The Foundation
FOR NATURAL RESOURCES AND ENERGY LAW
FORMERLY ROCKY MOUNTAIN MINERAL LAW FOUNDATION

fnrel.org

MINERAL AND ENERGY LAW Newsletter

Volume 43 | No. 3 | 2026

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D.C. District Court Remands Gulf of Mexico Lease Sale 259 Without Vacatur After Finding NEPA Deficiencies

In *Healthy Gulf v. Burgum*, No. 1:23-cv-00604, 2026 U.S. Dist. LEXIS 112996 (D.D.C. May 21, 2026), the U.S. District Court for the District of Columbia rejected mootness arguments and remanded without vacatur the Bureau of Ocean Energy Management's (BOEM) approval of Gulf of Mexico Lease Sale 259, holding that (1) BOEM's 2026 record of decision (ROD) reaffirming the sale did not moot the litigation and (2) both *Allied-Signal* factors—seriousness of deficiencies and disruptive consequences—counseled against vacatur.

BOEM conducted Lease Sale 259 on March 29, 2023, after the Inflation Reduction Act (IRA) mandated that the sale occur no later than March 31, 2023. *Id.* at *3–4. The sale authorized leasing of 13,600 blocks covering approximately 73.3 million acres in

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FERC Directs Six Regional Grid Operators to Justify or Reform Large Load Interconnection Rules

On June 18, 2026, the Federal Energy Regulatory Commission (FERC) issued show cause orders to six FERC-jurisdictional regional transmission organizations (RTOs) and independent system operators (ISOs), aiming to spur efforts to integrate data centers and other large loads with the interstate transmission grid. *See, e.g.*, Order Instituting Proceeding Under Section 206 of the Federal Power Act, 195 FERC ¶ 61,212 (June 18, 2026). The RTOs and ISOs include PJM Interconnection, LLC; Midcontinent Independent System Operator, Inc.; Southwest Power Pool, Inc.; California Independent System Operator Corporation; ISO New England Inc.; and New York Independent System Operator, Inc. (NYISO). *Id.* The show cause orders, sent individually to each mar-

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The Vanishing Draft EIS: How Federal Agencies Are Rewriting Public Participation Under NEPA

The National Environmental Policy Act (NEPA) requires federal agencies to prepare a "detailed" environmental impact statement (EIS) for "major federal actions significantly affecting the quality of the human environment," 42 U.S.C. § 4332(2)(C), if those significant effects are "reasonably foreseeable," *id.* § 4336(b)(1). For more than four decades, the draft EIS was a fixture of this process: an agency published a draft EIS, invited public comment, and answered those comments in a final EIS. That sequence was never spelled out in NEPA itself; instead, it lived in the Council on Environmental Quality's (CEQ) implementing regulations at 40 C.F.R. §§ 1502.9 and 1503.1. In February 2025, CEQ issued an interim final rule rescinding those regulations,

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the Gulf of Mexico. *Id.* In a prior summary judgment decision, the court held that BOEM's 2023 supplemental environmental impact statement (EIS) failed to take a "hard look" at greenhouse gas emissions because it relied on outdated modeling that did not account for the IRA's policy effects. *Id.* at *4. The court also faulted BOEM's analysis of impacts on the endangered Rice's whale, whose habitat range in the Gulf was broader than BOEM acknowledged. *Id.* at *4–5. At the parties' request, the court invited separate briefing on the appropriate remedy. *Id.* at *5.

After the conclusion of remedy briefing but before the court issued a decision, BOEM completed a 2025 EIS and issued a 2026 ROD reaffirming Lease Sales 259 and 261 based on updated emissions data and a new National Marine Fisheries Service biological opinion regarding Rice's whale. *Id.* at *6–7. BOEM then argued that the 2026 ROD mooted the remedy proceedings. *Id.* at *8. The court disagreed, reasoning that the 2026 ROD "reaffirm[ed]" rather than superseded the 2023 approval, and BOEM continued to rely on the 2023 EIS for post-leasing decisions. *Id.* at *9–10. Because the original approval remained operative, the court found it could still grant effectual relief. *Id.* at *8–9. The court distinguished *Theodore Roosevelt Conservation Partnership v. Salazar*, 661 F.3d 66 (D.C. Cir. 2011), in which the court found that a subsequent ROD superseded the original "in its entirety" and rendered the case moot. *Healthy Gulf*, 2026 U.S. Dist. LEXIS 112996, at *10–11.

Applying the D.C. Circuit's *Allied-Signal* two-part framework, the court remanded without vacatur. *Id.* at *11–18 (citing *Allied-Signal, Inc. v. U.S. Nuclear Regulatory Comm'n*, 988 F.2d 146, 150–51 (D.C. Cir. 1993)). On "the seriousness of the order's deficiencies (and thus the extent of doubt whether the agency chose correctly)," the court found that the 2026 ROD demonstrated a "strong likelihood" that BOEM could substantiate its decision on remand, having updated both its emissions model and its Rice's whale analysis. *Id.* at *11–14. On "the disruptive consequences of an interim change that may itself be changed," the court found that even partial vacatur would harm lessees that collectively paid almost $250 million for leases, paid substantial rents, performed surveys, planned facilities, contracted with third parties, and invested over $135 million in data licenses and vendor work. *Id.* at *14–17. The court also noted that post-lease development requires additional environmental review and that lease terms mandate compliance with updated biological opinions, mitigating environmental risk absent vacatur. *Id.* at *17–18.

No party appealed the decision.

District of North Dakota Affirms IBIA's Dismissal of a Mineral Lease Dispute on the Fort Berthold Reservation

In *Prima Exploration, Inc. v. U.S. Department of the Interior*, No. 1:25-cv-119, 2026 U.S. Dist. LEXIS 135415 (D.N.D. June 2, 2026), *appeal docketed*, No. 26-2149 (8th Cir. June 10, 2026), the U.S. District Court for the District of North Dakota affirmed the Interior Board of Indian Appeals' (IBIA) dismissal of Prima Exploration, Inc.'s (Prima) administrative appeal for lack of standing. Prima's administrative appeal concerned two Bureau of Indian Affairs (BIA) decisions finding that Prima did not hold leasehold interests in minerals on the Fort Berthold Indian Reservation. *Id.* at *10. The court agreed with the IBIA that, based on the chain of title to the disputed mineral lease, Prima failed

The *Mineral and Energy Law Newsletter* is compiled by Professors John S. Lowe and Mark S. Squillace, and edited jointly with The Foundation for Natural Resources and Energy Law. The Foundation distributes the *Newsletter* electronically on a complimentary basis to Foundation members and on a paid circulation basis, four issues per year (print version on request); 2026 price—$125 per year.

to demonstrate a legally protected interest adversely affected by the agency's decisions and therefore lacked standing to challenge them. *Id.* at *27–28.

The dispute concerned the Rose Hopkins Hand Lease, a mineral lease approved by the BIA in 1952 covering 320 acres in McKenzie County, North Dakota, on land held in trust for Indian allottees. *Id.* at *2. The lease stated that if it was "divided by assignment of an entire interest in any part," each part would be considered a separate lease. *Id.* at *2–3. Commercial production began in 1958 from two wells in the Bakken formation, and a third source of production began in 1962 from the Madison formation through the Antelope-Madison Unit. *Id.* at *3. Bakken production ceased in 1993, while Antelope-Madison Unit production continued. *Id.* at *3–4. Prima maintained it held an operating rights interest in the lease as to the Bakken and Sanish formations, which it purportedly received in 1999. *Id.* at *2.

Prima initially challenged a 2013 BIA decision finding that the commitment of a portion of the lease to the Antelope-Madison Unit caused the lease to segregate into a second lease, which covered Prima's interest and had terminated. *Id.* at *10. Prima's appeal, however, caused the Great Plains Regional Director, in 2018, to retroactively approve a 1969 assignment from Pan American to Clinton Oil Company (Clinton Assignment) that purported to transfer Pan American's entire record title interest in the lease as to the Bakken and Sanish formations. *Id.* at *4–5. Although the assignment was recorded in the county records, the BIA had not approved it. *Id.* at *5.

The Regional Director considered the Clinton Assignment in Prima's appeal and then found that this assignment segregated the lease by geologic formation, with one lease covering the Bakken and Sanish formations and a second covering all other formations. *Id.* at *11. The Regional Director further determined that the newly formed lease covering the Bakken and Sanish formations expired when production from the Bakken formation ceased in 1993—before Prima acquired its purported interest in 1999. *Id.* at *11–12. The Regional Director then held that, because Prima lacked an interest in the lease, it did not have standing to challenge the BIA's 2013 decision. *Id.* at *12.

Prima appealed the Regional Director's approval of the Clinton Assignment and his dismissal of Prima's challenge to the 2013 BIA decision to the IBIA. Before the IBIA, Prima disputed the Regional Director's assessment of Prima's interest. *Id.* at *12–13. Prima contended that its interest in the lease stemmed from a 1971 transfer of operating rights to the Bakken and Sanish formations from Pan American to Clinton Oil Company (1971 Transfer). *See id.* at *6–7. Under Prima's theory, the Clinton Assignment was invalid and the lease never segregated by geologic formation. *See id.* Therefore, the Antelope-Madison Unit held the lease after production in the Bakken ceased in 1993, and Prima acquired an operating rights interest in the lease as to the Bakken and Sanish formations. *See id.*

The IBIA dismissed Prima's appeals in 2025 for lack of standing, reasoning that under either the Regional Director's theory or Prima's theory—i.e., if the lease segregated and Prima acquired interests in an expired lease, or if the lease did not segregate and Prima acquired operating rights to the Bakken and Sanish formations—Prima lacked a legally protected interest sufficient to confer standing to appeal the Regional Director's decisions. *Id.* at *12–13. The IBIA found that the Regional Director reasonably concluded that the Clinton Assignment, if valid, segregated the Bakken or Sanish formations into a second lease that had expired for lack of production. *Id.* at *12–13. The IBIA reasoned that Prima then lacked an interest in an active lease and thus standing to challenge the BIA's 2013 decision. *See id.* at *13. Alternatively, the IBIA determined that, even if the BIA improperly approved the Clinton Assignment and Prima held an operating rights interest in the lease as to the Bakken and Sanish formations, this interest was insufficient to confer standing "in this instance." *Id.* at *13; *see also id.* at *24 (finding that the assignment of operating rights did not confer to Prima "the right to stand in the shoes of the lessee to appeal" (quoting *Prima Exploration, Inc.*, 70 IBIA 288, 304 (2025))).

Reviewing the IBIA's decision under the Administrative Procedure Act's arbitrary-and-capricious standard, the district court affirmed. *Id.* at *15–28. The court held that the IBIA rationally concluded Prima lacked standing under either construction of the title chain. *Id.* at *18–25.

Prima had particularly challenged the IBIA's finding that Prima's purported operating rights interest did not confer standing. First, Prima argued that the IBIA improperly applied judicial standing principles that were more restrictive than the IBIA's standing regulation. *Id.* at *20 (citing 25 C.F.R. § 2.2). The court rejected Prima's argument, noting the IBIA's long-standing use of judicial standing principles in administrative appeals. *Id.* at *22. Second, Prima argued that the IBIA erroneously concluded that Prima's operating rights did not confer standing. *See id.* at *20. The court, however, upheld as reasonable the IBIA's finding that Prima's purported operating rights interest in the lease did not carry "the authority to represent the lessee in issues affecting the interests of the [lease]." *Id.* at *24.

The court declined to address whether the BIA acted properly by retroactively approving the Clinton Assignment, because the IBIA had dismissed solely on standing grounds without reaching the merits. *Id.* at *25–28 (citing *Motor Vehicle Manufacturers Ass'n v. State Farm Mutual Automobile Insurance Co.*, 463 U.S. 29 (1983)).

Prima has appealed the decision to the U.S. Court of Appeals for the Eighth Circuit.

IBLA Holds Offshore Lessees' Decommissioning Obligations Accrue Before Lease Assignment

In *Devon Energy Corp.*, IBLA Nos. 2021-0132 et al. (2026), the Interior Board of Land Appeals (IBLA) affirmed three Bureau of Safety and Environmental Enforcement (BSEE) orders finding that Devon Energy Corp., ConocoPhillips Co., and Oxy U.S.A. Inc. (collectively, Appellants), as prior lessees or successors-in-interest, had each accrued decommissioning obligations before assigning their record title interests in an offshore oil and gas lease.

Prior to 1991, the Appellants or their predecessors had held interests in Lease OCS-P 0166 ("the Lease"), which was issued in 1967 and is located on the Outer Continental Shelf in waters near Santa Barbara, California. *Id.* at 3. In 1991, Signal Hill acquired the Lease and Pacific Operators Offshore, LLC (POOLLC) became the designated operator. *Id.* at 4. The transfer instrument established an escrow account for decommissioning

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.

costs. *Id.* In 2020, Signal Hill relinquished the Lease, claiming neither it nor POOLLC could perform decommissioning. *Id.* On November 6, 2020, BSEE ordered the Appellants to submit decommissioning plans. *Id.* at 7. The appeals were consolidated. *Id.* at 1.

The issue on appeal was whether BSEE erred in determining that the Appellants had accrued decommissioning obligations from their Lease interests and operations prior to assigning them to Signal Hill. *Id.* at 8. BSEE maintained the Appellants had accrued decommissioning obligations under the Lease terms and regulations in effect in 1991, when the Appellants assigned their interests, and under regulations later promulgated in 1997. *See id.* The Appellants argued that decommissioning obligations do not accrue until lease termination, which could not have happened before 1991, and that applying 1997 regulations would be unlawful because the Lease did not incorporate future regulations. *Id.* at 8–9.

Relying on the Lease language and *Anadarko Petroleum Corp.*, 187 IBLA 77, GFS(OCS) 268(2016), *reconsideration denied*, 188 IBLA 127, GFS(OCS) 271(2016), the IBLA held that the Appellants accrued decommissioning obligations while holding record title and conducting operations, which were not extinguished by their 1991 assignments. *Id.* at 9–14. In *Anadarko*, the IBLA found Anadarko liable for decommissioning activities following assignment of its leasehold interests, for two reasons. First, the relevant lease in *Anadarko* required lessees to remove "all devices, works, and structures" within one year of lease termination. *Id.* at 10 (citing 187 IBLA at 83). Second, although Anadarko assigned its interest in 1984, a 1997 regulation imposed decommissioning obligations on Anadarko because the lease provided that the lessee was subject to "future regulations." *Id.* at 10–11 (citing 187 IBLA at 87; 30 C.F.R. § 256.62 (1997)).

As in *Anadarko*, the IBLA held that the Appellants retained their decommissioning obligations after assignment. *Id.* at 12. The IBLA found that, like the *Anadarko* lease, the Lease required lessees to complete decommissioning within one year after Lease termination. *Id.* at 11–12 (citing Lease § 6). Additionally, the IBLA found that other language in the Lease reinforced the lessees' liability, including a statement that a lessee has a "continued obligation . . . to abandon all wells on the area to be relinquished." *Id.* (citing Lease § 5).

The IBLA rejected the Appellants' attempt to discredit the *Anadarko* decision on the ground that it did not consider "common law understandings" of, or the Department of the Interior's past interpretations of, the term "accrue." *See id.* at 11, 13, 14–21. The IBLA also rejected the Appellants' attempt to distinguish the language of the Lease from the lease at issue in *Anadarko*. *See id.* at 12. The Appellants had argued that, whereas the lease in *Anadarko* subjected lessees to all "future regulations," the Lease lacked this language. Nonetheless, the IBLA found that Lease language requiring compliance with "*all* lawful and reasonable regulations" included future regulations, *id.* at 22–23 (emphasis added) (citing Lease at unp. 1), because other Lease terms were limited to "regulations in force and effect on the date of issuance of this lease," *id.* (citing Lease § 7). Thus, the reference to "all" regulations was not limited to those in effect in 1967. *Id.* at 23 (citing *Amoco Prod. Co.*, 10 IBLA 215, 219, GFS(O&G) 44(1973)).

Finally, the IBLA rejected the Appellants' arguments that BSEE's orders were arbitrary or capricious because lessees cannot perform the required decommissioning in the prescribed timeframes. The IBLA found that the deadlines were standard and reasonable and that BSEE indicated willingness to grant extensions or consent stays. *Id.* at 25–26.

The IBLA reached its decision in a 26-page dispositive order, which the IBLA maintains is not precedent. *See id.* at 1. Although not precedent, dispositive orders nonetheless provide guidance to lessees as to how the IBLA and BSEE may address similar issues in the future.

At the time of this report, no Appellant appears to have sought administrative reconsideration of the decision or judicial review.

John H. Bernetich & Dale Ratliff, Guest Reporters

District of Montana Vacates a Third Round of Oil and Gas Leases in Greater Sage-Grouse Habitat

In *Montana Wildlife Federation v. Burgum*, No. 4:18-cv-00069, 2026 WL 1707576 (D. Mont. June 12, 2026), the U.S. District Court for the District of Montana vacated nearly all oil and gas leases sold at the February, September, and December 2019 Bureau of Land Management (BLM) Wyoming lease sales and the March and December 2019 Montana/Dakota lease sales. The court found that BLM failed to apply a requirement in its 2015 resource management plans (RMPs) requiring BLM offices to prioritize fluid mineral leasing and development in outside sage-grouse habitat (the "Priority Requirement"). *See id.* at *1, *6. The court vacated all of the challenged leases *not* held by production, but declined to vacate nine leases determined to be held by actual production. *Id.* at *12. The court also declined to vacate leases offered for sale at the December 2020 Wyoming lease sale, which had yet to be issued, and for which "no final agency action exists to vacate or remand." *Id.*

The decision resolves the third phase of an ongoing challenge by a coalition of nongovernmental organizations to a series of BLM oil and gas lease sales across multiple states pursuant to 2015 RMPs and BLM's Instruction Memorandum No. 2018-026 (IM 2018-026). IM 2018-026 directed BLM to apply the 2015 RMPs' Priority Requirement only where a "backlog" of leasing nominations existed. *Id*. at *1.

In Phase One, the court vacated IM 2018-026 and three Montana and Wyoming lease sales for failing to properly apply the 2015 RMPs' Priority Requirement. *Id.* The court "determined that [IM 2018-026] unreasonably misconstrued the purpose of the 2015 Plans' prioritization requirements and rendered the prioritization requirement into a mere procedural hurdle." *Id.* (internal quotation marks omitted). The U.S. Court of Appeals for the Ninth Circuit affirmed. *Id*. at *3. In Phase Two, the court found five additional lease sales in Nevada and Wyoming violated the Federal Land Policy and Management Act (FLPMA) for the same reason. *Id.* at *2. This *Newsletter* detailed the Phase One and Phase Two decisions in Vol. 42, No. 1 (2025), Vol. 39, No. 2 (2022), and Vol. 37, No. 3 (2020).

In the latest iteration of these challenges, Phase Three, the plaintiff groups argued that the 2019 lease sales in Wyoming, Montana, and the Dakotas violated FLPMA for the exact same reasons that the lease sales in Phases One and Two violated FLPMA, citing the Ninth Circuit's affirmation of the court's Phase One decision as dispositive. *Id.* at *3.

