Institute for ENERGY LAW
THE CENTER FOR AMERICAN AND INTERNATIONAL LAW

JULY 2026
VOL. 20 | NO. 2

ENERGY LAW ADVISOR

INDUSTRY UPDATES

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FERC Streamlines Natural Gas Permitting in Support of Infrastructure

James D. Seegers, Suzanne E. Clevenger, Brandon Tuck, William Scherman, Thomas Knight, Jason Fleischer, Andrew N. Beach, Victoria Galvez Godfrey, and Justine Jia, Vinson & Elkins LLP

On June 18, 2026, the Federal Energy Regulatory Commission ("FERC" or the "Commission") announced two orders at its June 2026 Open Meeting that will streamline approvals of natural gas infrastructure projects by adhering more closely to statutory requirements and relatively recent Supreme Court precedent.

- In an order approving Eastern Gas Transmission and Storage, Inc.'s Appalachian Reliability Project (the "Eastern Gas Order"), the Commission clarified that the National Environmental Policy Act ("NEPA") does not mandate a cumulative effects analysis that extends beyond the reasonably foreseeable effects of the project directly before the agency. This order follows the Supreme Court's decision in *Seven County Infrastructure Coalition v. Eagle County, Colorado* ("*Seven County*") in May 2025 that expressed an agency's ability to establish reasonable limits on the scope of its NEPA review. However, cumulative effects are not out of the picture entirely, as the Commission noted that an analysis of "other activities in the vicinity" can help the agency satisfy its obligation to contextualize its review of the project at hand.
- The Commission's order authorizing construction of Cheniere Creole Trail Pipeline's Gillis Header Project (the "Creole Trail Order") also clarified that only filings that adhere to regulatory requirements for protests in prior notice proceedings will be considered protests, departing from FERC's history of construing a wide range of comments and filings as protests, thus limiting procedural obstructions to prior notice requests and projects.

Together, these orders advance the Commission's goal of making environmental reviews more efficient to build infrastructure that, in the words of Chairman Laura Swett, is "desperately need[ed]."

The Shrinking Scope of Cumulative Effects

Key takeaways:

- ***Permitting Efficiency.*** FERC is "working hard at reforms that will streamline gas permitting" and reduce procedural burdens. The Eastern Gas Order clarifies that FERC will no longer analyze cumulative effects in standalone sections of its NEPA reviews, with more focus placed on the project under review.
- ***Context-based approach remains.*** FERC will continue to consider project-related impacts cumulatively with impacts from activities "in the vicinity" of proposed projects. Thus, FERC can ensure a properly contextualized review, even if it does not include all conceivable projects across larger areas.
- ***Guidance for applicants.*** While reforms can expedite initial project approvals, project opponents will undoubtedly continue to scrutinize agency practices and look for creative or novel litigation strategies to challenge and derail projects. Applicants should continue to evaluate the impacts of other activities occurring in the vicinity, i.e., near the "time and place" of the project, to ensure a robust record that addresses impacts from the project combined with those from activities occurring in the vicinity of the project. This will help ensure that resulting Commission orders are defensible in litigation.

NEPA requires FERC to consider the "reasonably foreseeable environmental effects" of its actions, such as authorizing natural gas infrastructure projects under the Natural Gas Act ("NGA"). The extent to which agencies need to consider the impacts of other activities—including the potential "upstream and downstream" activities and effects "that are separate in time or place from" the project before the agency in their NEPA review has long been a point of contention, in some cases turning NEPA's procedural requirements into a "blunt and haphazard tool" used to delay or stop infrastructure development. Under the now-rescinded Council on Environmental Quality ("CEQ") regulations, agencies often separately evaluated a project's cumulative effects—the incremental effects of an action when considering other past, present, and reasonably foreseeable future actions. In some instances, this led agencies to consider potential effects that were far afield of those related to the project before them. In *Seven County*, the Supreme Court clarified that agencies need not consider impacts from projects that are "separate in time or place," are outside the instant agency's regulatory authority, or that would be initiated "if at all, by third parties."

In announcing the Eastern Gas Order, FERC Chairman Swett explained that the Commission's NEPA reviews to date "ha[ve] not fully capitalized on recent legislation, the Supreme Court's decision in ***Seven County***, and CEQ's rescission of NEPA regulations." Noting that NEPA itself does not explicitly reference cumulative effects, the Eastern Gas Order clarified that FERC need not continue to identify a "distinct and separate category" of cumulative impacts, since it exceeds what NEPA requires and contributes to "undue procedural burdens" on applicants and agency staff. The Eastern Gas Order acts to bring FERC's NEPA procedures more in line with how many other federal agencies updated their NEPA procedures (which we discuss here), especially in how FERC did not entirely jettison the concept behind the traditional cumulative effects analysis. Although many other agencies do not require specific discussion of cumulative effects, they maintain procedures ensuring that the agency's environmental analysis considers the context in which the project's effects occur. The U.S. Department of Agriculture, Department of Energy, and Department of the Interior, for example, explain that environmental effects are evaluated "in the context of the potentially affected environment" while considering "trends and planned actions in the area."

The Eastern Gas Order takes a similar approach. Importantly, in a nod to ***Seven County***, it emphasizes that FERC will consider impacts from activities "in the vicinity of a proposed project" as necessary to help the Commission fulfill its NEPA obligations, as this ensures a "holistic and properly contextualized" review of the reasonably foreseeable impacts of the proposed action. The context-based approach espoused in the Eastern Gas Order allows the Commission to continue considering certain impacts that were previously within the "cumulative impacts" category, albeit on a scale more closely tied to the project at hand. The Commission has experience in addressing these types of cumulative impacts using other terminology, such as when FERC's NEPA documents prepared under a prior version of the CEQ regulations included a discussion of "Environmental Trends and Planned Activities" rather than a dedicated cumulative effects section, despite the continuing reference to cumulative effects in the Commission's own regulations. FERC Staff may seek to undertake a similar, more context-driven approach to cumulative impacts. Cumulative impacts are unlikely to completely disappear from FERC NEPA reviews. Under the Eastern Gas Order, FERC Staff will continue to consider the impacts of activities "in the vicinity" of a proposed action—such as a power plant located next to a proposed pipeline that will be under construction at the same time as the proposed pipeline or other activities occurring adjacent to a new compressor station that could result in additive impacts—but will no longer dedicate separate sections in NEPA documents to identifying all past, present, and foreseeable projects across large swathes of land that frequently offer little useful information and that do not help contextualize the actual impacts of the project being evaluated. To ensure more robust and defensible Commission orders, applicants should continue to evaluate the impacts of other activities occurring in the vicinity of the project. Applicants should evaluate and consider those impacts within the context of the discussion of the project's effects, which will help ensure that resulting Commission orders can stand up to judicial review.

