stronger public health and dental care, and (3) growing a green economy. The Budget also partly serves as Canada's response to the incentives provided for clean energy technology adoption in America's Inflation Reduction Act of 2022 (IRA).

The Government of Canada continued their drive to decarbonize the economy through use of the carrot rather than the stick by announcing two new investment tax credits: (1) the Clean Electricity Investment Tax Credit (Clean Electricity ITC), and (2) the Clean Technology Manufacturing Tax Credit (Clean Manufacturing ITC). Budget 2023 also provided further detail regarding the Clean Hydrogen Investment Tax Credit (Clean Hydrogen ITC), originally promised in fall 2022. These incentives will join two previously announced tax investment credits for clean energy technology, the Carbon Capture, Utilization and Storage Tax Credit (CCUS Tax Credit) and the Clean Technology Investment Tax Credit (Clean Tech ITC). They are intended to further incentivize the adoption of clean energy technology to assist in Canada's goal of a net-zero economy by 2050 as codified in law by the *Canadian Net-Zero Emissions Accountability Act*, SC 2021, c 22, and as further set out in the federal government's "2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy" released last year.

<u>Proposed Tax Credits</u>

Clean Electricity ITC

The Budget proposes a 15% refundable tax credit for eligible investments in clean electricity, including:

- non-emitting electricity-generating systems, such as wind, solar, hydro, wave, tidal, and nuclear (including large-scale and small modular nuclear reactors (SMRs));
- abated natural gas-fired electricity generation;
- stationary electricity storage systems that do not use fossil fuels in operation, such as batteries;
- refurbishment of existing facilities; and
- equipment for transmission of electricity between provinces and territories.

Clean Manufacturing ITC

The Budget also proposes a 30% refundable tax credit for investments in new machinery and equipment used in eligible activities generally aimed at manufacturing or processing of equipment and property used in certain clean technologies, or extracting, processing, or recycling key critical minerals, including:

- manufacturing of certain renewable and nuclear energy equipment, including nuclear fuel rods, and processing of recycling of nuclear fuels and heavy water;
- electrical energy storage equipment for grid-scale storage;
- zero-emission vehicles manufacturing (including on-road vehicle conversion) and manufacturing batteries, fuel recharging systems, and hydrogen refueling stations for zero-emission vehicles;
- upstream components that are designed exclusively to be integral to other eligible clean technology manufacturing, such as cathode materials and batteries for electric vehicles; and
- extraction of critical minerals essential for clean tech supply chains—specially, lithium, cobalt, nickel, graphite, copper, and rare earth minerals.

The critical mineral component of this credit complements another investment tax credit announced by the federal government in 2022, the Critical Mineral Exploration Tax Credit, which provides a 30% tax credit for eligible expenses to incentivize the exploration for critical minerals. *See* Vol. 40, No. 1 (2023) of this *Newsletter*.

Clean Hydrogen ITC

Canada's Clean Hydrogen ITC will be available in respect of the cost of purchasing and installing equipment for projects that produce all, or substantially all, hydrogen from their production processes, not taking into account any carbon dioxide (CO_2) produced, or any excess electricity that is sold to the grid. The tax credit will provide a tiered refundable tax credit, with projects that produce the cleanest hydrogen receiving the highest tax credit. Blue hydrogen could be eligible for a tax credit of 15 to 25%, and the cleanest hydrogen, green hydrogen, would be eligible for a 40% tax credit.

It is notable that the hydrogen tax incentives appear to outpace those provided by the IRA, which was passed in August 2022 and also offered a tiered tax credit for clean hydrogen production.

CCUS Tax Credit

The CCUS Tax Credit incentivizes the expansion of CCUS technologies to reduce emissions in high-emitting sectors, and aims to offset the purchase and installation costs for eligible equipment. The credit is offered on a sliding scale on the cost of purchasing or installing eligible equipment, provided that equipment is used for an eligible use, as follows:

- 60% for eligible capture equipment used in a "direct air capture project";
- 50% for other eligible capture equipment; and
- 37.5% for eligible transportation, storage, and use equipment.

These incentive amounts are halved in 2031 to 30%, 25%, and 18.75%, respectively. Notably, use of CO_2 for enhanced oil recovery is not an "eligible use" under the CCUS Tax Credit, which puts Canada at a competitive disadvantage with the United States (which permits a tax credit for CO_2 used for enhanced oil recovery).

Clean Tech ITC

The Clean Tech ITC will be a refundable tax credit equal to 30% of the capital cost of eligible equipment, including:

- electricity-generation systems, such as solar photovoltaic, SMRs, and concentrated solar, wind, and water systems;
- stationary electricity storage systems that do not use fossil fuels in their operation;
- low-carbon heat and electricity equipment; and
- industrial zero-emission vehicles, such as heavy-duty equipment used in mining or construction.

There is significant overlap between the Clean Electricity ITC, the Clean Tech ITC, the Clean Hydrogen ITC, the Clean Manufacturing ITC, and the CCUS Tax Credit. Budget 2023 clarifies that only one ITC can be claimed with respect to any particular property; however, it also notes that different ITCs can be claimed on different expenditures within the same project. For example, a clean hydrogen project for the production of blue hydrogen contains property that may be covered by the Clean Hydrogen ITC, as well as other property covered by the CCUS Tax Credit. Budget 2023 confirms that the Clean Hydrogen ITC may be claimed with respect to the Clean Hydrogen ITC-eligible equipment, while the CCUS Tax Credit may be claimed with respect to the CCUS Tax Credit-eligible equipment.