The defendants raised a new challenge, relying on Congress's amendments to the Mineral Leasing Act in the One Big Beautiful Bill Act (OBBBA), Pub. L. No. 119-21, 139 Stat. 72 (2025). The OBBBA defines the "eligible lands" subject to leasing as all BLM mineral lands "not excluded from leasing by a statutory prohibition . . . that have been designated as open for leasing under a land use plan . . . and that have been nominated for leasing through the submission of an expression of interest, are subject to drainage in the absence of leasing, or are otherwise designated as available pursuant to regulations adopted by the Secretary." 30 U.S.C. § 226(b)(1)(A). The defendants argued that the OBBBA amendments "echoed a preexisting understanding by Congress that the MLA always required leasing under certain circumstances," that "the standards outlined in OBBBA lessen the severity of any FLPMA violations or errors as to prioritization," and that the OBBBA "effectively mandates BLM to offer nominated parcels for lease if the parcels are open to leasing and known or believed to contain oil and gas deposits." *Montana Wildlife*, 2026 WL 1707576, at *5. The court rejected all three arguments, holding the OBBBA cannot be read to apply retroactively and the "statutory text of OBBBA does not effectively eliminate BLM's discretion so broadly as to mandate the sale and issuance of leases without oversight." *Id.*

The court vacated all of the challenged leases *not* held by production, declined to vacate nine leases determined to be held by actual production, and declined to vacate leases offered for sale at the December 2020 Wyoming lease sale yet to be issued. *Id.* at *12.

As of the date of this report, Continental Resources, Inc. and R&R Royalty, Ltd. have filed notices of appeal.

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ket, are FERC's first major response to the October 2025 rulemaking request from the U.S. Department of Energy (DOE) seeking to advance the interconnection of data centers to the interstate transmission grid, and by extension to rewrite the jurisdictional status quo on state versus federal authority over these loads. *See* Interconnection of Large Loads to the Interstate Transmission System, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025); *see also* Letter from Chris Wright, Sec'y, U.S. Dep't of Energy, Docket No. RM26-4-000 (Oct. 23, 2025).

<u>Individual Commissioner Concurrences</u>

The show cause orders came from FERC as a unified front, but Commissioners wrote separate concurrences to emphasize specific policy nuances and priorities. Chairman Swett and Commissioners Rosner, See, Chang, and LaCerte all issued individual concurring statements supporting the action.

Swett

According to Chairman Swett, "[s]imply put, the show cause orders [FERC] issue[d] . . . to each of the six electric markets subject to its jurisdiction find that the status quo across much of the country is not good enough." Chairman Swett's Remarks on the Large Load Show Cause Orders (June 18, 2026). Aside from this challenge of the current state of affairs, Chairman Swett generally issued grand statements regarding the importance of FERC's action and the sagaciousness of tackling the problem through an individualized regional approach, while also casting the action as a somewhat provocative call to arms to protect the "great industrial economy that anchors America." *Id.*

Rosner

Commissioner Rosner's remarks framed the action as "opening a dialogue with each of the six RTO/ISOs on a series of reforms," seemingly aiming to strike a milder chord. Commissioner Rosner's Remarks on the Large Load Show Cause Orders (June 18, 2026). However, the Commissioner explained further by highlighting four key pillars: "(1) Protecting Consumers, (2) Safeguarding Reliability, (3) Enhancing Transparency, and (4) Fostering Innovation." *Id.* Between calling out grid-enhancing technologies, North American Electric Reliability Corporation reforms, the issue of developers "shopping around" prospective projects with different utilities, and highlighting how the order will promote flexible transmission service concepts, the statements emphasized regulatory innovation to match a new wave of innovative large load applications. *Id.*

See

Commissioner See's statement centered on collaboration with various stakeholders—both other federal agencies, as well as states, the regional markets, and utilities—but ultimately toward a goal of "[c]reating efficient, predictable large load interconnection processes." Commissioner See's Remarks on the Large Load Show Cause Orders (June 18, 2026). More than any other commissioner, Commissioner See seemed respectful of the current paradigm and the other stakeholders that are seeking solutions to address the new large load paradigm. While indicating that affordability is at the forefront, and that protecting customers is crucial, Commissioner See also emphasized that "exercising [FERC's] authority fully without hamstringing [its] regulatory and industry partners means respecting the States." *Id.*

Chang

Commissioner Chang warned that "grid operators must also be careful not to implement changes that create unforeseen reliability risks," and as a corollary stressed the need for robust, region-specific records, noting that section 206 proceedings carry ex parte restrictions that limit informal engagement with stakeholders and state regulators. Commissioner Chang's Concurrence in ISO New England Inc. (June 18, 2026). Overall, the statesmanlike remarks focused on the need for balance among affordability, reliability, and timely interconnection for large loads. *Id.*

LaCerte

Commissioner LaCerte made remarks about the current paradigm in a gambling metaphor indicating that "[t]he stakes here could not be higher and every gambler knows that the secret to surviving is knowing what to throw away and knowing what to keep." Commissioner LaCerte's Concurrence in New York Independent System Operator, Inc. (June 18, 2026). Given the tone of the overall remarks, the Commissioner seemed the least deferential to the current status quo, going even further than Chairman Swett's "not good enough," and raising the stakes—suggesting the need to fold or "throw away" certain aspects of the large load interconnection paradigm. *Id.* Luckily, these strong and pointed remarks seemed limited in that they were directed only toward NYISO, but they also expressed a unique sense of urgency to address the problem: "Today's orders do exactly that— . . . driving meaningful change, and rejecting the gridlock, half-measures, and failure to plan that have gone on for far too long." *Id.*

<u>Conclusion</u>

The FERC Commissioners' comments continue the narrative of pushing the boundaries of FERC's jurisdiction. However, Commissioner See's theme of respect for state authority was promising, albeit somewhat unique, among the Commissioners that each saw FERC's action of issuing the show cause orders a little differently. While some Commissioners cast the proceedings as an opportunity for innovative solutions to a new technological paradigm and economic mandate, others were both more and less deferential to other stakeholders, as well as the current paradigm. Only time will tell how these orders will be received—whether they will spur meaningful progress, and whether the historical preservation of states' jurisdiction over retail loads will be maintained.

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removing the very provisions that had made the draft EIS mandatory. *See* Removal of NEPA Implementing Regulations, 90 Fed. Reg. 10,610, 10,616 (Feb. 25, 2025). CEQ adopted that rescission without change in January 2026. *See* Removal of NEPA Implementing Regulations, 91 Fed. Reg. 618 (Jan. 8, 2026). What has followed is a decentralized, agency-by-agency NEPA regime in which draft EIS publication is increasingly optional—and the adequacy of environmental review, and the scope of public participation, are once again contested questions.

With its regulatory authority removed, CEQ shifted from regulator to advisor. In a September 29, 2025, memorandum, it issued a non-binding "Agency NEPA Procedures Template" (NEPA Template) to help agencies write their own procedures. *See* 90 Fed. Reg. 47,734 (Oct. 2, 2025). In a significant shift from the prior NEPA procedures, CEQ's NEPA Template makes publication of a draft EIS optional rather than mandatory. NEPA Template at 16. In its place, agencies must solicit public comment only during scoping, following a notice of intent (NOI) to prepare an EIS—the minimum participation NEPA's text requires. *Id.* at 8. Scoping comments address project alternatives, potential effects, and relevant studies. *Id.* But information about environmental effects is necessarily thin at that early stage, before the agency has done its analysis.

<u>Response from Federal Agencies</u>

Federal agencies have moved quickly to revise or adopt their own NEPA procedures—either through guidance or regulation—and have almost uniformly adopted an approach consistent with CEQ's NEPA Template. The Department of the Interior (DOI), Department of Energy (DOE), and Department of War (DOW) have each taken steps to rescind the bulk of their existing NEPA regulatory frameworks in favor of department-wide guidance documents. *See* 91 Fed. Reg. 8737 (Feb. 24, 2026); 90 Fed. Reg. 29,676 (July 3, 2025); 90 Fed. Reg. 27,857 (June 30, 2025). These departmental procedures drop the draft EIS requirement while retaining public scoping on the NOI and giving responsible agency officials discretion to include additional public involvement as warranted. DOI expressly concluded that NEPA requires public comment at "one and only one step" in developing an environmental document—the NOI—and that DOI otherwise retains discretion to seek public comment on draft environmental documents. 91 Fed. Reg. at 8752; *see* DOI, "Handbook of NEPA Procedures," at 3 (Feb. 2026). DOE and DOW have adopted similar discretionary approaches. *See* DOE, "National Environmental Policy Act (NEPA) Implementing Procedures," at 15, 31 (July 13, 2026); DOW, "National Environmental Policy Act Implementing Procedures," at 20 (Apr. 30, 2026).

The Department of Agriculture (USDA) has taken a slightly different path, adopting department-wide NEPA regulations at 7 C.F.R. pt. 1b and rescinding its component-specific regulations. 91 Fed. Reg. 17,062 (Apr. 3, 2026). Like the NEPA procedures discussed above, the USDA's revised NEPA regulations permit—but do not require—a draft EIS while preserving the NOI comment request. 7 C.F.R. § 1b.7. Similarly, the Nuclear Regulatory Commission (NRC) has proposed revised NEPA regulations under which the NRC would discontinue preparation and publication of draft EISs, including the routine solicitation of public comments on draft EISs. 91 Fed. Reg. 42,086, 42,093 (July 7, 2026).

The notable outlier is the Federal Energy Regulatory Commission (FERC). FERC revised its core NEPA procedures to strip out cross-references to the rescinded CEQ regulations and stand up an independent framework, but its Staff Guidance Manual confirms that FERC will continue to issue a draft EIS and solicit comment. FERC, "Staff Guidance Manual on Implementation of the National Environmental Policy Act," at 10 (June 2025). For practitioners, FERC's choice is a useful reminder that "decentralized" does not mean "uniform"—the draft EIS survives in some corners of the federal government and not others.

<u>Remaining Procedural Questions</u>

Agencies whose regulations allow for skipping public participation at the draft EIS stage are now faced with determining what level of public participation is left at the end of the NEPA process. Some agencies have taken the stance that there is no public participation post-EIS. For example, in its 2026 NOI for the Bear Lodge Rare Earth Project, the Forest Service indicated it will not publish a draft EIS or conduct an objections process, leaving no opportunity for the public to comment on the completed EIS before the issuance of a record of decision (ROD). Black Hills National Forest; Wyoming; Bear Lodge Rare Earth Project, 91 Fed. Reg. 47,803, 47,803 (July 29, 2026) (notice of intent).

Agencies that are choosing to allow public participation are left with a different challenge—compressing public participation into the narrow window between the final EIS and the ROD—typically only 30 days. Agencies that accept draft comment responses in that window may squeeze the project proponent out of a review process it has historically helped improve. The agency's options in that window are limited: fold the responses into the ROD, or—if a comment surfaces an issue requiring further analysis—trigger a supplemental EIS that will almost certainly run longer than a draft EIS and comment period would have in the first place. Where nongovernmental organizations (NGOs) marshal competing expert analyses on a 30-day clock, the uncertainty lands precisely when it is most costly: operators by then may have time-critical execution plans, contractors carrying stand-down exposure, and capital commitments keyed to seasonal restrictions.

<u>Early Challenges and the Fate of Ninth Circuit Precedent</u>

Environmental NGOs have already begun to raise legal challenges to this revised approach to NEPA implementation. For example, at the South Railroad Mine—a proposed gold and silver mine in Elko County, Nevada—the Bureau of Land Management (BLM) published an NOI to prepare an EIS and solicited scoping comments. 90 Fed. Reg. 38,988 (Aug. 13, 2025). In response, several NGOs submitted comments insisting that BLM "must publish a draft EIS on which the public is allowed to meaningfully participate," and warning that skipping straight to a final EIS both frustrates NEPA's "twin aims" and departs from settled precedent from the U.S. Court of Appeals for the Ninth Circuit.

That precedent is not trivial. Even absent an express statutory command, the Ninth Circuit has long treated draft EIS publication and comment as essential to NEPA's purpose. In *California v. Block*, the court held that NEPA's public comment procedures are "at the heart of the NEPA review process." 690 F.2d 753, 770 (9th Cir. 1982). Only when a draft EIS circulates, the court reasoned, can the public analyze a proposal and comment; no comparable right exists once a final EIS issues, and denying it "renders NEPA's procedures meaningless." *Id.* at 771. Several courts—primarily in the Ninth Circuit—have cited *Block* for this proposition and its related principles. *See, e.g.*, *Half Moon Bay Fishermans' Mktg. Ass'n v. Carlucci*, 857 F.2d 505, 508 (9th Cir. 1988); *Ctr. for Biological Diversity v. Bernhardt*, 982 F.3d 723, 734 (9th Cir. 2020); *W. Expl., LLC v. U.S. Dep't of the Interior*, 250 F. Supp. 3d 718, 748 (D. Nev. 2017); *Town of Abita Springs v. U.S. Army Corps of Eng'rs*, 153 F. Supp. 3d 894, 917 (E.D. La. 2015).

Whether this precedent survives the new framework remains uncertain, and practitioners should resist confident predictions in either direction. On one hand, rescinding a regulation does not by itself displace binding circuit precedent. A three-judge panel remains bound by prior authority unless intervening higher authority is "clearly irreconcilable" with it. *Miller v. Gammie*, 335 F.3d 889, 893 (9th Cir. 2003) (en banc). And *Loper Bright Enterprises v. Raimondo* reinforces that settled precedent resists displacement by a fresh agency interpretation of statute. 603 U.S. 369, 403 (2024). On the other hand, there is a real argument the other way: *Block* and its progeny arguably construed a regulatory obligation, not a statutory one, and may be distinguishable now that the regulation is gone. Even so, a court could still conclude that NEPA's "twin aims" are best served by public comment on a draft EIS—when impacts are actually understood—rather than at the NOI scoping stage.

<u>Lingering Litigation and Remedy Concerns</u>

The challenges are not confined to project-specific scoping letters. Several lawsuits have been filed challenging how agencies have rescinded their existing NEPA regulations. *See Ctr. for Biological Diversity v. U.S. Dep't of Interior*, No. 3:25-cv-10793 (N.D. Cal.); *Ctr. for Biological Diversity v. U.S. Dep't of Agric.*, No. 3:26-cv-00866 (N.D. Cal.). These cases target the process itself: failure to provide notice and comment, failure to give a reasoned explanation, and failure to respond adequately to public comment. If successful, these cases would result in reinstatement of the prior regulations—including the draft EIS mandate.

For agencies and operators, the remedy phase is where a procedural misstep can become an operational crisis. If a court holds that NEPA requires a draft EIS with public comment, remand *without* vacatur will be a hard sell. The agency would need record evidence that the omission was harmless—i.e., that it would have reached the same result regardless. That may prove difficult where a design alternative or mitigation measure surfaces during the compressed interval between a final EIS and the ROD.

<u>Practical Takeaways</u>

For practitioners advising in this environment, several points warrant attention:

- Know the governing agency's NEPA procedures. Each agency has different implementing procedures and regulations, which can lead to varying requirements for projects.
- Consider voluntarily building in a draft-EIS-style comment step. When an agency has discretion to add public involvement, counsel for operators may find that doing so is cheaper than a supplemental EIS or a vacatur remedy.
- Treat scoping as the critical—and possibly only—early participation opportunity and develop a robust administrative record that can support a harmless-error argument if the omission of a draft EIS is later challenged.
- Watch the pending rescission and project-level litigation closely. A ruling reinstating prior regulations or reaffirming *Block*-style participation requirements would reset expectations across every ongoing EIS-level review.

Editor's Note: The reporters represent parties involved in both the NEPA environmental review process and NEPA litigation, and the views expressed here are their own and do not necessarily reflect those of any client.

CONGRESS/FEDERAL AGENCIES

John H. Bernetich & Dale Ratliff, Reporters

BLM Rescinds Conservation and Landscape Health Rule

On May 12, 2026, the Bureau of Land Management (BLM) rescinded its Biden-era 2024 Conservation and Landscape Health Rule (Conservation Rule). The Conservation Rule, published on May 9, 2024, represented a significant change in BLM's land management framework under the Federal Land Policy and Management Act (FLPMA). Conservation and Landscape Health, 89 Fed. Reg. 40,308 (May 9, 2024) (to be codified at 43 C.F.R. pts. 1600, 6100). As previously reported in Vol. 41, No. 2 (2024) of this *Newsletter*, the now-rescinded Conservation Rule had three principal components: it identified "conservation" as a "use" under FLPMA, revised BLM's procedures for designating areas of critical environmental concern (ACECs), and created new restoration and mitigation leases as conservation tools. *See id.* at 40,308–10. BLM's Rescission Rule became effective June 11, 2026. *See* Rescission of Conservation and Landscape Health Rule, 91 Fed. Reg. 25,787 (May 12, 2026) (to be codified at 43 C.F.R. pts. 1600, 6100) (Rescission Rule).

<u>Conservation as a "Use"</u>

The Conservation Rule defined "conservation" as "the management of natural resources to promote protection and restoration." 89 Fed. Reg. at 40,339. BLM stated that conservation was a "use on par with other uses of the public lands under FLPMA's multiple-use and sustained-yield mandate." *Id.* at 40,308.

In the Rescission Rule, BLM stated that the Conservation Rule "inappropriately elevated conservation as a discrete use of public lands," contrary to FLPMA's intent and statutory framework. 91 Fed. Reg. at 25,788. The rescission "restores balance" to public land management under FLPMA by reaffirming multiple-use and sustained-yield principles, ensuring conservation does not restrict productive uses or impede efficient decision making. *Id.* at 25,787.

<u>Restoration and Mitigation Leases</u>

A central feature of the Conservation Rule was conservation leases. The Conservation Rule created two types of leases: restoration and mitigation leases. 89 Fed. Reg. at 40,327. Restoration leases could be used to facilitate restoration of degraded land and resources, and mitigation leases could be used to offset impacts to resources resulting from other land-use authorizations. *Id.*

The Rescission Rule eliminates restoration and mitigation leasing. 91 Fed. Reg. at 25,788. BLM stated that these mechanisms "threatened to restrict productive use of public lands" and introduced "uncertainty and unnecessary burdens in planning and permitting." *Id.* BLM determined that existing authorities and tools remain sufficient to address conservation objectives without imposing new prescriptive mandates or timelines. *Id.* In response to comments, BLM stated that FLPMA authorizes BLM to allow third parties to "use, occupy, and develop" public lands, but does not provide authority for the type of conservation leasing established by the Conservation Rule. *Id.*; *see also* 43 U.S.C. § 1732(b).

ACECs and Land Health Standards

The Conservation Rule required authorized officers to identify, evaluate, and give priority to areas that have potential for ACEC designation during the land-use planning process. 89 Fed. Reg. at 40,325. The Conservation Rule created a presumption that potential ACECs that meet relevance, importance, and special management attention criteria would be designated. *Id.*

The Rescission Rule restores the prior ACEC regulations to the framework in place since 1983. 91 Fed. Reg. at 25,788. BLM asserts that ACEC designations should remain site-specific, based on appropriate relevance and importance criteria, and integrated into land-use planning decisions. *Id.*

Public Comments and BLM's Response

Commenters supporting rescission argued the Conservation Rule was overly restrictive, economically harmful, inconsistent with FLPMA, and likely to interfere with productive uses of public lands. *Id.* at 25,788. Commenters opposing rescission argued that the Conservation Rule was necessary to address ecosystem resilience, habitat connectivity, climate adaptation, watershed health, and tribal engagement. *Id.* at 25,790–91.