It remains to be seen how or when the Eastern Gas Order may be reflected in the Commission's regulations and guidance documents governing environmental reports for NGA applications. However, as Chairman Swett previewed, there is "more to come," and it remains possible that FERC may ultimately go through the formal process to update its NEPA regulations to remove references to "cumulative effects."

Reforms to Blanket Certificate Proceedings

Key takeaway:

- *Strict adherence to regulations.* The Creole Trail Order clarifies that filings in blanket certificate proceedings that do not clearly meet the regulatory requirements for protests will no longer be considered as such, ensuring nonspecific opposition or mere comments will not derail projects that otherwise qualify for blanket authorization.

The Commission announced that it would strictly apply its regulation governing what constitutes a protest under its blanket certificate program. FERC's blanket certificate program allows natural gas companies to file a "prior notice" of blanket activity to obtain authorization under Section 7 of the NGA for certain limited-scope activities within Commission-set cost limits without seeking a separate, case-specific certificate order. Projects are automatically authorized so long as no protests are filed within 60 days of notice of the project; or if a protest is timely filed, such protest must be dismissed by the Director of the Office of Energy Projects within 10 days of filing or withdrawn within 30 days of the end of the notice period for the project to be automatically authorized. Though the Commission's regulations set out strict requirements defining what qualifies as a "protest," the Commission has historically accepted more general comments as protests—even if nothing in the filing indicates the comment was intended as such.

The Commission's Creole Trail Order clarifies that filings in blanket proceedings that do not meet clearly defined regulatory requirements "will not be considered protests by the Commission and will not necessitate a Commission order." By adhering to its nearly 50-year-old regulatory text, FERC's order ensures that nonspecific opposition or mere comments on a prior notice filing will not obstruct a project that otherwise meets the requirements to proceed under blanket authorization.

This order is the latest in the Commission's actions regarding its blanket certificate procedures with an eye towards streamlining infrastructure proceedings. In May 2026, the Commission announced a Notice of Proposed Rulemaking to revise its blanket certificate program to, among other reforms, increase the cost limits for projects that may be constructed under a blanket authorization and expand the blanket certificate program to encompass expansions of existing compressor stations that increase capacity, regardless of cost, when those projects are located within existing facilities' footprints. If ultimately adopted, these revisions would allow a greater scope of critical infrastructure projects to take advantage of these more efficient permitting procedures.

Environmental Justice Regulatory Update: Federal EJ Rollbacks, State EJ Laws, and Compliance Risks for Businesses in 2026

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Environmental justice (EJ) requirements are moving in two different directions at once: federal programs are being scaled back, while many states are pressing ahead with their own EJ laws, screening tools, and permitting expectations. For companies with operations in multiple jurisdictions, that means compliance may depend less on a single federal framework and more on a state-by-state analysis. This update breaks down the most important federal rollbacks, state responses, and litigation trends shaping the EJ landscape in 2026. It also highlights practical steps businesses can take now to monitor risk and prepare for continued regulatory change.

Highlights:

- Federal EJ Rollbacks: The administration has rescinded major EJ executive orders, closed federal EJ offices, narrowed enforcement tools, and shifted EPA policy away from prior EJ priorities.
- State-Level Momentum: California, New York, New Jersey, Colorado, Maryland, Pennsylvania, and other states continue to advance EJ statutes, screening tools, cumulative impact reviews, and permitting requirements.
- Litigation and Grant Uncertainty: Court challenges involving EPA grant cancellations, state EJ permitting authority, and citizen suits may shape the next phase of EJ-related compliance and enforcement risk.
- Business Compliance Priorities: Companies should evaluate state-specific EJ obligations, monitor preemption disputes, and plan for a more fragmented regulatory environment.

For previous coverage on this topic, see our April 2024 Environmental Justice Update and our January 2025 Alert on President Trump's Executive Orders to Eliminate Federal Environmental Justice Programs.

The EJ regulatory landscape has shifted significantly over the past year. At the federal level, the administration has rescinded the executive orders (EOs), offices, and enforcement policies that formed the foundation of federal EJ programs. At the same time, state governments—led by California, New York, and New Jersey, but also extending to Colorado, Maryland, Pennsylvania, and others—have continued to develop and implement their own statutes, screening tools, permitting standards, and enforcement practices that embed both procedural and substantive EJ requirements. This divergence is reshaping the regulatory environment for businesses operating across jurisdictions, creating a patchwork of obligations that in many cases differs from, and in some states exceeds, what existed under the prior federal framework. Concurrently, nonprofit organizations and citizen groups have brought suits under alternative authorities seeking damages and injunctive relief for actions that impact economically disadvantaged communities. This Alert surveys the key federal and state developments over the past twelve months and identifies the practical implications for companies navigating this evolving landscape.

Federal Developments

As detailed in our January 2025 Alert, the Trump administration has rescinded many EOs aimed at promoting federal environmental justice policy, including Clinton's EO 12898, Biden's EO 14096, and the Justice40 Initiative (EO 14008), and directed the termination of all federal EJ offices and programs. Our prior Alert also flagged uncertainty about the future of Environmental Protection Agency (EPA)-administered Inflation Reduction Act (IRA) grant programs. Since then, those changes have taken effect, and the Trump administration has taken additional actions extending into enforcement policy, civil rights, regulations, and Clean Air Act authority. The following is a consolidated timeline of the most significant developments since our last Alert.