Responding to the IRA

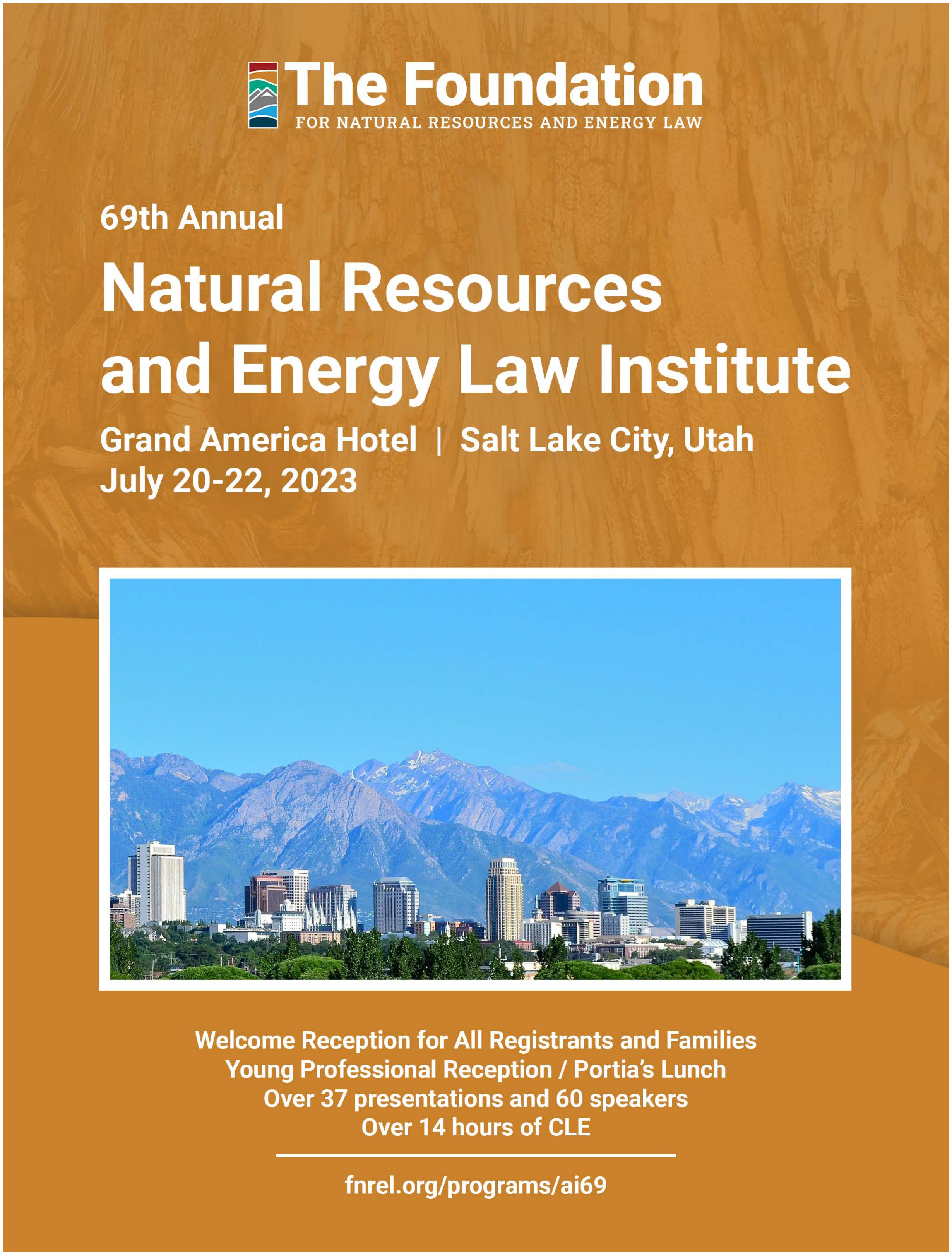
The tax incentives appear to be one response to the IRA, which brought fears that Canadian investments would dry up and make capital investments harder to obtain. While the IRA commits approximately US$369 billion in tax incentives and increased spending toward decarbonization, Budget 2023 commits approximately $20 billion over five years to decarbonization. Accounting for the GDP of both countries, these amounts represent roughly equivalent investments.

While the Canadian ITCs may be viewed by some investors as more generous and appealing than their IRA counterparts, the production tax credits used in the IRA may be more attractive to investors overall. The IRA production tax credits generate a capital return on units of alternative energy produced, offsetting uncertainty that may arise with new technologies, such as hydrogen.

To counteract such risk, Budget 2023 stated that the Canada Growth Fund will be used to provide contracts for difference. The Canada Growth Fund (capitalized with C$15 billion) was originally introduced in Canada's federal 2022 budget and is a public funding tool to attract private capital to accelerate the deployment of technologies required to decarbonize and grow the Canadian economy. While Canada's carbon price is scheduled to rise by C$15 per tonne on an annual basis until it reaches C$170 per tonne in 2030, contracts for difference provide certainty to the market as any reduction in the price on carbon (for example, if a future government minimizes the price on carbon) will not negatively impact companies, as they would then be made whole by such contracts for difference.

Conclusion

Overall, Budget 2023 and the IRA provide two different, yet substantial, attempts to incentivize decarbonization and spur investment in their respective jurisdictions. Budget 2023 provides ITCs and certainty with respect to carbon pricing, while the IRA provides production tax credits and a larger gross amount of money set aside. The IRA and Canada's federal tax incentives set the two countries to compete to attract investment for decarbonization activities; however, both provide exciting opportunities for industry to capitalize on the global push to net-zero by 2050.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