BLM concluded that rescission was consistent with FLPMA and current national energy policy. *Id.* at 25,794. The Rescission Rule cites executive and secretarial direction concerning energy development and deregulation, including Executive Order No. 14,154, "Unleashing American Energy," and Executive Order No. 14,156, "Declaring a National Energy Emergency." *Id.*

Implications for Mineral Development

The Rescission Rule does not immediately and directly affect federal oil and gas leasing or hardrock mining. But the Rescission Rule may affect the amount of land available to lease or location by removing the presumption of ACEC designation for lands meeting specified criteria. The rescission may also reduce regulatory uncertainty for prospective lessees. BLM planners may no longer rely on the conservation-as-use framework or restoration and mitigation lease provisions when weighing conservation against development proposals. *Id.* at 25,788. In this respect, the Rescission Rule "remove[s] any thumb on the scale in favor of conservation at the expense of productive use and development of the public lands and their many important resources." *Id.*

FWS Finalizes ESA Rules Restoring Regulations from the First Trump Administration

On July 21, 2026, the U.S. Fish and Wildlife Service (FWS) published two final rules revising its Endangered Species Act (ESA) regulations. The first eliminates FWS's "blanket 4(d) rule," which provided FWS the default option to automatically apply all species rules applicable to endangered species to listed threatened species. Regulations Pertaining to Endangered and Threatened Wildlife and Plants, 91 Fed. Reg. 45,723 (July 21, 2026) (to be codified at 50 C.F.R. pt. 17). The second revises FWS's framework for deciding whether to exclude areas from critical habitat designations. Regulations for Designating Critical Habitat, 91 Fed. Reg. 45,662 (July 21, 2026) (to be codified at 50 C.F.R. pt. 17). Both rules took effect on August 20, 2026.

The final rules are two of four ESA rule revisions proposed by FWS on November 21, 2025, part of an effort to return FWS's ESA regulations to those in effect at the close of the first Trump administration. *See* Vol. 43, No. 1 (2026) of this *Newsletter*. The rules proposed revisions to the blanket section 4(d) rule, criteria for excluding critical habitat, interagency consultation under section 7, and the standards for listing, delisting, and designating critical habitat. *See* Regulations Pertaining to Endangered and Threatened Wildlife and Plants, 90 Fed. Reg. 52,587 (proposed Nov. 21, 2025) (to be codified at 50 C.F.R. pt. 17); Regulations for Designating Critical Habitat, 90 Fed. Reg. 52,592 (proposed Nov. 21, 2025) (to be codified at 50 C.F.R. pt. 17); Interagency Cooperation Regulations, 90 Fed. Reg. 52,600 (proposed Nov. 21, 2025) (to be codified at 50 C.F.R. pt. 402); Listing Endangered and Threatened Species and Designating Critical Habitat, 90 Fed. Reg. 52,607 (proposed Nov. 21, 2025) (to be codified at 50 C.F.R. pt. 424). The two recently published final rules adopt the first two proposals. The section 7 consultation rule and the listing, delisting, and designation rule remain pending. FWS has stated it anticipates finalizing both in the coming months. *See* FWS, "Endangered Species Act Regulation Revisions," https://www.fws.gov/project/endangered-species-act-regulation-revisions.

Section 4(d) "Blanket Rule"

As explained in Vol. 43, No. 1 (2026) of this *Newsletter*, section 9(a) of the ESA lists prohibitions that apply automatically to endangered species at the time of listing but does not extend those same prohibitions automatically to threatened species. 91 Fed. Reg. at 45,724; *see also* 16 U.S.C. §§ 1533(d), 1538(a). Section 4(d) instead directs the Secretary of the Interior to issue such regulations as are "necessary and advisable" for the conservation of threatened species and authorizes the Secretary to extend section 9 prohibitions to them. 91 Fed. Reg. at 45,724. Under the blanket 4(d) rule, FWS would automatically extend nearly all endangered-species prohibitions to threatened species unless it adopted a species-specific section 4(d) rule. *Id.*

The final rule adopted on July 21 removes the blanket-rule option for species newly listed as threatened, or reclassified from endangered to threatened, after August 20, 2026. *Id.* at 45,724–25. FWS will instead be required to establish protections through species-specific section 4(d) rules focused "on the stressors contributing to the threatened status of the species." *Id.* at 45,724–25. FWS concluded that tailored rules can reduce permitting burdens, facilitate conservation actions, and improve predictability in section 7 consultations. *Id.* at 45,724–26.

The final rule largely adopts the November 2025 proposal but declines to require FWS to finalize a species-specific section 4(d) rule concurrently with a listing or reclassification decision. *Id.* at 45,725. FWS explained that concurrent issuance remains its intended practice, noting that when the blanket rule was unavailable from 2019 through 2024, it issued interim or final species-specific rules concurrently for all 46 species then listed or reclassified as threatened. *Id.* The final rule also departs from the proposal in one significant respect: it will not change existing protections for species currently listed as threatened, which the proposed rule had contemplated. *Id.* Existing blanket-rule protections remain in place until FWS completes a separate rulemaking for the affected species, which FWS intends to review during periodic status reviews under section 4(c)(2). *Id.* Each future species-specific rule must include a "necessary and advisable" determination, consider conservation and economic impacts, and receive public comment. *Id.* at 45,724–25.

Critical Habitat Exclusions

The second rule establishes an FWS-specific framework for excluding areas from critical habitat under section 4(b)(2) of the ESA. *See* 91 Fed. Reg. at 45,664; *see also* 16 U.S.C. § 1533(b)(2). As noted in Vol. 43, No. 1 (2026) of this *Newsletter*, the prior regulations neither required FWS to conduct an exclusion analysis in response to a proponent's comments nor identified factors to guide that analysis. The final rule directs FWS to conduct an exclusion analysis when a proponent presents credible information demonstrating a meaningful economic or other relevant impact supporting exclusion of a particular area, or when the Secretary otherwise elects to evaluate an area. 91 Fed. Reg. at 45,669.

The rule permits FWS to consider impacts to tribes, states, local governments, public health and safety, community interests, federal lands, conservation plans and partnerships, and environmental management, including wildfire and invasive-species management. *Id.* at 45,666–67. FWS will also consider the area's current conservation function and its future recovery value. *Id.* at 45,667. If the benefits of exclusion outweigh the benefits of inclusion, FWS must exclude the area unless exclusion will result in the species' extinction. *Id.* at 45,664.

FWS finalized the exclusion regulations substantially as proposed, making only two non-substantive word changes. The final rule replaces "the FWS's expertise" with "the Service's expertise" for consistency, and changes "assign" to "give" in describing the weight afforded to information—a change FWS explained avoids any suggestion that it will numerically quantify the weight of impacts during an exclusion analysis. *Id.*

ARIZONA – OIL & GAS

Andrea J. Driggs, Reporter

ACC Developments

ACC Explores Next Steps After Attorney General Disapproves REST Repeal Package

On June 1, 2026, the Arizona Corporation Commission (ACC) announced that it had authorized its Office of General Counsel to explore future actions after the Attorney General disapproved the Commission's Renewable Energy Standard and Tariff (REST) repeal package. *See* Press Release, ACC, "ACC to Explore Options After Disapproval of Renewable Energy Standard and Tariff Rulemaking Package" (June 1, 2026). The ACC stated that, during a May 28, 2026, Staff Open Meeting, it discussed the status of the REST repeal and the Gas Utility Energy Efficiency Standard repeal packages that had been delivered to the Attorney General for review under Ariz. Rev. Stat. § 41-1044. The ACC further stated that the Attorney General approved and transmitted the Gas EE repeal but disapproved the REST repeal on the ground that the ACC allegedly violated its own rulemaking process. The ACC characterized the issue as implicating its Arizona Constitution article 15 ratemaking authority over public service corporations.

ACC Continues Nuclear Generation Workshops and Utilities Begin Preliminary Siting Study

On June 25, 2026, the ACC held its third workshop in its "Advancing Nuclear Power Generation" series, and on June 29, 2026, it announced that the workshop reflected increasing momentum for additional nuclear power in Arizona. *See* Press Release, ACC, "Closer to Reality: Workshop Reveals Increasing Momentum for Additional Nuclear Power in Arizona; Preliminary Study Underway to Assess Possible Sites for New Generation Plant" (June 29, 2026). The ACC reported that Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), and Salt River Project (SRP) had launched a joint preliminary siting study to identify a potential location for new nuclear generation in Arizona. The ACC described the workshop as addressing water availability, supply-chain risks, workforce development, education, and community engagement. The workshop was docketed under ACC Docket No. E-00000A-25-0026.

The practical impact is that new nuclear generation has moved from general policy discussion into early siting analysis by Arizona's three largest utilities. No application for a certificate of environmental compatibility or other project authorization was identified, so this remains a planning-stage development. Practitioners should nevertheless monitor the workshop docket, because water, workforce, supply-chain, site-control, community-engagement, and cost-recovery issues are likely to shape any future certificate, rate-base, or state ratemaking proceeding involving new nuclear generation.

ACC Repeals Electric Energy Efficiency Standards Rules

On July 8, 2026, the ACC voted 4–0 to repeal the Electric Energy Efficiency Standards Rules, Ariz. Admin. Code tit. 14, ch. 2, art. 24. *See* Press Release, ACC, "ACC Repeals Outdated Electric Energy Efficiency Standards Rules, Related Surcharges to be Eliminated in Phases" (July 8, 2026). The ACC stated that the rules had created an unjust subsidy through uniform surcharges, that the rules had served their purpose, and that the market had advanced since the rules were adopted in 2010. The ACC also stated that current Commission-approved demand-side management and energy-efficiency programs will continue, while related surcharges may be phased out individually in future rate cases or by ACC order. The ACC directed staff to prepare a notice of final rulemaking package and file necessary documents with the Secretary of State for publication and codification in Docket No. RE-00000A-24-0025.

The practical impact is that Arizona's regulated electric utilities no longer face a generally applicable statewide electric energy-efficiency mandate under Article 24, but they may continue to seek approval and cost recovery for particular demand-side management or energy-efficiency programs. This shifts energy-efficiency review from a rule-based mandate toward case-by-case utility planning, procurement, and ratemaking proceedings. Developers, aggregators, and customer-side energy-efficiency providers should expect greater emphasis on cost-effectiveness, rate design, and utility-specific evidentiary showings rather than reliance on a statewide savings target.

ACC Approves Springerville Generating Station Unit 4 Coal-to-Gas Conversion Amendment

At its July 8, 2026, open meeting, the ACC approved an amendment to the Certificate of Environmental Compatibility for the Springerville Generating Station to allow conversion of Unit 4 from coal-fired to natural-gas-fired boilers. *See* ACC, "July 8, 2026 Open Meeting Highlights" (July 10, 2026). The ACC's meeting highlights identify the matter as involving TEP and docket references L-00000C-86-0000-00074 and L-00000C-010074. The ACC stated that Unit 4 is owned by SRP and that Units 1 and 2, owned by TEP, were already approved for the same conversion. The ACC also reported public comments from local and business representatives supporting the conversion as a way to preserve jobs, revenue, economic stability, and reliable baseload power.

The practical impact is that Arizona continues to repurpose existing coal-generation infrastructure for natural-gas-fired operation rather than relying only on new-build gas generation. The approval also preserves a role for the Springerville site in Arizona's baseload-resource mix while coal operations decline.

ACC Approves TEP Santa Rita Connection Project Certificate

At the same July 8, 2026, open meeting, the ACC approved a Certificate of Environmental Compatibility for TEP's Santa Rita Connection Project, Docket No. L-00000C-26-0125-00261. *See* ACC, "July 8, 2026 Open Meeting Highlights" (July 10, 2026). The project involves construction of a 13- to 17-mile 138 kV transmission line connecting TEP's existing Sonoran Substation in Pima County to TEP's planned Santa Rita Substation in Santa Cruz County. TEP's project page states that the Arizona Power Plant and Transmission Line Siting Committee voted to recommend approval of the CEC application after a public hearing held in May 2026. *See* Tucson Elec. Power, "Santa Rita Connection Project," https://www.tep.com/santa-rita-connection. TEP states that the project is intended to increase energy capacity and enhance system reliability for customers in Sahuarita, Green Valley, and the surrounding area.

The project is significant because it addresses reliability constraints in a growth area south of Tucson while also drawing public concern about co-location with infrastructure serving the Copper World mine. TEP's counsel told the ACC that co-location would reduce environmental impact and save ratepayers money, and the ACC's summary states that the new line will not be used to serve the mine.

Arizona Legislature Supports Next-Generation Geothermal Roadmap

Although House Concurrent Resolution 2057 was filed with the Secretary of State on April 21, 2026, the Arizona House issued a May 1, 2026, release announcing final legislative approval and emphasizing the resolution's support for geothermal energy development. *See* H.C.R. 2057, 57th Leg., 2d Reg. Sess. (Ariz. 2026); Press Release, Ariz. House of Representatives, "Rep. Teresa Martinez: Arizona Should Lead on Reliable Geothermal Energy" (May 1, 2026). The resolution states that Arizona's changing energy landscape includes semiconductors, advanced manufacturing, data centers, and other high-load growth industries. It also states that Arizona utilities anticipate that serving the state's growing population and economy will require new generation resources. The resolution supports a geothermal permitting roadmap, alignment of existing agency rules related to geothermal development, and next-generation energy resource development to support Arizona's advanced manufacturing economy.

The practical impact is that the legislature has created a policy marker for interagency geothermal permitting coordination, even though the resolution does not itself enact a binding permitting program. The Arizona Oil and Gas Conservation Commission regulates oil, gas, helium, carbon dioxide, and geothermal drilling and production, with the relevant rules in Ariz. Admin. Code tit. 12, ch. 7. The resolution identifies multiple Arizona agencies that may have roles in future geothermal development, including the Oil and Gas Conservation Commission, the Department of Environmental Quality, the Department of Water Resources, and the Corporation Commission. Developers should treat geothermal as an emerging Arizona energy issue that will require coordinated water, drilling, environmental, utility, and siting approvals.

CALIFORNIA – OIL & GAS

Tracy K. Hunckler, Megan A. Sammut & Katie Y. Eng, Reporters

California Supreme Court Clarifies CEQA's Class 1 Exemption for Well Conversions

As last reported in Vol. 42, No. 1 (2025) of this *Newsletter*, on December 18, 2024, the California Supreme Court granted review of the First District Court of Appeal's decision to uphold the California Geologic Energy Management Division's (CalGEM) determination that converting a plugged production well into a Class II injection well qualified for the California Environmental Quality Act's (CEQA) Class 1 categorical exemption for minor alterations to existing facilities involving negligible or no expansion of use. *Sunflower All. v. Dep't of Conservation*, 559 P.3d 1082 (Cal. 2024). The court of appeal reasoned that, although the project required minor modifications to the well and related infrastructure, any expansion in use was negligible because the environmental risks associated with injecting water were negligible. *Sunflower All. v. Dep't of Conservation*, 325 Cal. Rptr. 3d 209 (Ct. App. 2024). The supreme court limited its review to two questions: (1) whether an agency may rely on a categorical exemption while imposing conditions of approval addressing potential environmental effects; and (2) whether "negligible" under the Class 1 exemption refers to the degree of change in use or the risk of environmental harm. On April 6, 2026, the supreme court heard oral argument, and the matter was submitted for decision.

On June 25, 2026, the California Supreme Court reversed the First District Court of Appeal's decision, holding that the "negligible or no expansion of existing or former use" requirement in CEQA's Class 1 categorical exemption concerns the "nature or degree" of the facility's use and not whether the proposed change presents a risk of environmental harm. *Sunflower All. v. Dep't of Conservation*, 591 P.3d 829, 843 (Cal. 2026). In reaching that conclusion, the court explained that the word "expansion" can include both changes in the degree of a use and changes in its nature. *Id.* at 841. The examples listed in section 15301 of the CEQA Guidelines, Cal. Code Regs. tit. 14, § 15301, such as adding bicycle lanes to an existing street, converting a residence to office use, or using a residence as a small family day-care home, demonstrate that some changes in use may qualify. *Sunflower All.*, 591 P.3d at 841. But the exemption does not extend to every change in use merely because the agency believes the resulting environmental risk is minimal. *Id.* A project-specific inquiry into whether environmental impacts are significant ordinarily occurs later, after the agency determines that no exemption applies. *Id.* at 845. Treating minimal environmental risk as sufficient to establish the Class 1 exemption would conflate those stages and require environmental-effects analysis before the procedures, including public participation, associated with formal CEQA review. *Id.* at 844.

The court did not decide whether the Brentwood Oil Field Ginochio Well conversion constitutes a negligible change in former use. Instead, it remanded the matter for the court of appeal to reconsider whether substantial evidence supports CalGEM's exemption determination under the proper standard. *Id.* at 846. Further, the court declined to decide the second issue on which it had granted review: Whether an agency may rely on a categorical exemption while imposing project conditions addressing potential environmental effects. *Id.* The court explained that the issue may become unnecessary depending on the court of appeal's ruling on remand. *Id.*

CBE Challenges CARB's Cap-and-Invest Amendments

Communities for a Better Environment (CBE) filed a verified petition in Los Angeles County Superior Court in July 2026, challenging the California Air Resources Board's (CARB) May 29, 2026, approval of amendments to California's cap-and-invest program. Verified Petition for Writ of Mandate and Complaint for Injunctive and Declaratory Relief, *Cmtys. for a Better Env't v. CARB*, No. 26STCP02498 (L.A. Super. Ct. July 1, 2026). The petition alleges that CARB violated the California Environmental Quality Act (CEQA) by certifying an inadequate final environmental impact assessment that failed to thoroughly analyze the amendments' environmental and public-health consequences, including the effects of substantially increasing free emissions allowances for industry, reducing revenues available for environmental programs, and disproportionately burdening low-income communities and communities of color. *Id.* It further alleges that CARB adopted significant late-stage changes without revising or recirculating the analysis, inadequately addressed public comments, and failed to consider feasible mitigation measures and alternatives. *Id.* CBE seeks a writ directing CARB to set aside its approvals and related findings, declaratory relief, and preliminary and permanent injunctive relief barring implementation of the amendments until CARB complies with CEQA. *Id.*

CARB subsequently noticed a mandatory settlement meeting by videoconference for August 17, 2026, at which the parties were expected to confer and attempt in good faith to resolve the dispute. Notice of Mandatory Settlement Meeting, *Cmtys. for a Better Env't v. CARB*, No. 26STCP02498 (L.A. Super. Ct. July 28, 2026).

AB 2716 (2026) and AB 2461 (2026) Double-Joined, Both Fail

As last reported in Vol. 43, No. 2 (2026) of this *Newsletter*, Assembly Bill 2716 (AB 2716) would have revised California's bonding and financial assurance requirements for oil and gas operators, clarified plugging and abandonment obligations, and established conditions under which wells transferred for decommissioning cannot return to production. The bill was intended to address issues attributed to Assembly Bill 1167, which imposed stringent bonding requirements upon the acquisition of the right to operate a well or production facility. After clearing the Assembly Natural Resources Committee and the Assembly Appropriations Committee, the bill passed the Assembly in late May and was sent to the Senate. The measure was referred to the Senate Natural Resources and Water Committee and formally amended and re-referred to the Senate Appropriations Committee in July.