Elimination of Federal EJ Programs

Since our last Alert, the US Department of Justice (DOJ), EPA, and other agencies have taken additional steps to eliminate federal EJ programs and narrow the scope of EJ-related considerations in federal permitting activities:

- **February 2025:** DOJ terminated its Office of Environmental Justice and rescinded the joint EJ enforcement strategy with EPA.
- **March 2025:** EPA terminated the National Environmental Justice Advisory Council (NEJAC).
- **March 2025:** EPA formally eliminated the Office of Environmental Justice and External Civil Rights (OEJECR).
- **May 2025:** EPA closed its air pollution/human studies research facility in Chapel Hill, North Carolina.
- **September 2025:** The Federal Transit Administration withdrew its EJ guidance.
- **December 2025:** DOJ amended its Title VI implementing regulations to eliminate disparate impact liability.
- **December 2025:** EPA adopted a "Compliance First" policy halting the use of Supplemental Environmental Projects (SEPs).
- **January 2026:** EPA proposed a rule limiting state authority to block infrastructure projects under the Clean Water Act.
- **February 2026:** EPA rescinded the 2009 endangerment finding for greenhouse gas emissions under the Clean Air Act and repealed related motor vehicle GHG regulations.
- **March 2026:** EPA closed its Office of Research and Development.
- **May 2026:** EPA issued Clean Air Act Title V guidance aimed at expediting the permitting process for major sources of air pollution.

Federal Grant Programs

EPA has now canceled dozens of EJ-related contracts and grants that made up a significant portion of the US$3 billion that Congress appropriated through the IRA for the Environmental and Climate Justice (ECJ) Program. Multiple groups filed suit, and on June 11, 2026, a federal court granted partial summary judgment in favor of the plaintiffs, declaring EPA's termination of the ECJ Program "arbitrary and capricious" and vacating the agency's guidance closing the program. The court denied injunctive relief requiring EPA to restart the program, citing practical difficulties, but noted that the plaintiffs may pursue individual grant claims in the Court of Federal Claims. Companies and grantees affected by the cancellations should monitor whether EPA appeals or takes further action before the September 30, 2026 statutory deadline for awarding the grant funds.

State Developments

As the federal government has continued to eliminate its EJ programs, states have accelerated the development and implementation of their own EJ requirements. Several notable developments illustrate this trend:

- In California, in September 2025, SB 352 was signed into law codifying a Bureau of Environmental Justice within the state Department of Justice and strengthening community air monitoring requirements.
- In New York, in April 2026, the New York State Department of Environmental Conservation (NYSDEC) adopted amendments to its State Environmental Quality Review Act (SEQRA) regulations requiring lead agencies to evaluate whether proposed actions may cause or increase a disproportionate pollution burden on disadvantaged communities (effective June 12, 2026).
- In New Jersey, in January 2026, an appellate panel upheld the state's authority to impose EJ-based permitting requirements.
- Other states, including Colorado, Maryland, and Pennsylvania, have introduced or advanced EJ screening tools, cumulative impact requirements, and enhanced permitting standards.

Key Takeaways

The elimination of federal EJ programs has triggered a growing patchwork of state-level requirements—each with their own definitions of "overburdened communities," their own screening tools, and their own permitting and enforcement consequences. For companies operating in multiple jurisdictions, the result is a more complex compliance landscape. Companies should consider the following:

Evaluate state-level exposure. Businesses should assess their operations in states with active EJ programs, particularly California, New York, New Jersey, Colorado, Maryland, and Pennsylvania, and ensure that their practices account for state-specific requirements.

Monitor the litigation landscape. EJ-related litigation, such as the challenge to EPA's cancellation of IRA-funded grants (which must be awarded by September 30, 2026) and the recent decision upholding New Jersey's state EJ rules, will continue to shape the boundaries of both federal and state regulatory authority. Judicial outcomes may have cascading effects on permitting timelines, compliance obligations, and potential exposure to enforcement actions. Groups like the National Association for the Advancement of Colored People (NAACP) and Earthjustice have also sought to use alternative means to achieve EJ goals. For example, in April, these organizations filed an action in the Northern District of Mississippi under the citizen suit provision of the Clean Air Act seeking to enjoin construction of the Colossus Data Center gas plant in a majority-Black community.

Prepare for potential preemption conflicts. EPA's proposed repeal of the endangerment finding for greenhouse gases, its proposed limitations on state authority to block infrastructure projects, and the elimination of disparate impact regulations all signal a federal posture that may create tension with state-level EJ requirements. Companies operating in jurisdictions where federal and state approaches diverge should monitor preemption developments and formulate compliance strategies that account for both potential outcomes.

Texas Supreme Court Narrows Jury Finding on Scope of Utility Company's Easement by Estoppel

Kat Statman, GableGotwals

In a significant decision impacting the utility and energy industries, the Texas Supreme Court recently issued an opinion in *Boerschig v. Rio Grande Electric Cooperative, Inc.* ("*Boerschig*"), making clear the limited scope of an easement by estoppel.

Private land in Texas, with one of the highest rates of private land ownership (more than 96%) and the second largest state by land size in the United States, is crisscrossed with utilities and energy extraction and delivery operations that date back more than a century. As a result, the recent opinion issued by the Texas Supreme Court, which concluded that easements by estoppel are to be narrowly construed in terms of scope, may have an impact on any utility or energy easement holders that are not properly recorded for historical reasons, significantly limiting what the easement holder can and cannot do within its easement rights.

In *Boerschig*, the Texas Supreme Court was tasked with determining:

- Whether an electric cooperative held an easement by estoppel for its power distribution lines that were built pursuant to an agreed, albeit unrecorded, easement with the prior ranch owners; and
- Whether the scope of that easement by estoppel allowed the electric cooperative to upgrade the power distribution lines that increased the number of power lines originally constructed.

Based on these questions, the Texas Supreme Court concluded that the electric cooperative *did have* an easement by estoppel; however, in a significant decision, the Court concluded that the power distribution line upgrades *exceeded the scope of the easement by estoppel* because the cooperative did not offer any evidence "that the upgrade was reasonably necessary to continue its existing use of the line."

What Happened?

The [Rio Grande Electric Cooperative] ("Rio Grande") was originally formed in 1945 to provide electricity to rural ranches and property owners in south, central, and west Texas. Since 1945, Rio Grande has expanded to cover 18 counties in Texas and two in New Mexico. In 1947, Rio Grande acquired a "Right of Way Easement" over the property at issue, giving it "the right to place, construct, operate, repair, maintain, relocate and replace an electric transmission or distribution line or system on 5,684 acres" of the property at issue. However, the easement was never recorded in the real property records.

The distribution line was constructed after Rio Grande obtained the easement and crossed 1.6 miles of the property at issue. Subsequently, in 2002, John Boerschig purchased the U-Bar Ranch in Kinney County, Texas, which included the plot of land where Rio Grande's utility easement ran. Mr. Boerschig was aware of the distribution line at the time of purchase, as he observed the distribution line in addition to the fact that it was marked on a survey that was prepared in connection with the purchase transaction.

In 2012, Rio Grande provided notice to Boerschig about its plan to bulldoze and upgrade the existing feeder along the utility line easement. Additionally, Rio Grande planned to move the distribution line approximately 15 feet and add to the line to serve new customers (specifically a gas compressor station and a new electric substation Rio Grande was planning to build to accommodate anticipated future demand and growth). While Boerschig contended that he never received the letter, after observing a bulldozer for Rio Grande starting to clear a route through his property, he demanded copies of the easements covering the route. Rio Grande did not provide the specific easement covering the area at issue, only providing other easements it held over the property.

Boerschig filed a suit against Rio Grande for trespass and obtained a temporary restraining order. Rio Grande filed a counterclaim seeking a declaratory judgment that it had a valid express easement or, in the alternative, that it had a prescriptive easement or one by estoppel. During the course of the litigation, the parties agreed Rio Grande would cease construction. Rio Grande also alleged that Boerschig had interfered with its easement rights and potential contracts to reroute the distribution line through the town of Brackettville, Texas.

Throughout the litigation, Boerschig offered to allow Rio Grande to build a new line in a different area of his property and alongside a different existing transmission line owned by another company. Rio Grande, however, refused. After Boerschig dropped his opposition to the continued construction, subject to his trespass claim that the upgrade was not authorized by a valid and enforceable easement, Rio Grande decided to keep the line on the original footprint, but upgraded it to include additional poles and lines as originally planned.

The dispute between the parties eventually went to trial, and the jury returned a verdict that Rio Grande did not have a written or prescriptive easement but concluded that it did have an easement by estoppel. The jury also concluded that Rio Grande's upgrade to the distribution lines failed to exceed the scope of the easement, which included utilizing 60 poles carrying seven wires versus the original distribution line that was 20 poles carrying four wires.

On appeal, the Court of Appeals was presented with two questions:

1. Whether there was sufficient evidence for the jury to find that there was an easement by estoppel; and
2. Whether there was sufficient evidence for the jury's failure to conclude that the transmission line upgrades by Rio Grande exceeded the scope of the easement by estoppel.

The Court of Appeals found that there was sufficient evidence for both jury findings.

Supreme Court's Fundamental Legal Analysis

Whether There Was Sufficient Evidence for Easement by Estoppel Jury Finding

The elements to prove a claim of easement by estoppel are relatively well-settled under Texas law.

1. "[T]he owner of the burdened estate represented that an easement would be conveyed,
2. The holder believed the representation, and
3. The holder relied on the representation to its detriment."

The question the Supreme Court focused on was whether the defective easement, because it was unrecorded, could be evidence to establish Rio Grande's easement by estoppel claim.

The Texas Supreme Court answered this in the affirmative and upheld the Court of Appeals, while declining to adopt the Restatement (Third) of Property. As the Supreme Court stated:

> A writing that fails as an express easement can be some evidence supporting the representation element of an easement by estoppel. The function of such easement is to preserve reliance interests for uses of land intended by the parties but not supported by formal written documentation. Thus, easements by estoppel arise only in cases in which an express easement fails to cover the use at issue. An easement that the parties intended but failed to perfectly memorialize is no less relevant than an easement the parties intended to memorialize by a handshake.

Based on this, the Court concluded that there was legally sufficient evidence based on the unrecorded written easement from 1947 that the jury could rely on finding that Rio Grande had an easement by estoppel.

Did Rio Grande's Upgrade Exceed the Scope of its Easement by Estoppel

The second issue presented to the Supreme Court was on the scope of the easement by estoppel and whether the upgrades by Rio Grande exceeded its scope. This is where the Supreme Court reversed both the trial court and the court of appeals' conclusions, finding that as a matter of law Rio Grande exceeded the scope of its easement by estoppel under Texas law. Therefore, Boerschig, the property owner, is entitled to judgment as a matter of law on his trespass claim.

In coming to this conclusion, the Supreme Court specifically looked at the public policy surrounding easements by estoppel. As the Court noted, because easements by estoppel are not recorded like express easements, determining their scope is more difficult and is fraught with other considerations, like this situation where the easement would be extended to subsequent property owners such as Boerschig. Based on this, the Court stated "[T]he scope of such an easement [by estoppel] is limited to preventing injustice by protecting the holder's reliance interest—that is, the actual investment (or other change of position) that the holder made to use the land in reasonable reliance on the owner's representations." Based on this, the Court made clear that easements by estoppel are limited in scope to that which "would be discovered by reasonable inspection or inquiry."

In support of this conclusion, the Court looked closely at separation of powers issues,

> Courts and juries are not free to give away more of a landowner's property rights whenever they feel that the societal benefit of an expanded use outweighs its burden on the landowner. That judgment is for the other branches of government and entities on which they have conferred condemning authority, and our Constitution demands that the landowner be compensated when a greater easement is taken.