At the same time, Assembly Bill 2461 (AB 2461) would have expanded the types of transactions that trigger bonding requirements and eliminated certain exemptions for higher-producing wells. That bill was amended and approved by the Assembly Appropriations Committee in May and moved to the Senate, where it was referred to the Senate Natural Resources and Water Committee in June, approved there with amendments, and formally amended and re-referred to the Senate Appropriations Committee in July. AB 2461 was also aimed at the unintended consequences of AB 1167 and would have extended bonding requirements to an entity that acquires an operator, where the operator does not change.

In July, both bills were respectively amended in the Senate to make each operative only if the other passed. The bills remained separate measures, but were legislatively linked such that both would pass, or both would fail. In August, both bills were held in the Senate Appropriations Committee and are effectively dead for this legislative session.

CalGEM Updates Regulations Governing Oil and Gas Operations Within Health Protection Zones

The California Geologic Energy Management Division (CalGEM) issued several notices to operators (NTOs) in June 2026, discussing significant regulation changes to oil and gas operations within health protection zones (HPZs).

On June 10, CalGEM announced that the SB 1137 First Implementation Regulations will replace the emergency regulations regarding public health and safety and environmental protection limitations on oil and gas operations within an HPZ. The previous emergency regulations, adopted in January 2023 and resumed in June 2024, were to remain in effect for two years, and set to expire in July 2026. Effective July 1, the First Implementation Regulations will continue many requirements set forth in the 2023 emergency regulations, with significant changes, additional definitions, clarifications, and enhanced descriptions to nearly all sections. The now effective regulations describe the requirements for an operator to show that a location is not within an HPZ, how to request an exception for a notice of intent (NOI) in an HPZ, and requirements for annual submittals of sensitive receptor inventories and maps.

To resolve confusion regarding the annual submittals requirement, CalGEM released a supplemental NTO on June 29, clarifying common errors in the submissions received to date. This NTO acknowledged the confusion regarding CalGEM's "Best Practices" guidance document released in June, and operators' concerns about the July 1 submission deadline. According to CalGEM, "Best Practices" does not contain new information about submittal requirements, but rather should be used to assist operators in spotting potential issues within their submittal documents. Sections 1765.6 through 1765.9 of the California Code of Regulations specify the submission requirements for the three required documents: an annual inventory specifying all CalGEM-identified potential sensitive receptors, corresponding maps, and an outside-an-HPZ statement. A "No Changes" determination statement is required when an operator has submitted an accurate and unchanged inventory, map, and out of HPZ statement in the previous year. The documentation from the previous year shall be resubmitted the following year, with the additional statement confirming no new changes have occurred. Due to the confusion, CalGEM will continue to accept 2026 annual submittals until September 1, 2026.

Lastly, CalGEM issued an additional NTO on June 22, 2026, announcing the implementation of Cal. Pub. Res. Code § 3282 requirements, effective July 1, 2026. The new regulations apply to all oil and gas production wells or facilities with wellheads within HPZs. Section 3282 requires operator compliance with all local, state, and federal laws (whichever is most stringent), chemical analysis and reporting for produced water transported from the field, immediate suspension of noncompliant production facilities, and establishes operational requirements relating to noise, light, dust, and other particulate control.

California Moves to Dismiss United States' Challenge of the State's Emission Limitations and ZEV Mandates

Earlier this year, the United States filed an action against the California Air Resources Board (CARB) alleging that CARB's carbon dioxide emissions limitations and zero emission vehicle (ZEV) mandates violate the Energy Policy and Conservation Act and the U.S. Constitution. Complaint, *United States v. CARB*, No.

2:26-cv-00847 (E.D. Cal. Mar. 12, 2026); *see* Vol. 43, No. 2 (2026) of this *Newsletter* for additional background.

In May, CARB moved to dismiss the complaint in its entirety for lack of standing. Motion to Dismiss, *United States v. CARB*, No. 2:26-cv-00847 (E.D. Cal. May 26, 2026). CARB argues that the challenged ZEV mandates terminated in 2025 and applied only to vehicle model years that had ended before the action was filed. *Id.* The motion alleges the claim for injury is primarily based on future hypothetical ZEV standards, warranting its dismissal. *Id.* Although California's greenhouse gas (GHG) emission standards continued past 2025, the motion asserts that the harm alleged is not specific to the emission standards, but rather is tied to both the ZEV and GHG standards simultaneously. *Id.* CARB argues that the United States did not allege injury at the time of implementation of the GHG standards, but instead waited 14 years to claim "sovereign harm." *Id.* The hearing on the motion to dismiss is set for August 27, 2026.

New Oil Ordinances Move Forward in Los Angeles City and County

Since our last update on the City of Los Angeles' proposed oil and gas drilling ordinance consistent with Assembly Bill 3233 of 2024, *see* Vol. 43, No. 1 (2026) of this *Newsletter*, the Los Angeles Planning and Land Use Management Committee approved City Planning's recommendation to adopt the new ordinance and related environmental documents at a meeting on June 9, 2026, and transmitted the matter to the Energy and Environment Committee, which waived consideration of the item on June 18. *See* Council File No. 17-0447-S2. Thereafter, on June 23, the proposed ordinance went before the entire City Council, which adopted the proposed environmental document and instructed the City Attorney to prepare and present the ordinance for City Council consideration. If adopted by City Council and signed by the Mayor, the new ordinance will make existing oil wells a nonconforming use, ban the drilling of new wells, and prohibit the maintenance of existing wells except under a limited health and safety exception. These actions have been subject to numerous comment letters challenging the legality of the City's actions, including based on grounds asserted in litigation on the prior failed ordinance, which attempted to impose similar measures.

In the County of Los Angeles, a draft environmental impact report (DEIR) has now been prepared and published on the County website, dated July 2026. As set forth in the executive summary of the DEIR, the project consists of not only the proposed ordinance to prohibit new wells and phase out existing wells, but also an amendment to the County's General Plan to remove policies that support oil production. If approved, the ordinance will apply throughout the unincorporated areas of Los Angeles County, except for the lands within the California Coastal Zone.

Editor's Note: The reporters serve as counsel for Warren E&P, Inc., Warren Resources of California, Inc., and Warren Resources, Inc., and represented the Warren entities in their administrative appeals and lawsuit against the City of Los Angeles in the litigation as to the prior failed ordinance.

Ongoing Disputes over Sable Offshore's California Operations

<u>State Parks Action Against Sable over Pipeline Operations at Gaviota State Park</u>

As last reported in Vol. 43, No. 2 (2026) of this *Newsletter*, on March 17, 2026, California State Parks (State Parks) sued Sable Offshore Corp. (Sable) in state court, alleging that Sable restarted and continued operating an oil pipeline through Gaviota State Park after the underlying easement expired in 2016 and beyond the limited scope of temporary access permits. The complaint seeks to halt operations, require removal of the pipeline, and obtain declarations that Sable has no continuing property or operational rights in the park. Complaint for Injunctive Relief and Declaratory Relief, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 26CV01759 (Santa Barbara Super. Ct. Mar. 17, 2026).

After removal to federal court, State Parks sought a preliminary injunction based on alleged ongoing trespass and harm to public lands, while Sable raised statute-of-limitations, estoppel, and federal-preemption defenses under the Pipeline Safety Act and a Defense Production Act order. Notice of Motion and Motion for Preliminary Injunction, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. Mar. 27, 2026); Opposition to Plaintiff's Motion for Preliminary Injunction, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. Apr. 3, 2026). Meanwhile, the United States moved to intervene on May 5, 2026, arguing that an injunction would interfere with federally required or protected pipeline operations and that intervention was necessary to defend federal supremacy, national-defense, and critical-energy interests. Notice of Motion and Motion to Intervene, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. May 5, 2026).

On May 28, 2026, the court denied State Parks' motion for preliminary injunction, finding State Parks did not establish irreparable harm because the pipeline's use caused no demonstrated tangible injury, could be compensated with damages, presented no imminent environmental risk, and did not deprive State Parks of regulatory authority vested in the Office of the State Fire Marshal. Minute Order, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. May 28, 2026). On June 3, the court granted the United States' request to intervene.

Sable's answer denies the trespass claims and asserts that operations resumed under the Defense Production Act order, that any claim accrued when the easement expired in 2016, and that the claims are barred by estoppel under a consent decree, acquiescence, unclean hands, and federal preemption. Defendants Sable Offshore Corp. and Pacific Pipeline Company's Answer to Complaint, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. May 18, 2026). The United States likewise denies liability and asserts preemption under the Defense Production Act, Pipeline Safety Act, Commerce Clause, and Import-Export Clause, as well as estoppel and lack of entitlement to equitable relief. Defendant-Intervenor United States of America's Answer to Plaintiff's Complaint, *Cal. Dep't of Parks & Recreation v. Sable Offshore Corp.*, No. 2:26-cv-02946 (C.D. Cal. June 10, 2026).

<u>Environmental Defense Center and Center for Biological Diversity Lawsuits on Pipeline Waivers</u>

As last reported in Vol. 43, No. 2 (2026) of this *Newsletter*, the Environmental Defense Center (EDC) and Center for Biological Diversity (CBD) continue to pursue parallel challenges to state pipeline safety waivers that allegedly allowed Sable to restart its pipeline without required environmental review or public participation. *Env't Def. Ctr. v. Cal. Dep't of Forestry & Fire Prot.*, No. 25CV02247 (Santa Barbara Super. Ct. Apr. 15, 2025); *Ctr. for Biological Diversity v. Cal. Dep't of Forestry & Fire Prot.*, No. 25CV02244 (Santa Barbara Super. Ct. Apr. 15, 2025). In July 2025, the court issued a limited preliminary injunction allowing restart only after Sable confirmed compliance with required approvals and provided 10 days' notice. Order, *Ctr. for Biological Diversity*, No. 25CV02244 (Santa Barbara Super. Ct. July 29, 2025). The court later denied Sable's requests to reconsider or dissolve the injunction, concluding that the Pipeline and Hazardous Materials Safety Administration's (PHMSA) assertion of jurisdiction and Sable's preemption arguments did not eliminate its obligations under the federal consent decree to obtain authorization from the California Office of the State Fire Marshal (OSFM). Motion for Consideration of Preliminary Injunction, *Ctr. for Biological Diversity*, No. 25CV02244 (Santa Barbara Super. Ct. Jan. 5, 2026); Minute Order, *Ctr. for Biological Diversity*, No. 25CV02244 (Santa Barbara Super. Ct. Feb. 27, 2026); Minute Order, *Ctr. for Biological Diversity*, No. 25CV02244 (Santa Barbara Super. Ct. Apr. 17, 2026).

On May 14, 2026, the United States and Sable removed the consolidated cases to federal court, arguing that the April 17 order placed Sable between conflicting directives: a state injunction requiring compliance with the federal consent decree and a Defense Production Act order requiring immediate pipeline operations. Notice of Removal, *Ctr. for Biological Diversity v. Cal. Dep't of Forestry & Fire Prot.*, No. 2:26-cv-05242 (C.D. Cal. May 14, 2026). The United States contends the state proceedings are effectively "directed to" the federal government because they interfere with federal operations, while Sable argues it is "acting under" a federal officer—both maintain that removal was timely because the April 17 order and related contempt proceedings crystallized the conflict and that a federal forum is needed to resolve overlapping issues involving PHMSA, the consent decree, the Defense Production Act order, immunity, and preemption. *Id.*

Sable then moved for reconsideration and dissolution of the preliminary injunction, arguing that PHMSA's designation of the Santa Ynez Pipeline System as interstate displaced OSFM's authority, nullified the challenged state waivers, and mooted the underlying claims. Notice of Motion for Reconsideration and to Dissolve Injunction, *Ctr. for Biological Diversity*, No. 2:26-cv-05242 (C.D. Cal. May 15, 2026). Sable also contends that only the issuing federal court may enforce the consent decree and that the Defense Production Act order preempts conflicting state requirements and protects federally compelled conduct. *Id.* The petitioners responded with an ex parte remand application, arguing that removal was untimely, that the action is neither "directed to" the United States nor based on Sable acting under a federal officer, and that Sable waived removal by first seeking relief in state court and removing only after an adverse ruling. Ex Parte Application, *Ctr. for Biological Diversity*, No. 2:26-cv-05242 (C.D. Cal. May 18, 2026). The court heard the remand motion on June 8, 2026; a further hearing set for June 29 was later vacated, and a ruling remains pending.

<u>Coastal Commission Lawsuit on Pipeline Work in the Coastal Zone</u>

As previously reported in Vol. 43, No. 2 (2026) of this *Newsletter*, Sable's dispute with the California Coastal Commission (Commission) remains ongoing after the Santa Barbara Superior Court ruled that the Commission had authority under the California Coastal Act to issue cease-and-desist and restoration orders and impose an $18-million penalty concerning pipeline work along the Gaviota Coast. Minute Order, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. Oct. 15, 2025).

The Commission later moved for judgment on the pleadings as to Sable's remaining claims in its second amended complaint, arguing that the October 2025 writ ruling had already upheld the validity of its April 10, 2025, enforcement orders and entitled it to judicial enforcement. Motion for Judgment on the Pleadings, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. Mar. 18, 2026). Sable opposed, contending that judgment was premature in light of the pending appeal and proposed third amended complaint, that its remaining claims raised preemption and constitutional issues not requiring exhaustion of administrative remedies, that declaratory relief remained appropriate for resolving those disputes, and that Sable was entitled to discovery on its remaining non-writ claims. Plaintiffs' Opposition to Motion for Judgment on the Pleadings to Second Amended Complaint, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. Apr. 22, 2026).

In April 2026, Sable sought leave to file a third amended complaint adding claims that PHMSA's assertion of exclusive safety jurisdiction, federal restart approvals, and a Defense Production Act order preempted the Commission's enforcement actions. Motion for Leave to File Third Amended Complaint, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. Apr. 21, 2026). Sable also sought to add a contractual interference claim, related affirmative defenses, and updated allegations, asserting the amendments were timely because the developments were new and the case was still at an early stage. *Id.*

On May 20, 2026, the court granted the Commission's motion for judgment on the pleadings as to Sable's second through fifth causes of action, which consisted of a claim for inverse condemnation and three claims for declaratory relief. The court granted judgment on those claims without leave to amend, thereby disposing of all remaining claims in Sable's second amended complaint against the Commission; however, the Commission's cross-complaint against Sable remains pending. The court also denied Sable leave to file a third amended complaint, but permitted Sable to amend its answer to the Commission's cross-complaint. Minute Order, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. May 20, 2026).

Sable's June 17 amended answer denies the Commission's enforcement claims and adds defenses based on PHMSA's asserted jurisdiction, the Pipeline Safety Act, the Defense Production Act, lack of Commission authority, mootness, and the alleged invalidity or unenforceability of the Commission's orders. Amended Answer to the California Coastal Commission's First Amended Cross-Complaint for Declaratory and Injunctive Relief, *Sable Offshore Corp. v. Cal. Coastal Comm'n*, No. 25CV00974 (Santa Barbara Super. Ct. June 17, 2026). A 10-day court trial is set for February 17, 2027.

<u>Motion to Dismiss Granted in Lawsuit Against Santa Barbara County</u>

In April, Santa Barbara County and environmental intervenors moved to dismiss portions of a federal lawsuit brought by Sable and ExxonMobil challenging the County Board of Supervisors' December 2025 denial of permit transfers for three oil and gas facilities. Notice of Motion and Motion to Dismiss Complaint in Part filed by Defendants, *Sable Offshore Corp. v. Cnty. of Santa Barbara*, No. 2:25-cv-04165 (C.D. Cal. Apr. 29, 2026). The County argues that the plaintiffs lack vested rights to the discretionary transfers and have not plausibly alleged a compensable taking, federal or state preemption, or breach of an earlier settlement agreement. *Id.* The intervenors separately target the preemption claim, contending that the Pipeline Safety Act does not displace the County's permitting authority, a subsequent Defense Production Act order neither conflicts with nor overrides County Code ch. 25B, and state spill prevention and response laws do not grant exclusive authority over the financial considerations at issue. Notice of Motion and Motion to Dismiss Seventh Cause of Action filed by Intervenors, *Sable Offshore Corp. v. Cnty. of Santa Barbara*, No. 2:25-cv-04165 (C.D. Cal. Apr. 30, 2026).

In opposition, Sable and ExxonMobil argue that the motions improperly ask the court to resolve factual disputes and disregard well-pleaded allegations. Opposition, *Sable Offshore Corp. v. Cnty. of Santa Barbara*, No. 2:25-cv-04165 (C.D. Cal. May 27, 2026). They contend that chapter 25B mandates approval once specified criteria are met, that the permits constitute vested property rights, and that the County based its denial on pipeline safety and financial matters reserved to federal and state authorities, with a Defense Production Act order creating an additional conflict. *Id.* The plaintiffs also maintain that the denial breached the 1988 Celeron Agreement and ask the court to deny both motions in full or, alternatively, grant leave to amend. *Id.*

On July 14, 2026, the court granted the County's and the environmental intervenors' motions to dismiss, but the ruling did not end the case. Minutes of in Chambers, *Sable Offshore Corp. v. Cnty. of Santa Barbara*, No. 2:25-cv-04165 (C.D. Cal. July 14, 2026). The court dismissed with prejudice Sable's takings claims and the plaintiffs' state-law preemption claim, while allowing amendment of the ExxonMobil affiliates' takings claims, the federal preemption claims under the Pipeline Safety Act and Defense Production Act, and the breach of contract claim. *Id.* The plaintiffs' four administrative writ claims challenging the Board's permit transfer decision were not subject to the motions and remain to be adjudicated. *Id.*

<u>Ruling on Demurrer and Motion to Strike in Lawsuit over Las Flores Canyon Facility</u>

As last discussed in Vol. 43, No. 2 (2026) of this *Newsletter*, on February 17, 2026, Sable filed a verified petition for writ of mandate and complaint against the California Geologic Energy Management Division (CalGEM), the California Department of Conservation, and related officials challenging CalGEM's assertion of regulatory jurisdiction over Sable's Las Flores Canyon Facility. Petition for Writ of Mandate, *Sable Offshore Corp. v. CalGEM*, No. 26WM000036 (Sacramento Super. Ct. Feb. 17, 2026). On April 15, 2026, the State filed a demurrer, arguing that the petition fails to state a claim and is not ripe because Sable has not exhausted available administrative remedies and CalGEM has not issued a final enforcement order. Demurrer, *Sable Offshore Corp. v. CalGEM*, No. 26WM000036 (Sacramento Super. Ct. Apr. 15, 2026).