There are additional considerations that can be made in assessing whether an easement by estoppel holder exceeded the scope of its easement, such as whether the activity is "reasonably necessary to fairly enjoy the usage rights defined by the representations, reliance, and knowledge." This assessment of whether the use is reasonably necessary must be narrowly drawn, however, "to burden the landowner as little as possible."

In undertaking this analysis, the Supreme Court concluded that Rio Grande's increasing the number of distribution line poles, increasing the height of those poles by seven feet, and increasing the number of lines on those poles was not an activity that was reasonably necessary for it to enjoy the usage of the easement based on the representations it received and relied upon as well as the knowledge of the easement.

In essence, the issue boiled down to whether Rio Grande could continue to use and maintain its line in its present form, which was not contested. However, the Rio Grande CEO testified that the changes made constituted an upgrade and would provide electric services to a new gas compressor station as well as connect a new electrical substation to accommodate anticipated future growth. The CEO also testified that the existing line served roughly 1,000 consumers. This testimony at the trial court showed that under the narrow construal of the easement by estoppel, Rio Grande had exceeded its scope because it was taking additional steps beyond simply using and maintaining the distribution line and easement that had been in place since the 1940s.

On this basis, the Court concluded as a matter of law that Rio Grande trespassed on Boerschig's property when it upgraded the distribution line and remanded the case to the trial court for further proceedings regarding the appropriate relief.

Key Takeaways

With Texas' historic amount of private property, utility and energy companies are often holders of easements that crisscross private landowners' land. The decision in this case is likely to have an impact on what easement holders can or cannot do within their easement where the easement is not properly recorded. This is likely to be a greater consideration when the land where the easement runs is transferred to a new property owner, as in *Boerschig*. Many of these easements may have been inherited from prior producers or utility companies or granted by prior landowners before the sale of the property to the current landowner. It is fundamental, particularly with these historic property rights, to confirm both that any easements supporting the utility or infrastructure owned are appropriately recorded in the real property records and review the scope of those express easements to ensure that the activity complies with the use and scope of the express easement.

Additionally, it is necessary to understand the narrow limitations on what rights an easement holder may have under the *Boerschig* decision. Under the rule expressed in *Boerschig*, an easement by estoppel will be very narrowly construed in scope, limiting what actions the easement holder may take as reasonably necessary for the use and enjoyment of the limited property right they have.

The *Boerschig* decision underscores the critical importance of proper recording of easements in the property records for utility and energy companies operating across Texas and beyond. Additionally, it underscores the importance of confirming that historical easements, such as the one at issue in *Boerschig*, were recorded in the property records when obtained to avoid the risk of losing an easement or significant narrowing of an easement already negotiated and obtained years prior.

Amendments to Ohio Oil and Gas Statutes Signed Into Law

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Senate Bill 219, recently signed into law by Gov. Mike DeWine, includes changes regarding (i) the leasing of state lands; (ii) the statute of limitations for lawsuits alleging lease expiration; (iii) the regulatory authority of the Chief of the Division of Oil and Gas Resources Management; (iv) procedural requirements for administrative proceedings; and (v) transfers of permits.

State Lands: The following provisions will now be required in leases of state lands: (i) a shut-in royalty of $50 per net mineral acre per year; (ii) an optional extension term of five years rather than three years; (iii) a 60-day payment period for signing bonuses or advanced delay rentals; and (iv) tolling of the primary term and deferment of payments to comply with federal grant requirements, during litigation that prevents operations, or in instances of force majeure. Additionally, statutory deadlines are now imposed. The Oil and Gas Land Management Commission must award the bid within 60 days of approval of the nomination. The state agency whose lands are being leased must execute the lease within 30 days of the Commission awarding a bid, and the lessee must countersign the lease within 45 days after receiving the lease from the agency.

Statute of Limitations for Lease Expiration Lawsuits: A 10-year statute of limitations now applies to lawsuits alleging the expiration of any oil and gas lease.

Cross-State Drilling: Senate Bill 219 clarifies that the Division of Oil and Gas Resources Management has the authority to regulate any portion of a well located in Ohio and allows for the Chief to enter into a memorandum of understanding with the regulatory agency of the other state in which the well is located.

Simultaneous Operations: The Chief cannot require owners of a well to limit or cease production from a well to engage in simultaneous operations on a well pad without good cause.

Administrative Procedure Requirements

- The Ohio Administrative Procedure Act does not apply to orders or notices required to be made by the Chief, including orders and notices in statutory unitization proceedings. The Chief is required to adopt rules setting forth applicable procedures for the service of notices and orders.
- If the Chief imposes conditions on a permit, the applicant may now appeal those conditions to the Ohio Oil and Gas Commission.
- Appeals from orders of the Ohio Oil and Gas Commission are now to be filed in one of the counties in which the unit is located instead of the Franklin County Court of Common Pleas.

Ownership Transfers: When an owner of a permit wants to transfer its interest in a well, it can now provide the Division with most of the new owner's information itself rather than wait for the new owner to provide the information.

Bringing Data Centers to Brownfields

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This article originally appeared in the Summer 2026 issue of Development magazine, published by the Commercial Real Estate Development Association (formerly NAIOP), and is reprinted here with permission.

A framework is in place for understanding and allocating environmental risk.

The redevelopment of brownfield sites into sites for data centers offers unique advantages as well as environmental challenges. Potential site benefits include grid adjacency, established rights of way, zoning, and access to water and other infrastructure. At the same time, site-specific environmental challenges may impact the scope and timeline for development and permitting for new infrastructure.

While data center developers are focused on the development timeline, access to power and stakeholder support, sellers of a brownfield site are most focused on finding a next owner capable of addressing legacy environmental risks in a manner that reduces the possibility of a "boomerang" liability.

Legacy environmental issues at brownfield sites range from minor to significant. An old warehouse could have tiles and insulation containing asbestos, or a transformer might contain polychlorinated biphenyls. Through historical spills and releases, the soil or groundwater at a brownfield site may contain hazardous substances.

Because the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) makes current and former "owners" and "operators" jointly and severally liable for environmental contamination at a site, these historical impacts can present a significant impediment to redeveloping a brownfield for productive use. Developers can evaluate and manage these risks through due diligence, contractual mechanisms and the various brownfield programs aimed at bringing industrial sites back into productive use.

Environmental Due Diligence

At each stage of a diligence effort, developers should ask whether and how the findings affect the viability, cost and timeline of a potential project. Typical diligence tools include database searches, historical aerial photographs, site visits, interviews and a review of existing environmental permits. Helpful questions to ask include:

- How has the historical use of the brownfield site impacted soil and groundwater conditions? Is off-site migration a concern? Do existing conditions pose a risk to neighboring properties that might trigger a more active intervention?
- What concerns do state and local authorities have about legacy liabilities at the site? Are there "buffer" properties that could also be purchased to facilitate redevelopment? Has the site been formally enrolled in any remediation programs?
- Is there legacy infrastructure at the site that may need to be removed, and if so, will it present environmental challenges (e.g., removing asbestos-containing materials from buildings, removing underground piping)? Will the infrastructure be a potential project benefit (e.g., electric transmission lines, tie-ins to neighboring facility processes)?

- Are there legacy permits at the site that present challenges or opportunities? Does an existing permit include closure obligations that require a new owner to conduct investigation and remediation activities?
- Does the seller have existing insurance policies that might mitigate the consequences of discovering unknown contamination during redevelopment?

Contractual Liability and Risk Allocation

Brownfield redevelopment is predominantly structured as an asset sale, not as a lease or a sale of stock or membership interests. Leases are generally disfavored because a continuing role as the owner of the site does not allow the lessor to distance themselves from the legacy liabilities. Stock transactions are often less favorable because the purchaser does not want to acquire other liabilities—such as product, exposure and off-site disposal liabilities—associated with the former business conducted at the site.

Preexisting environmental liabilities: Typically, a purchaser will want the seller to retain responsibility for all preclosing environmental liabilities associated with a site because the purchaser was not in position to control a preclosing presence or release of hazardous substances.

At a brownfield, however, the value of the transaction to the seller is often the opportunity to delay environmental requirements triggered by closing the site and to potentially have someone else remediate preexisting soil and groundwater conditions as part of the redevelopment effort. In such cases, the seller will be focused not only on price but also on the purchaser's likelihood of success and how to ensure the site's legacy liabilities will not boomerang back to the seller should the purchaser fail in its redevelopment efforts.

Representations and warranties: In brownfield transactions, the buyer should expect to purchase the site "as is" and without substantial contractual recourse if environmental surprises arise after closing. The seller's environmental representations and warranties typically focus on the seller's knowledge about environmental conditions and confirmation that they have provided all relevant environmental information in their possession or control. Additional representations may focus on compliance with applicable environmental law and the presence of environmental permits, but these are less of a focus when the buyer plans to redevelop the site. Any indemnity from the seller will likely be limited to a breach of environmental representations. This places a premium on assessing environmental risks prior to closing using due diligence.

Post-closing covenants: After closing, the seller often seeks to ensure the purchaser will fulfill existing site investigation and remediation obligations. This may include obligations for the purchaser to conduct specific work and possibly enter the site into a state-directed remediation program. The seller may also have identified areas of the site that are not suitable for redevelopment or that would potentially trigger environmental risks if disturbed. In that case, the seller may seek negative post-closing covenants restricting the purchaser's ability to utilize such areas.
Separately, the parties can negotiate the parameters of insurance policies that the purchaser must obtain to protect both sides from unexpected environmental issues. In an asset sale, the purchaser may want to acquire the seller's rights under preexisting insurance policies for preexisting environmental issues that are not discovered until the redevelopment work commences post-closing.

Parent guarantees: Purchasers prefer a single-purpose type of entity to own a site with significant environmental liabilities. The purchaser does not want to put its larger balance sheet and resources at risk if redevelopment costs and liabilities prove to be materially higher than anticipated (a practice known as "ringfencing").
On the other hand, the seller may be seeking to minimize the likelihood that conditions at the brownfield site will boomerang back to the seller if the purchaser is unsuccessful. One way for the seller to better insulate against that risk is to require a guarantee from the purchaser's parent entity. The parties must then address whether the guarantee is one of payment, performance or both, as well as the duration of the guarantee.

Voluntary Cleanup Programs

With the Brownfields Amendments to CERCLA, enacted in 2002, Congress sought to alleviate some of the risks brownfield redevelopers faced when returning sites to productive use. Through several memorandums of agreement with the Environmental Protection Agency (EPA), numerous states have established voluntary cleanup programs to help owners and developers perform cost-effective and successful cleanups through coordination with state and federal agencies.

When enrolling a brownfield into a voluntary cleanup program, the owner or developer commits to characterizing and remediating environmental contamination at the site. This work is overseen and supported by technical staff at agencies, who can leverage significant experience in support of cleanup efforts. After the design and implementation of a remedy, many states will issue the owner or developer a certificate of completion, signifying the agency's view that the brownfield has been remediated to appropriate levels. Importantly, this certificate often constitutes a defense to state claims of liability for any future cleanups that may be necessary at the site.

In addition, voluntary cleanup programs offer several other benefits to the entities that pursue remediation to completion. For example, the owner or developer increases the property value of the site and adjacent sites, benefiting nearby landowners and communities. For subsequent real estate transactions, the certificate of completion can provide confidence to prospective purchasers that many of the site's environmental liabilities have been addressed. Conversely, voluntary cleanup programs pull state agencies into the site redevelopment process, which can require a broader scope of investigation and remediation and extend the timeline to completion. The state's role may not prove to be compatible with the rush to get data centers online.

Brownfields 2.0?

The approach outlined above is immediately actionable for data center developers and others seeking to revitalize brownfield sites. Developers should also pay attention to actions taken by the Trump administration to further incentivize data center development at brownfields.