On May 15, 2026, CalGEM filed a special motion to strike Sable's petition under California's anti-SLAPP statute, arguing that Sable's lawsuit arises from CalGEM's constitutionally protected regulatory communications and anticipated enforcement activity. Special Motion to Strike, *Sable Offshore Corp. v. CalGEM*, No. 26WM000036 (Sacramento Super. Ct. May 15, 2026). CalGEM contends that Sable is attempting to prevent the agency from asserting jurisdiction, demanding compliance, and pursuing enforcement before final agency action has occurred. *Id.* CalGEM further argues that Sable cannot demonstrate a probability of prevailing because the case was filed prematurely without exhaustion of administrative remedies, and Sable has alternative remedies if CalGEM later issues an enforcement order. *Id.* CalGEM maintains that Las Flores Canyon falls within its jurisdiction as it contains numerous tanks, pipelines, compressors, separators, and other equipment "attendant to" oil and gas production. *Id.* CalGEM therefore asks the court to strike and dismiss the petition in its entirety. *Id.*

On July 31, 2026, the court adopted its tentative rulings overruling CalGEM's demurrer and denying its anti-SLAPP motion to strike Sable's petition. Minute Order, *Sable Offshore Corp. v. CalGEM*, No. 26WM000036 (Sacramento Super. Ct. July 31, 2026). The court found that Sable was excused from exhausting administrative remedies because no clearly defined or adequate process existed to challenge CalGEM's assertion of jurisdiction, waiting for an uncertain citation or order would expose Sable to substantial bonding and penalty risks, and Sable presented a plausible argument that CalGEM lacked authority over the facility. Tentative Ruling, *Sable Offshore Corp. v. CalGEM*, No. 26WM000036 (Sacramento Super. Ct. July 30, 2026). The court denied CalGEM's special motion to strike, finding Sable's claims arise from CalGEM's regulatory decisions and enforcement conduct, not from protected speech despite those decisions being communicated through letters. *Id.*

SB 982 Revives SB 222's Climate-Disaster Liability Proposal

As last discussed in Vol. 42, No. 1 (2025) of this *Newsletter*, Senate Bill 222 (SB 222) was originally introduced on January 27, 2025, as a proposal to impose civil liability on certain fossil-fuel companies for damages arising from a "climate disaster or extreme weather or other events attributable to climate change," provided certain conditions are met. On January 5, 2026, however, the bill was gutted and amended, removing the climate-liability provisions and replacing them with legislation concerning residential heat-pump water heaters and heating, ventilation, and air conditioning (HVAC) systems, meaning the climate-disaster bill was dead.

Senator Wiener, however, introduced Senate Bill 982 (SB 982) on February 4, 2026, reviving and modifying the climate-disaster liability framework previously contained in SB 222. As amended on April 6, SB 982 would have authorized the Attorney General to bring civil actions against covered fossil-fuel companies—generally companies with at least $500 million in market capitalization or annual revenue—to recover climate-attributable insurance-related losses suffered by California policyholders and the California FAIR Plan. Covered companies would have been subject to strict liability without regard to fault, with liability allocated using market-share and alternative-liability principles. The bill also would have prohibited covered companies from passing litigation costs or judgments on to California consumers through fuel prices. Like SB 222, SB 982 failed passage in the Senate Judiciary Committee in April. Given the similar themes of strict liability for climate disasters, though, another similar bill may be introduced again in the next legislative session.

COLORADO – OIL & GAS

Amelia Marsh & Scott Turner, Reporters

Colorado Supreme Court Holds in Favor of Producer on Fraudulent Misrepresentation Claims

In June 2026, the Colorado Supreme Court decided *Veolia Water Technologies, Inc. v. Antero Treatment LLC*, 2026 CO 52, 591 P.3d 936. This case concerned a design/build agreement (DBA) between Veolia Water Technologies, Inc. (Veolia) and Antero Treatment, LLC (Antero). Under the DBA, Veolia agreed to build a water treatment system to treat wastewater from Antero's hydraulic fracturing operations. The system was called the "Clearwater" facility.

The DBA contained provisions requiring that (1) the product of the Clearwater system be solid and stable, and thus suitable for landfill disposal; and (2) the Clearwater system satisfy certain power consumption limits. Shortly before signing the DBA, Veolia discovered that it had miscalculated the facility's daily power requirements by a significant margin and began to redesign the system to reduce its power demand. Veolia did not inform Antero of this miscalculation or the subsequent redesign, and the parties signed the DBA. Eight days after the original DBA was signed, Veolia proposed, and Antero agreed to sign, a Change 1 order modifying the original design. Veolia was aware that this changed design could change the character of the wastewater but did not inform Antero.

Two years after the DBA was signed, the Clearwater system began treating wastewater. However, the product was not solid as promised, but rather a "soupy salt," contrary to the terms of the DBA. At this time, Veolia informed Antero that the salt quality would not improve and that it was Antero's problem to remedy.

Both parties filed suit against each other, and the cases were consolidated. Antero sued Veolia for both breach of contract and fraud. The Colorado Supreme Court granted certiorari to consider whether Antero's fraud claim was barred by the economic loss rule. The court articulated the economic loss rule as follows:

> The economic loss rule developed to maintain the boundary between contract and tort law. Under the rule, a party that suffers only economic loss from the breach of an express or implied contractual duty may not assert a tort claim for that breach absent an independent duty of care under tort law. . . .
>
> To determine whether the economic loss rule applies, courts look not to the nature of the damages but to the source of the duty allegedly breached, i.e., the contract or some other source. To do so, courts consider whether (1) the relief sought in tort is the same as the contractual relief; (2) there exists a recognized common law duty of care in tort; and (3) the tort and contractual duties differ in any way. "If the parties have memorialized the applicable duty of care in their contract (i.e., if the duty is contained within or imposed under the contract), then no duty exists independent of the contract, and the economic loss rule will apply to bar a tort claim." If, however, a recognized common law tort duty exists independent of any contractual obligations, then the economic loss rule does not apply and does not bar a tort claim asserting a violation of that independent duty of care.
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> . . . .
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> . . . "Contractual duties arise just as surely from networks of interrelated contracts as from two-party agreements." *BRW, Inc. v. Dufficy & Sons, Inc.*, 99 P.3d 66, 72 (Colo. 2004).

Id. ¶¶ 30–33 (citations omitted) (alteration omitted) (quoting *Mid-Cent. Ins. Co. v. HIVE Constr., Inc.*, 2025 CO 17, ¶ 25, 567 P.3d 153; *BRW, Inc. v. Dufficy & Sons, Inc.*, 99 P.3d 66, 72 (Colo. 2004)). The court found that Veolia had fraudulently induced Antero to enter into the DBA.

Veolia argued that the DBA was part of an interlocking series of contracts and, therefore, that the economic loss rule should apply to representations Veolia made before entering the DBA. The court found this unpersuasive, concluding that "the parties signed a series of independent agreements, and the pertinent misrepresentations occurred prior to, and, on the facts presented, induced Antero to enter into, the DBA." *Id.* ¶ 45.

Additionally, the court found that even if Veolia's misrepresentations were post-contractual, it still would have found in Antero's favor. The court noted that no contractual duty would have subsumed Veolia's common law tort duty to refrain from making misrepresentations, and the economic loss rule therefore would not bar Antero's fraud claim. The contract contained no express duty to refrain from making misrepresentations, so the only contractual duty that could have precluded Antero's claim was the duty of good faith and fair dealing. However, the duty of good faith and fair dealing applies only when one party has the *discretionary* authority to determine certain terms of the contract, such as quantity, price, or time. *Id.* ¶ 50 (citing *Amoco Oil Co. v. Ervin*, 908 P.2d 493, 498 (Colo. 1995)). In this case, Veolia had no discretion to modify Clearwater's requirements, such as the salt quality or power use guarantee, without written consent. As such, Veolia had no implied contractual duty to refrain from making misrepresentations on these issues, so there was no contractual duty to subsume the common law tort duty to refrain from making misrepresentations, and the economic loss rule would not bar Antero's fraud claim. *Id.* ¶ 51.

LOUISIANA – OIL & GAS

Chelsea Young, Michael Ishee & Trinity Morale, Reporters

Louisiana Supreme Court Extends the Subsequent Purchaser Rule to Mineral Leases, but Recognizes a Separate Mineral Code Claim at Lease Termination

On May 29, 2026, the Louisiana Supreme Court issued an opinion in *Vinton Harbor & Terminal District v. Reunion Energy Co.*, 2025-00971 (La. 5/29/26), 2026 WL 1584405, confirming that Louisiana's subsequent purchaser rule, set forth in its 2011 opinion in *Eagle Pipe & Supply, Inc. v. Amerada Hess Corp.*, 2010-2267 (La. 10/25/11), 79 So. 3d 246, applies to mineral leases. As explained in *Eagle Pipe*, the subsequent purchaser rule provides that a purchaser generally has no right to recover for property damage that occurred prior to his ownership, as the right to sue is a personal right belonging to the property owner at the time of the injury. Unless that personal right is expressly assigned or subrogated, it does not pass with the property.

The court's fractured majority opinion in *Vinton Harbor* considered whether the plaintiff, Vinton Harbor and Terminal District (Vinton), had a right to seek relief from former mineral lessees for alleged damage arising from oil and gas exploration and production operations conducted by predecessors of the defendants Honeywell International (Honeywell) and Texas Pacific Oil Company (Texas Pacific). Vinton acquired surface ownership of multiple tracts of land between 1968 and 1987. Prior to Vinton's acquisition of the tracts, the prior surface owner executed a mineral lease in favor of Honeywell's predecessor; those rights were ultimately assigned to a predecessor of Texas Pacific. The mineral lease terminated in 2020, following an 87-day period in which Texas Pacific's predecessor's interest in the lease and Vinton's surface ownership overlapped. Importantly, Vinton was never a party to the mineral lease.

In 2023, Vinton filed suit against Honeywell and Texas Pacific. It asserted tort and breach of contract claims for damage allegedly caused to its property by oil and gas operations dating back to the 1930s. Honeywell and Texas Pacific filed exceptions of no right of action. They argued that, under the subsequent purchaser rule, Vinton could not sue for damage that occurred prior to its acquisition of the property. After the trial court denied the exceptions, Louisiana's Third Circuit reversed. It held that the subsequent purchaser rule barred Vinton's claims for preacquisition damage. It found, however, that Vinton would be able to recover for any damage that occurred during the 87-day period in which Vinton owned the tract and Texas Pacific's predecessor held coexisting mineral rights.

Following the Louisiana Third Circuit's ruling, Vinton applied to the Louisiana Supreme Court for supervisory writs. The central issue raised by Vinton's application was whether the subsequent purchaser rule set forth in *Eagle Pipe*, which involved a surface lease, applied in the context of mineral leases. Vinton argued that because the Louisiana Mineral Code provides that mineral rights are "real rights" (suggesting that they run with the land), *Eagle Pipe* should not control.

The *Vinton Harbor* court rejected Vinton's argument. It explained that the Mineral Code's treatment of mineral leases as real rights protects the *lessee's* ability to exercise and enforce its right to conduct operations under the lease. It does not create a claim for property damage that runs with the land. The court reasoned that, as in *Eagle Pipe*, "the asserted right [in this case] is an accrued claim for preacquisition physical property damage, which remains personal to the owner at the time of injury absent assignment." *Vinton Harbor*, 2026 WL 1584405, at *4.

The court also rejected Vinton's alternative argument that "the alleged contamination and oilfield remnants" constituted a continuing tort, finding that Vinton had not alleged an "overt, persistent, and ongoing act." *Id.* at *5. Additionally, it dismissed Vinton's contention that even if the subsequent purchaser rule bars tort and contract claims for preacquisition damage, "Mineral Code art. 11's 'reasonable regard' requirement . . . suppl[ies] an independent basis for a right of action." *Id.* The court emphasized that "*Eagle Pipe* grounded the subsequent purchaser rule in Louisiana property and obligations law" and "[n]othing in the Mineral Code alters that principle." *Id.* Therefore, the subsequent purchaser rule barred Vinton from recovering from Honeywell or Texas Pacific for any damage sustained prior to its ownership of the property.

Although the court could have ended its analysis there, it then sua sponte addressed an issue no party had briefed: whether Vinton, as a subsequent surface owner, could assert a claim under article 122 of Louisiana's Mineral Code for failure to comply with obligations imposed on mineral lessees at lease termination. Article 122 provides that a mineral lessee must perform lease obligations in good faith and "develop and operate the property leased as a reasonably prudent operator for the mutual benefit of himself and his lessor." *Id.* at *6 (quoting La. Rev. Stat. § 31:122). The court found that, unless the mineral lease states otherwise, where a mineral lessee has operated unreasonably or excessively, article 122 requires a mineral lessee to take "reasonable measures required of a prudent operator at the time of [lease] cessation or termination." *Id.* at *7. It explained that because Vinton owned the property at lease termination, Vinton had standing to pursue relief for a breach of that obligation, provided that the operations at issue were unreasonable. The court subsequently rejected rehearing applications from both sides.

Louisiana Enacts the Louisiana Energy Protection Act, Prohibiting Climate Change Suits

On June 8, 2026, Louisiana Governor Jeff Landry signed House Bill 804, the Louisiana Energy Protection Act (LEPA), 2026 La. Sess. Law Serv. Act 843, into law. The LEPA largely prohibits what are commonly referred to as "climate change suits" from being brought or proceeding in Louisiana. In such suits, plaintiffs—often state governments, local governments, or environmental advocacy groups—rely on a variety of legal theories to seek relief from energy companies for past or anticipated damage they claim has been, or will be, caused by human activity-produced climate change.

The LEPA bars a wide array of climate change-related claims. It provides, in relevant part: "No covered civil liability action for climate change damages from greenhouse gas emissions, as defined in R.S. 30:1603, shall be brought, filed, or maintained by any person against any person in any court or proceeding in this state, including any claim, cause of action, or judicial or administrative proceeding." La. Rev. Stat. § 30:1604. It defines "covered civil liability action for climate change damages from greenhouse gas emissions" to include "any claim or action [under Louisiana law] for damages, penalties, or any other form of relief whether legal or equitable or otherwise, or any cause of action for fraud, misrepresentation, deception, or failure to warn" that seeks relief "arising out of or relating to, climate change or the alleged effects of climate change for greenhouse gas emissions or any debate, public controversy, or discussion arising out of or relating to climate change, its causes, or the alleged effects of climate change from greenhouse gas emissions." *Id.* § 30:1603(2).

The LEPA does provide for certain narrow exceptions. It expressly provides that claims, actions, and proceedings (judicial and administrative) for violations of (1) Louisiana or federal statutory greenhouse gas emission limitations; (2) permits issued by Louisiana or federal agencies with jurisdiction over such emissions; and (3) federal Occupational Safety and Health Act standards, provided there is proof that the violation directly and proximately caused the relevant injury, are not prohibited. *Id.* § 30:1604.

Also exempted from the LEPA prohibition are suits and enforcement actions brought pursuant to Louisiana's State and Local Coastal Resources Management Act of 1978 (SLCRMA), La. Rev. Stat. §§ 49:214.21–.42. This is notable due to the fact that, in a number of ongoing, high-profile "coastal land loss" lawsuits, Louisiana parish and state officials sued oil and gas operator-defendants under SLCRMA, alleging that the defendants' historical oil and gas operations led to coastal erosion and marsh loss in the state. Two such cases gave rise to an April 2026 U.S. Supreme Court opinion in which a unanimous Court held that the defendants satisfied one of the requirements under 28 U.S.C. § 1442(a)(1) (the federal-officer removal statute) for removal to federal court. *Chevron USA Inc. v. Plaquemines Parish*, 146 S. Ct. 1052 (2026); *see* Vol. 43, No. 2 (2026) of this *Newsletter*.

The LEPA took immediate effect upon signing. It applies to any actions filed after June 8, 2026, regardless of when the conduct at issue occurred. Its enactment comes as the U.S. Supreme Court is set to hear oral argument in a significant climate change case, *Suncor Energy (U.S.A.) Inc. v. County Commissioners of Boulder County*, No. 25-170, this fall. There, the Court may decide whether federal law prohibits climate change suit-plaintiffs from pursuing relief under state law for injuries they allege are a result of greenhouse gas emissions—specifically, where those emissions emanate beyond a state's borders.

NEBRASKA – OIL & GAS

Hannes D. Zetzsche, Reporter

Nebraska Legislature Regulates Data Centers, Energy Storage Resources, and Other Large Energy Loads Affecting Power Generation

The Nebraska legislature enacted two energy bills during its 2026 session that will impact power generation from all different sources. Both bills took effect on July 18, 2026. *See* L.B. 1010, 109th Neb. Leg., 2d Sess. (2026); L.B. 1261, 109th Neb. Leg., 2d Sess. (2026).

First, L.B. 1261 protects privately owned electric generation facilities constructed to serve on-site industrial customers with new electric loads exceeding 1,000 megawatts from acquisition by eminent domain. The main facilities contemplated under this bill are on-site natural gas generation facilities. Neb. Rev. Stat. § 70-670(5).

The bill bars a consumer-owned electric supplier from condemning such a facility where the facility (1) co-locates with or sits adjacent to the industrial customer, (2) maintains an electrically equivalent point of grid interconnection to that customer, and (3) has secured Nebraska Power Review Board approval. *Id.*

The generation facility owner and the consumer-owned utility must execute a long-term power purchase agreement, lease, joint venture, or other commercial contract. *Id.* § 70-670(5)(a)(ii). Unless the utility consents otherwise, the generation facility may serve only the on-site industrial customer. *Id.* § 70-670(5)(a)(iv). The industrial customer must pay all costs, fees, and electric system upgrade costs the project causes. *Id.* § 70-670(5)(a)(iii). The bar applies only to contracts the parties execute on or before December 31, 2031. *Id.* § 70-670(5)(c).

Second, L.B. 1010 directs utilities to adopt interconnection standards for "large-load customers." The bill defines a large-load customer as a retail customer that requests interconnection exceeding 20 megawatts at a single site. *Id.* § 70-2202(1).

Under these standards, large-load customers must provide the utility:

- a disclosure of any similar service requests that could materially change, delay, or replace the interconnection request;
- evidence of any on-site backup generation;
- a demonstration of site control;
- financial commitments for necessary transmission and generation infrastructure; and
- a study fee of at least $50,000 or $1,000 per megawatt, whichever is greater; the utility must complete its initial studies within one year after receiving the fee.

Id. § 70-2203(1).

Nebraska law generally requires utilities to charge reasonable, nondiscriminatory electric rates. *Id.* § 70-655; *see McGinley v. Wheat Belt P.P. Dist.*, 332 N.W.2d 915 (Neb. 1983). However, L.B. 1010 authorizes utilities to establish or negotiate large-load-specific rates, charges, and operating standards that allocate system costs to large-load customers and mitigate operational, resource adequacy, and financial risks to other ratepayers. Neb. Rev. Stat. § 70-2203(2). Utilities also must develop procedures for serving large-load customers and curtailing their power supply during emergency conditions. *Id.* § 70-2204.

Third, L.B. 1010 codifies a permitting standard for energy storage resources (ESRs). An ESR is a facility that draws electric energy from the grid or a related generation source and stores that energy for later injection back into the grid. *Id.* § 70-1001.01(9). The bill separates ESRs into two categories: "associated" ESRs and "standalone" ESRs.

An associated ESR stores energy generated by a co-located privately developed renewable energy generation facility. *Id.* § 70-1001.01(1). Operators may pair an associated ESR with such a generation facility without obtaining Power Review Board approval, provided the ESR limits its output to the generation facility's nameplate capacity. The generation facility and associated ESR may then operate together under the wind or solar farm's existing certification. *Id.* § 70-1014.02(2). No consumer-owned electric supplier may condemn an associated ESR. *Id.* § 70-1014.02(5).

A standalone ESR, by contrast, operates independently of a privately developed renewable energy generation facility. *See id.* § 70-1001.01(1). The developer must obtain Nebraska Power Review Board approval before construction. The Board grants this discretionary approval only after conducting an administrative law proceeding. *See id.* § 70-1014.