Within days of taking office, President Donald Trump issued an executive order to remove barriers to American leadership in artificial intelligence. It instructed agency officials to prepare an "Artificial Intelligence Action Plan," which was published in July 2025. The AI Action Plan includes a recommendation to streamline numerous environmental permits and requirements that apply to data center developments, including permitting requirements and regulations promulgated under the Clean Water Act, the Clean Air Act and CERCLA. Also in July 2025, the President issued an executive order to accelerate federal permitting of data center infrastructure. It directed EPA to develop guidance for identifying Superfund and brownfield sites and to assist states in returning brownfields to productive use.

In January, EPA published "Guidance on the Redevelopment of Superfund and Brownfield Sites as AI Data Centers." The guidance provides additional information and criteria that may be useful in evaluating brownfield sites for potential redevelopment as data centers.

It remains to be seen whether Congress, EPA or individual states will take steps to further incentivize data center development at brownfields, but the Trump administration's statements make it clear that the race to power AI will be facilitated by favorable policies.

Real estate owners, investors and data center developers should stay up to date on new policies that make brownfields redevelopment even more attractive, while also recognizing that many strategies, contracting tools and programs are already available to bring data centers to brownfields.

Data Centers and Brownfield Sites by the Numbers

450,000+ brownfield sites exist across the United States—a vast inventory of former industrial land with existing power, water and grid infrastructure, many of which are candidates for data center reuse. *Source: U.S. EPA, About Brownfields.*

$3 trillion investment expected by companies in U.S. AI infrastructure to power the next generational of computing. *Source: American Edge Project, America's AI Surge: Powering Investment, Jobs and Growth in Every State.*

9% to 17% of U.S. electricity generation could be consumed by data centers by 2030, up from roughly 4% in 2023, making proximity to existing grid and power infrastructure a critical site selection factor. *Source: EPRI, Powering Intelligence 2026.*

$1.5 billion invested by Congress in EPA's Brownfields Program through the Infrastructure Investment and Jobs Act—the single largest federal investment in brownfields remediation in U.S. history. *Source: U.S. EPA, Infrastructure Investment and Jobs Act: A Historic Investment in Brownfields*.

Can Produced Water from Energy Production Offset Water Scarcity in the Southwest? (Part 1)

Bobby Majumder, Ian Strang, and Edward J. Grattan II, FBT Gibbons LLP

Across the American Southwest, water scarcity and oil and gas development increasingly overlap in the same geography. Texas and New Mexico sit atop some of the nation's most productive hydrocarbon basins, especially the Permian Basin, while also facing recurring drought, rapid population growth, industrial demand, and ongoing concern over freshwater availability.

In the Southwest, produced water has shifted from a water-management challenge to a potential supplemental water resource. Producers have not attempted to alleviate water shortages solely through regulatory compliance; many have also invested in water recycling systems, water-sharing arrangements, expanded pipeline networks, and basin-scale planning intended to reduce freshwater withdrawals from underground aquifers and improve operational efficiency.

In the Permian Basin in particular, recycling water produced from oil and gas drilling for use in completion activities has become an increasingly important part of water-management strategy, reflecting both economic incentives and growing emphasis on conservation of limited freshwater supplies.

This shift is not merely conceptual. Produced water is already the largest waste-management stream associated with oil and gas production, and the volumes are substantial in major producing basins. At the same time, regulators, researchers, and operators are exploring whether at least some produced water can be treated, reused, or mined for valuable constituents such as lithium and other critical minerals.

The federal government has signaled support for reuse and recycling where legally and technically feasible, while state governments in the Southwest, particularly Texas and New Mexico, have become central forums for policy development, pilot projects, and litigation over ownership and reuse.

Complicating these efforts, the composition of produced water varies from basin to basin and even between wells within the same basin. Depending on the formation and production history, produced water may contain high salinity, residual hydrocarbons, heavy metals, naturally occurring radioactive materials, and chemical additives from drilling and stimulation operations. Those characteristics make treatment expensive, energy-intensive, and highly site-specific.

As a result, the question of what to do with produced water sits at the intersection of water scarcity, environmental protection, energy economics, property rights, and emerging technology.

For the Southwest, and especially Texas, the question is no longer whether produced water has value. It is whether these substantial volumes of fluid can be transformed into a practical asset while satisfying regulatory, technical, and stakeholder-confidence requirements.

What Is Produced Water?

Produced water is a byproduct of oil and gas production and consists of fluids that return to the surface as a result of drilling activity, generally including naturally occurring formation water, injected water, and chemicals used in drilling, completion, production, or maintenance operations.

In hydraulically fractured wells, some returned fluid may also be characterized as flowback water. In practice, however, these streams are often managed together as part of the broader produced-water management challenge.

Produced water is chemically complex and highly variable. Its composition depends on reservoir geology, field age, extraction methods, and operational inputs. Produced water may contain dissolved and dispersed hydrocarbons, salts, suspended solids, heavy metals, radionuclides, bacteria, dissolved gases, and residual treatment chemicals.

Salinity can range from relatively low levels in some western fields to concentrations far above seawater in formations such as the Marcellus and Bakken, and much of the produced water in the Permian Basin is highly saline and operationally difficult to treat.

The sheer volume of produced water generated by oil and gas operations is one reason it has become such a significant policy issue. A 2023 review in *Water* reported that the oil and gas industry generates roughly 250 million barrels of produced water per day globally, making it the industry's principal byproduct stream by volume.

In the United States, produced water generation has risen alongside the growth of unconventional oil and gas production, and Texas consistently ranks among the leading producer states by volume, with the Permian Basin and Texas oilfields generating more produced water than all other U.S. oilfields combined. According to reports from Texas A&M, Texas and Permian Basin oilfields generate between 22 million and 33 million barrels—or approximately 1 billion gallons—of produced water daily.

The Permian Basin is especially important in any water-management discussion. Data from the Department of Energy's Office of Fossil Energy and Carbon Management shows that the Permian Basin accounts for roughly half of U.S. oil production and an outsized share of produced water generation, producing more water than all other U.S. shale plays combined.