L.B. 1010 imposes three additional conditions on privately owned standalone ESRs. Before applying to the Board, the developer must:

- secure an agreement to purchase all of the ESR's electric energy and electric capacity with a Nebraska public power entity;
- obtain written consent from any utility in whose service territory the ESR will locate or with whose transmission lines the ESR will interconnect; and
- negotiate and execute a joint transmission development agreement with the utility to whose transmission lines the ESR will interconnect.

Id. § 70-1012(5).

The Board may not approve a standalone ESR unless it finds that the project "will serve the public convenience and necessity, and . . . most economically and feasibly supply the electric service resulting from the proposed construction or acquisition without unnecessary duplication of facilities or operations." *Id.* § 70-1014(1)(a). Once the Board approves a standalone ESR, no electric supplier may condemn the ESR. *Id.* § 70-1012(8).

These bills took effect on July 18, 2026. As of the time of this report, no large-load ESRs or large-load customers have commenced operation under these bills. Time will tell what impact the bills have on development.

PACIFIC NORTHWEST – MINING/OIL & GAS

Andrew A. Irvine & Wade C. Foster, Reporters

DOGAMI Fee Legislation Took Effect January 1, 2026, in Oregon

Oregon Senate Bill 836, approved July 24, 2025, and enacted as chapter 601 of the 2025 Oregon Laws, took effect on January 1, 2026, and increases fees charged by the Oregon Department of Geology and Mineral Industries (DOGAMI). The measure affects a broad range of DOGAMI-administered programs, including mineral exploration, surface mining, oil and gas wells, prospect wells, seismic or information holes, and geothermal wells. The legislation is best understood as a permitting capacity and program funding measure rather than a change to the substantive standards governing mineral development or reclamation.

The practical effect for exploration and mining operators is the need for immediate budgeting and transactional diligence. Among other changes, the legislation increases mineral-exploration permit renewal fees; surface mining operating permit application and renewal fees; reclamation plan change and special inspection fees; and various oil and gas, prospect well, and geothermal well permit fees. For example, the legislation increases the oil and gas well drilling permit application fee from $2,000 to $5,000, the maximum surface mining operating permit application fee from $2,000 to $6,500, certain surface mining operating permit renewal fees to $2,300, the reclamation plan change cost cap from $2,000 to $4,000, and the special inspection fee cap from $2,000 to $4,000.

The measure grew out of a documented agency-capacity issue. The Legislative Fiscal Office stated that DOGAMI's Mineral Land Regulation and Reclamation program was not meeting regulatory timelines for permit processing or compliance and safety inspections, and that the fee adjustments were intended to align revenues with program costs and support additional staffing. Fiscal Impact of Proposed Legislation, S.B. 836-4, 83d Or. Leg. Assemb., Reg. Sess. (May 26, 2025). For Oregon projects, the change should be flagged in early-stage exploration budgets, surface mine operating plans, permit modification planning, and asset transactions involving DOGAMI-regulated permits.

Mining Permit Streamlining Proposal Did Not Become Law

Oregon also considered, but did not enact, House Bill 2777 (HB 2777), 83d Or. Leg. Assemb., Reg. Sess. (2025), a targeted mining permitting bill. As summarized by legislative staff, the bill would have exempted certain sample material wells constructed by licensed water well constructors from onshore exploration permit requirements, limited the Oregon Department of Geology and Mineral Industries' (DOGAMI) ability to impose additional conditions on transfers of operating permits for uncompleted surface mining operations, authorized a permit transfer fee of up to $250, and restricted DOGAMI or other permitting agencies from requiring a land use compatibility statement for activities already authorized by a local jurisdiction. Staff Measure Summary, HB 2777, 83d Or. Leg. Assemb., Reg. Sess. (Mar. 26, 2025).

Because HB 2777 remained in committee upon adjournment, it did not amend Oregon law. It is nevertheless worth noting because it reflects continued legislative interest in reducing duplicative land use and mining permit review and clarifying DOGAMI's authority over permit transfers. If similar legislation is reintroduced, it could materially affect exploration well planning, permit transfer diligence, and the sequencing of local land use approvals and DOGAMI permitting.

Surface Mine Reclamation Permit Fees Increased in Washington

Washington enacted Senate Bill 5319, ch. 326, 2025 Wash. Sess. Laws, effective July 27, 2025, amending Wash. Rev. Code § 78.44.085 to increase surface mine reclamation permit fees. The legislation applies to Washington's surface mine reclamation program, under which the Department of Natural Resources (DNR) regulates reclamation of lands and waters affected by surface mining activities.

As enacted, the bill revised the application and revision fee structure by requiring a $4,500 nonrefundable application fee for a revision of an existing reclamation permit or reclamation plan, an expansion of a permitted surface mine, a new reclamation permit, or a combination of existing public or private surface mine reclamation permits. It also increased the annual fee for most public and private permit holders from $2,000 to $3,500 and established a $2,500 annual fee for public permit holders for mines used exclusively for public works projects, while retaining a $1,000 cap for certain county public works mines with less than seven acres of disturbed area per mine. S.B. 5319, ch. 326, § 1, 2025 Wash. Sess. Laws (codified at Wash. Rev. Code § 78.44.085).

The legislation also imposes an administrative timing requirement. Within 60 days after receiving an application for a new or expanded permit or a revision to an existing reclamation permit or reclamation plan, DNR must advise the applicant of any information necessary to successfully complete the application. *Id.* For operators, this change affects both annual compliance costs and the process for revising reclamation plans. It should be considered in budgeting, permit renewal calendars, reclamation plan amendments, and acquisition diligence for Washington aggregate and surface mine assets.

Ninth Circuit Allows CERCLA Lost-Use Natural Resource Damages with Cultural Dimension

In *Confederated Tribes of the Colville Reservation v. Teck Cominco Metals Ltd.*, 153 F.4th 947 (9th Cir. 2025), *petition for cert. docketed*, No. 26-130 (July 29, 2026), the U.S. Court of Appeals for the Ninth Circuit reversed the district court's grant of summary judgment for Teck Cominco Metals, Ltd. (Teck) in Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) natural resource damages litigation involving contamination of the Upper Columbia River in Washington from Teck's lead-zinc smelter in Trail, British Columbia. The Confederated Tribes of the Colville Reservation sought damages for their members' interim lost use of injured natural resources under CERCLA § 107(a)(4)(C), 42 U.S.C. § 9607(a)(4)(C).

The district court had characterized the claimed damages as damages for injured "cultural resources" rather than natural resources and held that damages with a cultural component were not cognizable under CERCLA. The Ninth Circuit rejected that framing. It held that CERCLA natural resource damages may include interim lost-use damages for injured natural resources even when the lost uses have a cultural dimension, so long as the damages are tied to injury to natural resources within the statute.

The decision matters for mining and mineral processing operations because it may expand the practical scope of natural resource damages exposure where releases injure fish, water, sediments, or other natural resources used by tribes or other trustees in culturally significant ways. It is particularly relevant to transboundary mining and smelting operations, CERCLA allocation strategy, expert valuation of lost-use damages, and settlement evaluation in cases involving tribal natural resource trustees. The opinion does not create CERCLA liability for injury to cultural resources as such; rather, it recognizes that lost uses of injured natural resources are not excluded merely because those uses have cultural significance.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart, Sean M. McGovern, Gina F. Buchman & Matthew C. Wood, Reporters

PADEP Provides an Update on the OOOOc State Plan

The Pennsylvania Department of Environmental Protection (PADEP) provided an update on its OOOOc Final State Plan at the Air Quality Technical Advisory Committee Meeting on August 6, 2026.

As detailed in previous editions of this *Newsletter*, on March 8, 2024, the U.S. Environmental Protection Agency (EPA) finalized its rule targeting methane emissions from the oil and natural gas sector (the Methane Rule), which established New Source Performance Standards (NSPS) for facilities built, modified, or reconstructed after December 6, 2022 (OOOOb), as well as Emissions Guidelines (EG) (or model rule) for states to follow in designing and executing state plans for existing sources (OOOOc). 89 Fed. Reg. 16,820 (Mar. 8, 2024) (to be codified at 40 C.F.R. pt. 60); *see* Vol. 42, No. 3 (2025) and Vol. 41, No. 4 (2024) of this *Newsletter*. The Methane Rule applies to oil and gas facilities involved in production and processing (including equipment and processes at well sites, storage tank batteries, gathering and boosting compressor stations, and natural gas processing plants) and natural gas transmission and storage (including compressor stations and storage tank batteries). The Methane Rule requires frequent monitoring and repair of methane leaks at well sites, centralized production facilities, and compressor stations using established inspection technologies or, at an operator's selection, novel advanced detection technologies. OOOOb applies to affected facilities that begin construction, reconstruction, or modification after December 6, 2022, while OOOOc (as implemented by state programs) will apply to sources existing as of that date. The main differences between OOOOb and OOOOc are the timeframes for compliance and the additional requirements for new wells, particularly relating to flaring and well completions.

PADEP is required to submit a State Plan based on the OOOOc model rule. The original deadline under the Methane Rule to submit a state plan was March 8, 2026, two years after the publication of the final rule. This deadline was, however, extended until January 22, 2027, by an interim final rule published by EPA on July 31, 2025. 90 Fed. Reg. 35,966 (July 31, 2025).

The State Plan must include an inventory of designated facilities and their emissions, compliance schedules for each designated facility or logical grouping, standards of performance (which must be at least as stringent as the model rule except as determined when examining remaining useful life and other factors), enforceability mechanisms, provisions for progress reports to EPA, and a demonstration of the Commonwealth's authority to promulgate the plan. The State Plan must also document meaningful engagement, which includes input from PADEP advisory bodies, environmental justice communities, stakeholder outreach and discussion, and public hearings.

PADEP presented a draft State Plan in late 2024 which proposed a General Permit approach for OOOOc enforceability, which would be proposed and developed after the public comment period, which began on May 31, 2025, and ended on July 30, 2025. PADEP received more than 10,000 comments on the proposal. A summary of the comments can be found in PADEP's presentation of the Air Quality Technical Advisory Committee. *See* PowerPoint Presentation, PADEP, "40 CFR Part 60 Subpart OOOOc Final State Plan" (Aug. 2026).

After the close of the comment period, however, the Pennsylvania legislature passed Act 45 of 2025, which appended section 6.1(g) of the Air Pollution Control Act, 35 Pa. Stat. § 4006.1(g). This new provision mandates that PADEP review general permit applications within 30 days. As a result, PADEP had determined that developing a General Permit as the enforcement mechanism for the OOOOc State Plan is untenable. PADEP will instead propose a rulemaking process under the Air Pollution Control Act.

PADEP plans to submit a State Plan to EPA by January 22, 2027, for conditional approval and will also conduct an information request for equipment inventories from conventional well site and centralized production facilities and review this information to determine performance standards. PADEP will then draft and provide opportunity for public engagement on the proposed rule and submit it to the Environmental Quality Board. As detailed in the most recent regulatory agenda published in the *Pennsylvania Bulletin* on July 25, 2026, PADEP plans to promulgate separate rules for conventional and unconventional oil and natural gas sites in the second quarter of 2027. 56 Pa. Bull. 4485 (July 25, 2026). Further updates will be provided in subsequent editions of this *Newsletter* as the rulemaking progresses.

PADEP Publishes Pennsylvania's Proposed 2026 Annual Ambient Air Monitoring Network Plan

On June 20, 2026, the Pennsylvania Department of Environmental Protection (PADEP) published a notice in the *Pennsylvania Bulletin* of the availability of the 2026 Annual Ambient Air Monitoring Network Plan (Plan) for public comment. 56 Pa. Bull. 3692 (June 20, 2026). Under the Clean Air Act, states and the federal government work together in regulating air pollution.

To monitor compliance with the National Ambient Air Quality Standards (NAAQS), the U.S. Environmental Protection Agency (EPA) requires states to create a network of ambient air monitors to measure air quality. Pennsylvania's Plan includes 63 stations in 39 counties and prioritizes new and expanded monitoring near industrial sources, including ozone, hydrogen sulfide, and PM2.5 monitoring sites. Each monitor has a statement of purpose and evidence that the monitor's location and operation meets federal requirements pursuant to the national ambient air monitoring requirements codified at 40 C.F.R. pts. 53 and 58.

The Plan has been updated to address changes to Pennsylvania's ambient air monitoring network and to identify changes anticipated to occur in the remainder of 2026 and in 2027. For example, PADEP plans to install a temporary Special Purpose Monitor at Fort McIntosh due to the proximity to major nitrogen dioxide emitting sources, including the Shell Pennsylvania Petrochemicals Complex in Beaver County.

The public comment period closed on July 20, 2026. After considering and responding to comments, PADEP will submit the final Plan to the regional EPA administrator for review and inclusion in Pennsylvania's state implementation plan. Upon review, EPA will publish a proposed rule in the *Federal Register* approving or disapproving Pennsylvania's final Plan.

Pennsylvania's Natural Gas Act 13 Impact Fee Revenue Rose 48% in 2025

On June 9, 2026, Pennsylvania's Independent Fiscal Office (IFO) reported impact fee revenues of $243.9 million for calendar year 2025, a 48% increase from the prior year. *See* IFO, "Impact Fee Update and Outlook" (June 2026). The increase was driven by a higher New York Mercantile Exchange-linked fee schedule and 442 new unconventional wells spud in 2025; an increase of 138 wells from the prior year. *Id.* Act 13 subjects new or "Year One" wells to the highest impact fee, making new wells an important measure for municipal governments.

The average annual NYMEX price was $3.43, triggering higher fees for most unconventional wells. In calendar year 2025 the average fee per well was $19,504, compared to $13,560 in 2024. Distributions for calendar year 2025 are allocated as follows:

- $134 million to counties, municipalities, and the Housing Affordability and Rehabilitation Enhancement Fund;
- $89.4 million to the Marcellus Legacy Fund;
- $10.5 million to commonwealth agencies; and
- $10 million to conservation districts and the State Conservation Commission.

Municipalities in Washington, Susquehanna, and Bradford counties received the majority of disbursements to local governments. *See* Pa. Pub. Util. Comm'n, "Act 13—Disbursements and Impact Fees," https://www.act13-reporting.puc.pa.gov/Modules/PublicReporting/Overview.aspx.

Although fees collected in 2025 represent a significant increase year-over-year, the total falls short of the record $278.88 million collected in 2022. *Id.* Between 2022 and 2023, the price of natural gas averaged $6.45 per British Thermal Unit, but prices declined in 2023 and remained lower through 2024. If the NYMEX average remains between $3.00 and $4.99 during calendar year 2026, the fee schedule will not change. With flat new-well activity and an assumed NYMEX average of $3.70, the IFO projects revenues of $248 million for 2026, an increase of about 2% over 2025. The Pennsylvania Public Utility Commission has submitted this year's distribution data to the Pennsylvania Treasury, which was expected to begin issuing payments in early July 2026.

PADEP Announces 400 Orphan and Abandoned Wells Plugged Under Shapiro Administration

On June 10, 2026, the Pennsylvania Department of Environmental Protection (PADEP) announced that 400 orphan and abandoned wells have been plugged since Governor Shapiro took office, with more wells plugged in the last three years than in the prior 11 years combined. *See* News Release, PADEP, "Plugging More Wells: Shapiro Administration Marks 400th Orphan and Abandoned Well Plugged, Continuing Historic Progress in Pennsylvania to Protect Public Health, Create Jobs, and Reduce Methane Emissions" (June 10, 2026). The four-hundredth well, located in North Fayette Township, Washington County, was plugged under an emergency contract after active methane leakage was identified in a residential neighborhood less than one mile from West Allegheny Middle School and High School.

Since the first commercial oil well was drilled in 1859 in Titusville, Pennsylvania, the conventional and unconventional oil and gas industries have drilled hundreds of thousands of wells across the commonwealth. Generally, Pennsylvania's Oil & Gas Act requires a well owner to plug a well upon abandonment, i.e., if it has not been used to produce, extract, or inject any gas, petroleum, or other liquid within the preceding 12 months; if equipment necessary for production, extraction, or injection has been removed; or it is considered dry and not equipped for production within 60 days after drilling, redrilling, or deepening. 58 Pa. Cons. Stat. § 3203. An "orphan well" is defined as "[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.*

The Oil & Gas Act authorizes PADEP to plug orphan and abandoned wells and to date, PADEP has identified more than 27,000 such wells statewide, prioritizing plugging wells that pose the greatest risks to health, safety, and the environment. PADEP is also addressing the abandoned or orphaned wells surrounding high-priority active wells to drive efficiency and reduce future threats. Governor Shapiro has directed PADEP to leverage all available federal resources to fund plugging abandoned and orphaned oil and gas wells, including an initial $25 million grant in 2022 from the U.S. Department of the Interior under the Infrastructure Investment and Jobs Act, followed by a $76.4 million DOI Phase 1 Formula Grant in 2024, a $114.6 million DOI Phase 2 Formula Grant in 2026, and the potential for additional funding through a DOI Phase 3 Formula Grant in the future. More information about PADEP's Well Plugging Program is available at https://www.pa.gov/agencies/dep/programs-and-services/oil-and-gas/legacy-wells/well-plugging-program.

In a related update, in April 2026 PADEP issued a new information sheet and surety bond agreement for oil and gas wells for establishing an initial, replacement, or additional surety bond covering a permittee's well plugging-related liability. PADEP provided no notice or explanation for the change. *See* https://greenport.pa.gov/elibrary/ViewFolderDocuments?FolderID=2158320.

PADEP Pilot Program Awarded $14 Million Federal Grant to Test Enhanced Geothermal Systems Model in Natural Gas Wells

On April 14, 2026, the U.S. Department of Energy (DOE) announced that a Pennsylvania Department of Environmental Protection (PADEP) pilot program would receive $14 million to evaluate the potential for cost-effective electricity generation via enhanced geothermal systems (EGS). Among the DOE-backed pilot programs, PADEP's is the only one to "leverage the significant thermal resources in the Appalachian Utica Shale to assess the efficacy and scalability of EGS in the eastern United States." Press Release, DOE, "U.S. Department of Energy Announces $14 Million for Enhanced Geothermal Systems Demonstration Project in Pennsylvania" (Apr. 14, 2026).

Geothermal energy utilizes the earth's interior heat to create energy, is considered renewable, and produces negligible amounts of pollutants or carbon emissions. Specifically, PADEP will use this award to fund the conversion of a horizontal Utica Shale natural gas well to geothermal service and field testing needed to design and stimulate an EGS reservoir. *Id.* Testing will include engineering to determine well orientation and placement, and trials of fracture-creation techniques to enable fluid flow through hot rock for power generation. PADEP has indicated that because the project leverages existing oil and gas facilities, no additional land is required for the renewable generation facilities.

The PADEP pilot program will collect data on fracture performance, reservoir connectivity, fluid flow characteristics, well configuration effectiveness, and overall power production potential to determine whether a replicable EGS model can be scaled in similar eastern U.S. geologies. If successful, the project is intended to provide a replicable model to expand EGS deployment to other sites around the country and to expand knowledge and data about how EGS reservoirs function across geologies and subsurface conditions. *Id.*

Other projects include pilots by Fervo Energy (producing power from three wells at a site within the Milford Renewable Energy Corridor in Utah with no existing commercial geothermal power production) and Mazama Energy (super-hot EGS at temperatures exceeding 375°C on the western side of Newberry Volcano in Oregon). *See* DOE Geothermal Technologies Office, "EGS Pilot Demonstrations," https://www.energy.gov/hgeo/geothermal/egs-pilot-demonstrations.

TEXAS – OIL & GAS

William B. Burford, Reporter

Texas Court Held to Have Jurisdiction of Dispute over West Virginia Properties

In 2015 Texas residents Robert Scott Bauer and Brad Ashburn agreed with Enerquest Oil & Gas to form a new company, Braxton Minerals III, LLC (BM3), to purchase mineral rights in Appalachia. In one particular series of transactions, mineral interests in land in West Virginia were acquired in the name of a different entity of Bauer's and Ashburn's, which then received royalty payments on production from the properties. When Bauer refused BM3's request to correct the deeds to vest title in BM3, BM3 filed suit in Tarrant County, Texas, and was granted summary judgment for (1) specific performance of the parties' agreements, (2) reformation of the deeds in question, (3) a declaration affirming BM3's ownership of the disputed royalties, and (4) an injunction prohibiting the defendants from transferring the properties or the royalty payments. The court of appeals reversed the trial court's summary judgment and dismissed the case, 689 S.W.3d 633 (Tex. App.—Fort Worth 2024), holding that the Texas court lacked jurisdiction where the gist or gravamen of the claim involved adjudication of title to foreign real property interests. In *Braxton Minerals III, LLC v. Bauer*, 735 S.W.3d 688 (Tex. 2026), the Texas Supreme Court reversed the court of appeals.

While courts lack jurisdiction over in rem suits about foreign property, the court pointed out, there is generally no jurisdictional impediment to in personam suits about foreign property, assuming the court has jurisdiction over the parties. When a plaintiff requests a judgment to enforce a defendant's legal obligation to convey property, rather than a judgment that will vest title in the plaintiff of the judgment's own force, the suit is in personam, it explained, and the out-of-state location of the property is no bar to jurisdiction. The court expressly disapproved of lower-court decisions that Texas courts lack jurisdiction if the "gist" or "gravamen" of the claim involves adjudication of title to foreign real estate. The proper focus is on the nature of the court's *judgment*, it said, not on the legal questions the court confronts on the way to the judgment.

Turning to the judgment at issue in this case, the court noted that specific performance of a contract for lands lying elsewhere is the quintessential example of in personam relief available in a court of equity even though lands outside the court's jurisdiction may be affected. The same is true of reformation, it went on, which is equitable relief effected through coercion of the defendant, such as by directing a deed to be executed or canceled by a party. The district court, the court remarked, understood BM3's request for reformation that way, ordering the defendants to reform the deeds rather than doing so itself.

The court finally held that the declaratory judgment concerning BM3's disputed royalties was also within the court's power. Because such a judgment does not, by statute, prejudice the rights of a non-party, according to the court, a declaration such as this is by definition an in personam judgment binding only on the parties, not an adjudication of title in an absolute or definitive sense, as against the world. The district court's declaration that BM3 was the rightful owner of the disputed royalties pursuant to the parties' agreement, in the court's analysis, sought to require the defendants to convey property as they allegedly promised to do, a form of in personam relief even when the subject is foreign land.

In summary, nothing about the district court's judgment purported, by the mere force of its decree, to annul a deed or establish title. It only validly enforced a contractual obligation to convey the land.

Agreement's Payment Obligation Not Excused by Funding Failure

The court in *Border to Border Exploration, LLC v. BP America Production Co.*, No. 03-24-00352-CV, 2026 WL 1353574 (Tex. App.—Austin May 15, 2026, no pet.) (mem. op.), enforced a 2013 development agreement between BP America Production Co. (BP) and Border to Border Exploration, LLC and BBX Operating, LLC (collectively, BBX), concerning 6,513.11 net mineral acres owned by BP in land in Jasper County, Texas.

Under the agreement BP granted BBX the right to conduct seismic studies on the land and to lease any of it for drilling. BP would have the right to participate in any wells as a working interest owner and was to have a credit toward its drilling costs in the amount of $200 per net mineral acre for any land included in a BBX seismic study and another $400 per net mineral acre for any acreage leased. Those amounts would, according to the agreement, constitute a "Drilling Account" to be maintained by BBX, which BP could request to be disbursed to it on 30 days' notice and the unused portion of which would be, in any event, disbursed to BP on the earlier of three years after the agreement's effective date or the agreement's termination.

BBX completed its seismic study over all of the BP acreage, generating a credit to BP for its drilling costs in the amount of $1,302,622 ($200 multiplied by BP's 6,513.11 net acres). It never leased any of the BP acreage, though, and never proposed a well. After an extended drilling deadline expired in 2016, BP notified BBX that the agreement had terminated and demanded disbursement of its drilling credit. BBX lacked the funds to pay because the amount had been spent elsewhere, and BP filed suit. After a bench trial, the district court rendered judgment for BP, and the court of appeals affirmed.

BBX's principal argument on appeal was that it had not breached its contract with BP because there were no funds in BP's drilling account to disburse. It relied in particular on a provision of the parties' development agreement that made it "subject to" two other agreements between BBX and others who would be called upon to fund its operations. BBX's receipt of funds from the other parties, it contended, was a condition precedent to the funds' disbursement to BP. Because BBX had been unable to obtain payments from its participants for the BP credit, it maintained, it could not pay and was not obligated to do so.

Rejecting BBX's position, the court of appeals pointed out that the agreement plainly provided that on its termination, BBX *shall* disburse to BP any unused drilling credit. BBX's third-party agreements did not modify its contractual responsibility for disbursing BP's credits—at most, the court remarked, they merely provided BBX a method to raise money. There was simply no language in the BP agreement making the disbursement obligation conditional upon BBX's receiving payments under its other agreements.

Conveyance of 1/32 of Minerals, Stripped of Executive Rights and Rights to Bonuses and Rentals, Held to Entitle Grantee to 1/32 of Royalty Regardless of Historical Treatment as 1/32 of Production

The court in *B.H.C.H. Mineral, Ltd. v. Needmore Minerals, LLP*, No. 04-24-00382-CV, 2026 WL 1430702 (Tex. App.—San Antonio May 20, 2026, no pet. h.), construed a 1937 deed from Esperanza Livestock & Land Company (Esperanza) to John F. Sinclair conveying a 23,513.3-acre ranch in Webb County, Texas. The deed reserved to Esperanza an "undivided One-Thirty-second (1/32) of all oil, gas and other minerals on, in and under said land," further providing that the grantee would have the right to execute oil, gas, and other mineral leases without the grantor's joining, that the grantor would not share in any lease bonuses or delay rentals, and that any lease must retain a royalty of at least 1/8. On competing motions for summary judgment, the trial court granted that of Needmore and others, successors to the grantee's interest, declaring that the reservation consisted of a "non-executive mineral interest" entitling the grantor to 1/32 of the current lease royalty and not, as the owners of the reserved interest (referred to by the court of appeals as "Esperanza") argued, 1/32 of total production. The court of appeals affirmed.

Relying largely on *French v. Chevron U.S.A. Inc.*, 896 S.W.2d 795 (Tex. 1995), and *Altman v. Blake*, 712 S.W.2d 117 (Tex. 1986), the court noted that the pattern—reservation of a mineral interest followed by carve-outs of the executive, bonus, and delay-rental rights—matched the structure the supreme court has treated as a nonexecutive mineral interest rather than a pure royalty interest. Further, the court observed, the deed's requirement that any lease must retain at least a 1/8 royalty confirmed that the grantor's share of production was tied to the lessor's royalty, not to gross production. Thus, it concluded, the deed reserved a 1/32 non-executive mineral interest with a "floating" royalty interest.

The court's conclusion regarding the deed's proper construction is unremarkable, but its treatment of Esperanza's other principal argument, based on the presumed-grant doctrine, is curious. For many years the Esperanza owners had been paid by oil and gas operators for a fixed 1/32 of oil and gas production. Relying on *Van Dyke v. Navigator Group*, 668 S.W.3d 353 (Tex. 2023), and *Clifton v. Johnson*, 733 S.W.3d 16 (Tex. 2026), Esperanza asserted that the long-standing treatment of the reserved interest as a fixed 1/32 nonparticipating royalty interest established that as the interest for which it should continue to be paid. The court disagreed.

The presumed-grant doctrine, the court began, requires proof of (1) a long-asserted and open claim, adverse to that of the apparent owner; (2) non-claim by the apparent owner; and (3) acquiescence by the apparent owner in the adverse claim. Esperanza's attempt to apply the doctrine to a royalty interest was novel, according to the court, and it found no Texas decision presuming a grant of a royalty interest. The doctrine fits poorly, it believed, with passive receipt of royalty, as opposed to corporeal interests in land, where physical possession can signal a claim of right. No Texas court, the court declared, has extended presumed grant to change the character of a royalty interest or to transform a mineral interest or a floating royalty interest into a fixed royalty, and the doctrine's foundations offered little support for doing so in this case. In any event, the court found no evidence of the required long-asserted and open claim adverse to the apparent owner, notwithstanding division orders reflecting a fixed 1/32 share of production and testimony, correspondence, and documents by owners of the grantee's interest acknowledging Esperanza's fixed 1/32 interest in production. That evidence showed how operators and the burdened owners described and accounted for the Esperanza interest, but did not, in the court's view, show that the Esperanza owners themselves ever openly asserted a hostile claim to a fixed royalty interest against the apparent owner.

The court's practically flat refusal to apply the presumed-grant doctrine to a royalty interest seems questionable, and a dissenting justice would have held that the doctrine established Esperanza's case. No authority limits the application of the doctrine to non-possessory interests, the dissent pointed out, and in fact the Texas Supreme Court's *Clifton* opinion, cited by the majority without any effort to distinguish it, extensively discussed, albeit as dicta, how the elements of the presumed-grant doctrine appeared to have been met concerning the non-possessory royalty interest at issue in that case. The dissent also criticized the majority's cursory holding that the respective owners' treatment of the Esperanza interest, evidenced by five decades of division orders, royalty payments, and conveyances recognizing it as a fixed 1/32 of production and apparently unrefuted, did not meet the requirements of the presumed-grant doctrine that the court cited.

Lessee Has No Common-Law Duty Not to Wash Out Overriding Royalty Interests

Craddick v. Cimarex Energy Co., No. 08-24-00010-CV, 2026 WL 1500933 (Tex. App.—El Paso May 28, 2026, no pet.) (mem. op.), involved a 1943 oil and gas lease covering 1,440 acres in Reeves County, Texas. In assignments of the lease made in 1990 and 2014, respectively, Thomas Craddick and George Staley had reserved overriding royalty interests aggregating 11.5625% of the oil and gas produced under the lease. By 2017, BPX Properties (N.A.) LP (BPX) had succeeded to the working interest under the lease, and Cimarex Energy Co. (Cimarex) held the mineral estate of the land subject to the lease.

Amid uncertainty, apparently serious, whether the lease was being maintained by paying production, Cimarex and BPX began negotiating a transaction to enable Cimarex to develop the acreage covered by the lease. Instead of assigning the 1943 lease to Cimarex, BPX released it, whereupon Cimarex proceeded to develop the land unburdened by the Craddick and Staley overriding royalty interests or any other third-party interests except for a small nonparticipating royalty interest. Craddick and Staley's surviving wife sued BPX for breach of contract and bad-faith washout of their overriding royalty interests and Cimarex for conspiracy. The trial court granted summary judgment to BPX and Cimarex, and the court of appeals affirmed.

Craddick and Staley contended that a common-law duty of good faith and fair dealing exists in oil and gas leasing, limiting the power of parties to destroy the property interests of overriding royalty owners through a washout transaction. They pointed to *KCM Financial LLC v. Bradshaw*, 457 S.W.3d 70 (Tex. 2015), in which the Texas Supreme Court recognized that a mineral owner, in leasing its interest, has a fiduciary-like duty of utmost good faith and fair dealing to the owner of a nonparticipating royalty interest and so may not gain an advantage from leasing that is not shared with the royalty owner. The court was not persuaded that such a duty should be extended to bad-faith washout claims.

Texas law generally does not impose a broad duty of good faith between contracting parties, the court pointed out. Cases such as *Barrow-Shaver Resources Co. v. Carrizo Oil & Gas, Inc.*, 590 S.W.3d 471 (Tex. 2019), and *Sunac Petroleum Corp. v. Parkes*, 416 S.W.2d 798 (Tex. 1967), it believed, suggest that any duty owed to an overriding royalty holder would require evidence of a relationship between the parties beyond an arm's length sale of an oil and gas lease. Neither Craddick nor Staley offered any evidence as to whether overriding royalty owners, as opposed to owners of nonparticipating royalty interests, are more or less susceptible to inherently unequal bargaining power, nor did the record address what social and economic effects on the oil and gas industry would result from recognizing a duty to overriding royalty owners.

The court recognized that the Texas legislature had enacted a statute, introduced by Craddick himself as a state representative, effective in 2023, creating a cause of action for bad-faith washout of an overriding royalty interest. The parties agreed that Craddick and Staley could not rely on the new statute, which applies only to transactions occurring after its effective date, and the statute did not itself establish a basis to recognize a common-law duty of good faith, the court observed.

The court concluded by rejecting Craddick's and Staley's claim that BPX violated a provision of the lease that if the lessee desired cancellation of the lease it must "in good faith" deliver a release. Contrary to the overriding royalty owners' contention that BPX was obligated not to release the lease except in good faith, the court held that because the clause neither authorized nor limited the lessee's ability to surrender the lease, it merely set forth a recordkeeping obligation.

Title Not Established by Assignment Made Subject to Unrecorded Agreement of Unknown Content

Brown v. Endeavor Energy Resources, L.P., No. 11-24-00320-CV, 2026 WL 1593646 (Tex. App.—Eastland June 4, 2026, no pet. h.) (mem. op.), concerned an overriding royalty interest in two oil and gas leases assigned by Randy A. Brown to Atlantic Richfield Company (Arco) in a November 30, 1998, assignment. The instrument assigned the overriding royalty interest, described the leases, and stated that the assignment was "made subject to the terms and conditions of that certain unrecorded Letter Agreement dated November 13, 1998 between Assignor and Assignee."

After Randy Brown died in 2018, Endeavor Energy Resources, L.P. (Endeavor), evidently the operator of a well or wells producing from land covered by the leases, sent division orders to his sons, Ryan Alan Brown and Hunter Brent Brown, who had inherited their father's holdings, identifying the Browns as the owners of the overriding royalty interest. Those contained the customary clause that the payee agrees to refund any amount attributable to the described interest that the payee does not own. Between then and 2022 Endeavor paid the Browns more than $2.3 million attributable to the overriding royalty interest.

Endeavor eventually discovered the Arco assignment and claimed that, as Arco's successor-in-interest, it owned the overriding royalty interest. The Browns declined Endeavor's request that they refund the amounts they had been paid, and Endeavor sued them for breach of the division orders by failing to refund payments on the overriding royalty interest that they did not own. The trial court granted summary judgment to Endeavor on the basis of the Arco assignment, awarding it the amount of the payments to the Browns as well as attorney's fees. The court of appeals reversed, holding that Endeavor had not established as a matter of law, without producing the letter agreement referred to in the assignment, that Randy Brown had effectively assigned the overriding royalty interest to Arco.

When interpreting the assignment, said the court, it must consider all of its provisions in their entirety, including those incorporated by reference; therefore, the Arco assignment and letter agreement must be construed together. By its plain language, it noted, the assignment was subordinate to the terms of the letter agreement, and it would be inappropriate to draw any inference regarding title to the overriding royalty interest solely from the assignment. If the letter agreement was lost or destroyed, Endeavor would be required to present evidence of that fact, which would serve as the predicate for the admissibility of alternative evidence of the document's contents. Not only had Endeavor therefore not established as a matter of law that the Browns' overriding royalty interest had been assigned to Arco, the court finally observed, there existed circumstantial evidence, including Endeavor's payments to the Browns for the interest that Endeavor now claimed, that the Browns had retained ownership.

Deed to Railroad Held to Have Conveyed Fee Title, Not Just Easement

The court in *SRO Land & Minerals, LP v. BNSF Railway Co.*, No. 08-24-00347-CV, 2026 WL 1776724 (Tex. App.—El Paso June 19, 2026, no pet. h.) (mem. op.), construed a 1901 deed from Thomas R. White, Jr. to The Pecos River Rail Road Company, affecting a 100-foot-wide strip of land in Reeves County, Texas. The appellants, the owners of mineral interests in tracts of land traversed by the strip, had sued BNSF Railway Co. (BNSF), the successor to the grantee railroad company, for a determination of title to the minerals underlying the strip. The trial court granted summary judgment to BNSF, decreeing that the 1901 deed had conveyed fee simple title to the land rather than a mere easement, entitling the railroad company to oil and gas royalties. The court of appeals affirmed.

The deed, in its granting clause, conveyed the grantor's interest

> in and to those certain pieces and parcels of land, for the purpose of maintaining and operating the line of railroad owned by the second party thereupon, a way and right of way one hundred (100) feet in width being fifty (50) feet on each side of its main track over, upon and through the following named surveys . . . .

The surrounding mineral owners argued that this wording conveyed only an easement because it stated that it conveyed a "way and right of way" for "maintaining and operating the line of railroad." The court disagreed.

The Texas Supreme Court in *Texas Electric Railway Co. v. Neale*, 252 S.W.2d 451, 454 (Tex. 1952), the court remarked, clarified that the term "right of way" may be used to describe a right of passage over a tract but may also be used to describe the strip of land on which the railroad company constructs its roadbed. Under *Neale*, it continued, courts are directed to look at a deed's granting clause and apply two rules: first, "a deed which by the terms of the granting clause grants, sells and conveys to the grantee a 'right of way' in or over a tract of land conveys only an easement"; and second, "a deed which in the granting clause grants, sells and conveys a tract or strip of land conveys the title in fee, even though in a subsequent clause or paragraph of the deed the land conveyed is referred to as a right of way." *Id.* at 453. Placement of the "right of way" language in a deed is thus significant, in the court's analysis. In the deed considered here, the court pointed out, neither the phrase "right of way" nor any other language suggesting an easement or restriction on the conveyance appeared in the granting clause; instead, the phrase appeared in the statement of purpose, after the granting clause's description of the property conveyed. The placement of the words "way and right of way" after the words "in and to those certain pieces or parcels of land," the court concluded, indicated the phrase was not intended to limit the nature of the previously described fee simple conveyance but rather to describe the intended use of the land. Under *Neale*, declared the court, a statement of purpose does not reduce or debase what is conveyed in a granting clause if the statement of purpose appears in a subsequent clause or paragraph of the deed. It distinguished its holding in *BNSF Railway Co. v. Chevron Midcontinent, L.P.*, 528 S.W.3d 124 (Tex. App.—El Paso 2017, no pet.), construing a deed granting "for a right of way, that certain strip of land" as having conveyed only an easement on the basis that the phrase "for a right of way" appeared within the granting clause directly in front of the phrase "that strip of land."

Water Purchase Agreement Did Not Restrict Lessee's Access Rights for Oil and Gas Development

Davenport v. EOG Resources, Inc., No. 04-25-00062-CV, 2026 WL 1811019 (Tex. App.—San Antonio June 24, 2026, no pet. h.), decided the disputed extent of the rights of EOG Resources, Inc. (EOG), the oil and gas lessee under a 1967 oil and gas lease, to use the surface of the land covered by the lease.

In 2022 EOG and the surface owners entered into an agreement for EOG's purchase of water from the surface owners' wells for use in its operations in the area. Section 9 of that agreement provided, in its first sentence, "EOG shall enter and exit the [surface owners'] Lands through the Krueger Rd. gate." The same section continued that EOG agreed to use existing roads designated by the surface owners "for ingress and egress to the Frac Pond and/or the designated water wells . . . ."

On March 24, 2023, EOG informed the surface owners that it planned to construct a new access gate, the "Rancho Derecho" gate, and a road across their property for its operations on the land under its oil and gas lease due to inaccessibility from and disrepair to the existing entry point along Krueger Road. It then proceeded, over the surface owners' objections, to construct the new Rancho Derecho gate and a new caliche road leading from it. In the ensuing litigation, the surface owners sought a declaration that the water purchase agreement restricted all of EOG's access to the Krueger Road gate, including access for the purpose of operations under the oil and gas lease. The trial court granted judgment to EOG on the surface owners' trespass action and awarded EOG significant monetary damages for the surface owners' breach of the water agreement. The court of appeals affirmed.

Although the first sentence of the water agreement's Section 9, read in isolation, might support the surface owners' interpretation, the court began, a court must not read contractual phrases in isolation but must utilize a holistic approach. The water agreement contained a clause reciting its purpose to be to provide EOG ingress and egress "for the purpose of producing, operating, and obtaining water from Grantor's Frac Pond . . . and/or designated water wells," it pointed out, and the same purpose was reiterated within Section 9. Had the parties intended to restrict EOG's access *for all purposes* solely to Krueger Road, the court remarked, they could have done so. The only reasonable interpretation of Section 9, the court concluded, was that whenever EOG accessed the frac pond or designated water wells, it must begin and end at the Krueger Road gate, but the water agreement did not limit access for other operations.

The surface owners also asserted that EOG's construction of the new gate and road was a trespass in that it unreasonably interfered with their existing use, violating the accommodation doctrine. To obtain relief on that claim, the court observed, the surface owners had to establish that (1) EOG's use of their land completely precluded or substantially impaired their existing use; (2) the surface owners had no reasonable methods available by which their existing use could continue; and (3) EOG had a reasonable, customary, and industry-accepted alternative available that would allow it to recover its minerals and also allow the surface owners to continue their existing use. Notwithstanding the surface owners' testimony that in conducting wildlife management they flew over the land in a helicopter "looking for hogs and stuff like that," they presented no evidence that EOG's power lines impaired those flyovers, according to the court, nor was there evidence that EOG's construction of a new road completely or substantially impaired the surface owners' existing use or that no alternative existed.

Deeds Construed (1) Not to Have Impliedly Conveyed Grantors' Interests in Executive Rights in Excess of Fractional Mineral Interests Expressly Conveyed, and (2) to Have Reserved Fixed, Not Floating, Royalty Interest

The court in *Ovintiv USA, Inc. v. High Noon Resources, LLC*, No. 11-21-00103-CV, 2026 WL 1992100 (Tex. App.—Eastland July 10, 2026, no pet. h.), was called upon to construe a series of conveyances of mineral interests in the C. C. Slaughter Ranch, consisting of over 25,000 acres of land in Martin County, Texas. The first was a mineral deed from E. H. Chandler and William A. Childress, who had acquired an undivided one-half interest in the mineral estate of the land, to High Crest Realty Company (High Crest), dated August 1, 1958. That mineral deed conveyed to High Crest an undivided 1/4 interest in the minerals and, in addition, the executive right to lease the grantors' retained 1/4 of the minerals, and it contained the following reservation:

> PROVIDED, HOWEVER, Grantors shall be entitled to receive one-fourth (1/4th) of the cash bonus for any such lease, one-fourth (1/4th) of the delay rentals, and one-fourth (1/4th) of the usual one-eighth (1/8th) royalty (and Grantors shall be entitled to 1/4th of the 1/8th royalty irrespective of the amount of royalty actually provided for in any lease executed by Grantee, its successors or assigns), one-fourth (1/4th) of any shut-in gas royalty or penalty royalty, or other payment paid in lieu of actual production and marketing.

In 1961 High Crest executed a mineral deed conveying back to Chandler and Childress one-half of all of the rights conveyed in the 1958 deed, so that Chandler and Childress then jointly owned an undivided 1/4 interest in the executive rights and an undivided 1/8 interest in the remainder of the mineral estate, 1/3 of which interests were shortly thereafter conveyed to Excuderunt, Inc. (Excuderunt). In three mineral deeds executed on October 31, 1962, each of Chandler, Childress, and Excuderunt conveyed to General Crude Oil Company (General Crude) "an undivided one-twenty-fourth (1/24th) interest in and to all of the oil, gas and other minerals in and under and that may be produced from" a portion of the C. C. Slaughter Ranch lands. In the aggregate, the three deeds, on their face, conveyed General Crude an undivided 1/8 of the minerals.

Element Petroleum Properties, LLC (Element) acquired oil and gas leases from the successors to the interests, if any, of Chandler, Childress, and Excuderunt. Element filed suit against lessees of the interest conveyed to General Crude, who claimed their leases covered the entire 1/4 of the minerals over which Chandler, Childress, and Excuderunt had held executive rights. After others on either side of the deeds were joined in the suit, Jase Minerals, LP and Jase Family, Ltd., who had leased to Element, filed a motion for summary judgment seeking a declaration that the grantors in the 1958 High Crest deed only reserved a fixed 1/32 royalty interest, not 1/4 of the royalty at the rate prescribed by the current leases. The trial court granted that motion as well as Element's motion for summary judgment for title to its claimed 1/8 leasehold interest. The court of appeals affirmed.

The court first addressed title to the executive rights and leasehold pursuant to the 1962 deeds. XTO Holdings, Inc. (XTO), the successor to the mineral interest conveyed to General Crude, and PetroLegacy Energy II, LLC (PetroLegacy), its lessee, asserted that the grantors in the 1962 deeds conveyed not only the 1/24 mineral interest that each deed expressly described and conveyed but also the additional 1/24 interest in the executive rights that each grantor held because that interest was not expressly reserved. The court of appeals disagreed, relying largely on *Piranha Partners v. Neuhoff*, 596 S.W.3d 740 (Tex. 2020). The grantors in the 1962 deeds expressed their intent to convey a lesser estate than they owned because they only granted a portion of what they owned, the court held; it was unnecessary for them to except or reserve the executive right in excess of that attributable to the 1/24 mineral interest that they otherwise owned simply because the deed did not convey it. The court went on to reject XTO's and PetroLegacy's argument that as a matter of policy the 1962 deeds should not be construed to result in the creation of a "naked" executive right, finding that existing case law did not render such a right impermissible.

The court then turned to the question of whether the 1958 deed to High Crest had reserved to the grantors a fixed royalty interest of 1/32 of production or instead 1/4 of the royalty at the current lease rate. XTO and PetroLegacy contended that the proviso that followed the deed's grant was not a reservation at all but merely reinforced that the grantors had not parted with the rights to receive bonuses, delay rentals, and royalty payments incident to their 1/4 mineral interest, but that if it was a reservation, it was a reservation of a floating royalty interest. Irrespective of whether it was technically a reservation, the court remarked, it was part of the written conveyance that must be construed to ascertain the nature of the interest the grantors withheld. Although the court acknowledged the announcement by the Texas Supreme Court in *Van Dyke v. Navigator Group*, 668 S.W.3d 353 (Tex. 2023), that the use of a double fraction of 1/8 creates a presumption that the "1/8" is a term of art that actually refers to the entire mineral estate, it also noted that court's recent holding in *Clifton v. Johnson*, 733 S.W.3d 16 (Tex. 2026), emphasizing that the presumption can be rebutted by other language in the same deed. In the 1958 deed at issue here, the court observed, the description of the royalty interest reserved to the grantors did not end with the words "one-fourth (1/4th) of the usual one-eighth (1/8th) royalty"; it continued with the parenthetical phrase that the grantors would be entitled to that interest *irrespective of* the amount of royalty actually provided for in any lease. In the court's analysis, that parenthetical negated one of the foundational bases for the *Van Dyke* presumption—the concept of a "standard and customary" 1/8 royalty in all future leases. Further, the use of the words "irrespective of" untethered the royalty interest being withheld from the royalty amount in a future oil and gas lease. Thus, the court concluded, the parenthetical phrase intended for the reserved royalty interest to be a fixed fraction of total production, not tied to the royalty interest provided for in future leases, rebutting the *Van Dyke* presumption.

Editor's Note: The reporter's law firm has represented Element Petroleum and the successor to its interest in this case.

Reservation of 1/2 of the Usual and Customary 1/8 Royalty, Also Described as the Right to Receive 1/16 of Oil and Gas Produced, Held "Floating" 1/2 of Lease Royalty

Shorter v. Coffield Family Properties, Ltd., No. 11-25-00251-CV, 2026 WL 2117288 (Tex. App.—Eastland July 23, 2026, no pet. h.), construed a 1944 deed conveying a section of land in Borden County, Texas. The deed reserved to the grantors "as a royalty interest an undivided one-half of the usual and customary one-eighth (1/8) royalty on all oil, gas and other minerals in, on and under the above described lands," nonparticipating in leasing rights and rights to receive bonuses and rentals, further providing, regarding any leases executed by the grantee, "the sole and only right of the grantors herein being to receive one-sixteenth (1/16) of all oil and gas and other minerals produced from said lands as a royalty interest on any such production . . . ." The trial court had granted Coffield Family Properties, Ltd. and others, successors to the interest of the grantors, summary judgment declaring the deed to have reserved a floating royalty interest of 1/2 of the royalty on production, as opposed to a fixed 1/16 of production, and the court of appeals affirmed.

The court relied on the presumption announced in *Van Dyke v. Navigator Group*, 668 S.W.3d 353 (Tex. 2023), that the use of a "double fraction" of 1/8 means the stated fraction of all, not just of 1/8. It acknowledged that the presumption is rebuttable by other wording in the instrument that created the interest and that the Texas Supreme Court in *Clifton v. Johnson*, 733 S.W.3d 16 (Tex. 2026), held a deed's use of a single fraction (1/128) rebutted the presumption that might have arisen from the deed's later reference to the interest being conveyed as "1/16 of the usual 1/8 royalty." The court distinguished *Clifton* on the basis that the double fraction in the 1944 deed at issue appeared in the reservation of that interest and that the single fraction was in the deed's future-lease clause, the opposite of the locations of the respective double and single fractions in the *Clifton* deed.

UTAH – OIL & GAS

Rohit Raghavan, Reporter

New Bonding Requirements Implemented for Oil and Gas Wells

Bonding requirements have increased to keep pace with the rising costs of plugging orphaned oil and gas wells. Effective July 8, 2026, Utah Administrative Rule R649-13 established new performance bond requirements for most oil and gas activities. In particular, the prior $120,000 blanket bond for operating multiple wells was replaced by a tiered pricing system beginning at $200,000 for up to 10 wells and potentially increasing to $5 million, depending on factors including the operator's total number of wells in the state and their average true vertical depth (TVD). To qualify for a blanket well performance bond, however, an operator must meet a total well production requirement (ranging from 200 to 1,000 barrels of oil per day over a one-year period) and maintain an at-risk well ratio not exceeding 25%. An operator that does not qualify must provide individual depth-based well performance bonds ranging from $5,000 to $110,000, depending on each well's TVD. The Division of Oil, Gas and Mining may require replacement of a performance bond if coverage becomes insufficient or upon a change of operator. The rule also requires the base bond schedule to be reviewed and adjusted for inflation at least every five years.

Separate bonding requirements apply to federal oil and gas leases. On June 22, 2026, the U.S. Department of the Interior announced proposed revisions to the Bureau of Land Management's oil and gas leasing regulations. The proposed rule would reduce the minimum statewide bond covering an operator's federal leases and operations within one state from $500,000 to $25,000. It would also reduce the minimum individual lease bond from $150,000 to $10,000. *See* Oil and Gas Leasing, 91 Fed. Reg. 38,084 (proposed June 24, 2026) (to be codified at 43 C.F.R. pts. 3000–3180).

CANADA – OIL & GAS

Ashley M. White, Jason Roth, Larissa Lees, Tinashe Muzah, Evan Hall & Joel Palyga, Reporters

Alberta and Canada Sign Co-Operation Agreement to Reduce Project Assessment Duplication

On April 2, 2026, the Government of Alberta (Alberta) and the Government of Canada (Canada) announced the execution of a finalized Co-operation Agreement on Environmental and Impact Assessment (Co-operation Agreement). The Co-operation Agreement establishes a framework for Canada and Alberta to reduce duplication and work toward a more streamlined approach to assess proposed projects subject to both an impact assessment under Canada's *Impact Assessment Act* (*IAA*) and an environmental assessment under Alberta's *Environmental Protection and Enhancement Act* (*EPEA*). The Co-operation Agreement signals a continued shift toward a streamlined and predictable regulatory and investment environment for project development in Canada.

Under the *Constitution Act, 1867*, the federal and provincial governments are assigned express jurisdictions, or heads of power, in which they may exercise their lawmaking function. The scope and scale of major projects often result in overlapping jurisdictional authority between the federal and provincial governments in relation to project development. For example, the provinces have exclusive legislative jurisdiction over the development and management of non-renewable natural resources within their borders; however, the federal and provincial governments share responsibility for the environment and consultation with Indigenous Peoples. As a result, both the federal and provincial governments have asserted that they have lawful authority to regulate certain aspects of major project development, and have each created their own distinct project assessment processes. Historically, there was no formal framework to harmonize the federal and provincial assessment processes when a project was captured under both legislative frameworks, resulting in duplicative processes often conducted under different criteria. This required project proponents to prepare two reports, navigate two government assessment processes, and then await two separate decisions before proceeding with project development.

The Co-operation Agreement reflects Canada's new policy objective of a "one project, one review" approach, intended to enhance the efficiency of federal and provincial regulatory and permitting processes for major projects and provide certainty to proponents, Indigenous partners, investors, and stakeholders. A fundamental pillar of the "one project, one review" approach is reaching co-operation agreements with the provinces to facilitate a streamlined process that aligns the federal review process with that of the specific province. The Co-operation Agreement between Alberta and Canada is one of seven agreements the federal government has reached with the provinces as of July 2026, illustrating a concerted effort by both the Impact Assessment Agency of Canada (IAAC) and the provinces to implement and support the "one project, one review" vision *vis-à-vis* Canada's major project push.

In the Alberta-Canada context, the Co-operation Agreement follows a memorandum of understanding (MOU) signed on November 27, 2025, in which the federal and Alberta governments committed to negotiate a co-operation agreement on impact assessments. The Co-operation Agreement marks an important evolution in the Canada-Alberta relationship, particularly in executing the MOU's goals of:

- building a low-emission bitumen pipeline to the west coast;
- building and financing the world's largest carbon capture, utilization, and storage project; and
- constructing energy infrastructure for AI computing power and inter-provincial integration.

<u>Overview of the Co-operation Agreement Framework</u>

The Co-operation Agreement establishes a shared framework intended to reduce duplication and support coordinated assessment processes between federal and provincial regulators. For projects that are primarily within Alberta's jurisdiction, Canada will rely on Alberta's assessment and regulatory processes, including, where applicable, to address effects within federal jurisdiction. For projects located on federal land or involving federal undertakings, Canada will integrate Alberta's assessment and regulatory processes into the federal assessment process—if "applicable and desired" by Alberta. For projects requiring both federal and provincial assessments, Canada and Alberta will develop an arrangement addressing roles, responsibilities, activities, and timelines, with the objective of achieving a coordinated or single assessment process that satisfies both jurisdictions' legislative requirements.

To support this framework, the Co-operation Agreement provides for:

- Early notification and information sharing: The IAAC and the applicable Alberta Regulator (such as the Alberta Energy Regulator or the Alberta Utilities Commission) will notify each other as early as possible of proposed projects that may trigger both federal and provincial assessments under the *IAA* and the *EPEA*, respectively.
- Support for addressing federal effects: Where Canada relies on Alberta's processes, Canada will provide support and expertise as appropriate in relation to effects within federal jurisdiction.
- Co-ordination of assessment processes: The parties will coordinate assessment approaches, including information requirements, timelines and opportunities for public and Indigenous participation, where both federal and provincial processes apply.
- Cross-jurisdictional projects: For projects that cross provincial or territorial boundaries, Canada and Alberta will seek to apply the principles of the Co-operation Agreement in coordination with the relevant jurisdiction.

- Dispute resolution: A dispute resolution process is provided for, under which disagreements regarding interpretation or implementation are to be addressed through consultation and cooperation, beginning at the working level and escalating, where necessary, to senior officials.

Canada also commits to completing any federal assessment required under the Co-operation Agreement within a maximum of two years from receipt of the initial project description, in accordance with the IAAC's policies and guidelines.

Either government may terminate the Co-operation Agreement upon 90 days' written notice; however, such termination does not apply retroactively to any projects already underway on the day of termination.

<u>Indigenous Consultation and Participation</u>

For projects primarily within Alberta's jurisdiction, Canada will recognize Alberta as best placed to consult with Indigenous Peoples on such projects pursuant to Alberta's consultation policies and practices; however, Canada will continue to consult with Indigenous Peoples on federal decisions under the *IAA*. The Co-operation Agreement emphasizes early engagement, including timely notification to Indigenous groups regarding proposed projects and assessment processes. Canada also commits to working with Indigenous Peoples on sharing and protecting Indigenous Knowledge, and Alberta commits to receiving, sharing, and considering Indigenous Knowledge. In addition, Canada and Alberta will coordinate federal funding to support Indigenous participation in assessment processes and will seek to coordinate open, transparent, effective, and timely communications with the public to support participation in assessments.

<u>Jurisdictional Considerations</u>

The Co-operation Agreement provides that neither government cedes nor limits any jurisdiction, rights, powers, privileges, prerogatives, or immunities by entering into the agreement. The Co-operation Agreement further confirms that Alberta is challenging the constitutionality of the *IAA* and does not accept that the *IAA* is constitutional. Alberta's position remains unchanged following the Supreme Court of Canada's October 2023 decision that the *IAA* was unconstitutional and Canada's subsequent amendments to the *IAA* in April 2024. Alberta continues to advance its constitutional challenge, which the Alberta Court of Appeal heard in February 2026 but had not decided as of the submission of this report. For more information, see Vol. 41, No. 1 (2024) of this *Newsletter*.

<u>Conclusion</u>

The Co-operation Agreement forms part of a broader set of policy initiatives by both Canada and Alberta aimed at streamlining approval and regulatory frameworks for major projects. These include the federal Major Projects Office established in September 2025, the federal *Building Canada Act*, and Alberta's *Expedited 120-Day Approvals Act*. The latter was passed on May 6, 2026, and implements a 120-day major project approval timeline for qualified projects. Alberta has articulated the *Expedited 120-Day Approvals Act* as its legislative response to the MOU, and will work within the Co-operation Agreement's framework to fast-track projects when Alberta leads a project assessment.

While implementation details remain to be developed, the Co-operation Agreement's alignment between federal and provincial initiatives signals a continued policy focus on reducing duplication and improving timeliness and predictability in project approvals. If effectively implemented, the Co-operation Agreement, in conjunction with other major project initiatives, may enhance regulatory certainty and improve the investment environment for major energy, infrastructure and resource projects in Canada.

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Volume 43 | Number 3 | 2026
ISSN 2768-7821