That juxtaposition makes clear why Texas, and particularly the Permian Basin, dominate discussions surrounding saltwater disposal capacity, water recycling, and beneficial reuse.

Produced water has historically been treated as an oil-and-gas management byproduct rather than conventional groundwater or a ready substitute for municipal supply. But because it is generated in such immense volumes in water-stressed regions, it has become increasingly difficult to view solely as a disposal issue.

Ground Zero for Discussion: The Arid Southwest

The case for treating produced water as a strategic resource is strongest in the water-scarce Southwest. The region faces overlapping pressures from drought, rising temperatures, population growth, agricultural demand, industrial expansion, and ecological stress.

A 2025 U.S. Geological Survey National Water Availability Assessment found that nearly 30 million people live in areas where available surface-water supplies are limited relative to water use. Corpus Christi is currently on pace to exhaust its water reserves before 2028.

In the Southwest, aridity is structural rather than episodic, and the pressure to address water scarcity is significant. State leaders and industry participants have increasingly looked at produced water as a possible "new water" source because traditional freshwater supplies are under strain and many of the most productive oil basins are located in arid parts of West Texas.

Texas policymakers are actively examining whether oilfield wastewater could help address looming water shortages, although the treatment and energy requirements remain substantial.

At the same time, oil and gas extraction itself is water-intensive, despite producers' efforts to reduce freshwater consumption. Hydraulic fracturing in major shale basins requires significant water volumes, often in semi-arid areas where water resources are already constrained.

Produced water therefore occupies a dual role in Southwest water policy: it is both a consequence of water-intensive energy production and a possible partial offset to freshwater demand if it can be safely reused.

This dual role is especially visible in the Permian Basin, which produces extraordinary volumes of water well beyond what can currently be reused in completion activities alone. Even where operators have significantly increased recycling for hydraulic fracturing, substantial volumes still require transport, treatment, or underground injection.

In the Southwest, then, the appeal of produced water is relatively straightforward: it is one of the few massive water streams already being brought to the surface in places where freshwater is scarce. The challenge is that converting it into usable water requires overcoming significant technical, legal, and economic barriers.

Key Takeaway

Produced water is no longer viewed solely as an operational byproduct. In the Southwest, it has become part of a broader conversation surrounding water security, infrastructure, environmental management, and resource development.

Still, significant questions remain unresolved. Treatment costs, infrastructure requirements, environmental concerns, and public confidence continue to complicate broader reuse efforts.

This article is Part 1 of a 3 Part series from FBT Gibbons. Part 2 will be featured in the October 2026 issue of the ELA; Part 3 will be featured in the December 2026 issue of the ELA.

Measuring What Matters: How MRC Permian Reshapes Retained-Acreage Disputes in Horizontal Drilling

J. McLean Bell, McGinnis Lochridge

Unconventional drilling changed the economics of oil and gas development. It also changed the leases. Where once a simple habendum clause and a shut-in royalty provision could govern a vertical well for decades, horizontal drilling introduced a new vocabulary, and with it, new disputes. The Eighth Court of Appeals' December 2025 decision in *MRC Permian Co. v. Point Energy Partners Permian LLC* ("*MRC Permian*") tackles one of these disputes head-on: how do you measure the lateral length of a horizontal wellbore?

The Dispute

MRC leased roughly 4,000 acres in Loving County under four identical leases. The leases required continuous drilling after the three-year primary term: spud a new well within 180 days of the prior well or lose everything outside designated production units. MRC drilled five horizontal wells during the primary term, missed the deadline to spud a sixth, and claimed force majeure. The Texas Supreme Court rejected that defense in 2023 and held the lease terminated in May 2017 as to all acreage outside production units.

That left the retained-acreage question. The lease allowed MRC to designate one production unit per well, sized according to a seemingly straightforward formula: up to 160 acres (plus 10% tolerance) if less than 5,000 feet of the wellbore extended horizontally in the producing formation, and up to 320 acres (plus 10% tolerance) if more than 5,000 feet did. MRC claimed the larger units. Point Energy said the wellbores fell short of the 5,000-foot threshold.

How the Court Measured the Lateral

Point Energy advanced a two-part measurement method. First, it argued the court should only count the "producing" segments of the wellbore—the intervals between perforations, or "take points," where oil was actually being extracted. Second, it argued the wellbore should only be measured where it was "reasonably horizontal," meaning inclined at roughly 75 to 85 degrees from vertical. Under this approach, the wellbores came in under 5,000 feet.

MRC countered with a simpler method: measure from the point where the wellbore first enters the producing formation—after it has kicked off from vertical—to the terminus. Under this approach, both the Totum #211H and Jackson Trust #121H wells cleared the 5,000-foot threshold.

The Eighth Court sided with MRC on both fronts.

On the "producing segments" argument, the court found the lease language dispositive. The clause required that "the wellbore extends horizontally in the producing formation." It said nothing about the wellbore producing at every point along its length. The court drew a clean distinction: "producing formation" is a geological term—it describes the rock stratum from which hydrocarbons are obtained, not the specific intervals where perforations happen to be placed. The lease described *where* the wellbore is, not *what* the wellbore is doing.

On the "horizontal angle" argument, the court refused to graft a numerical angle requirement onto lease language that contained none. Point Energy wanted "horizontally" to mean roughly 90 degrees from vertical. The court acknowledged that horizontal wellbores are never perfectly horizontal—they curve, they navigate subsurface geology, they follow the formation. Imposing an angle threshold would ignore how horizontal drilling actually works.

The court offered a memorable analogy. Measuring the distance a car travels "east" on Interstate 10 means the distance along the highway as measured by mile markers—not the straight-line distance due east from start to finish, and not the distance after subtracting stretches where the highway veers north around San Antonio. Wellbores, like highways, navigate terrain. The lease measured the journey, not the bearing.

The result: measurement begins at the point where the wellbore enters the producing formation after deviating from vertical, regardless of angle, and extends to the terminus. MRC retained two 352-acre production units—704 acres total.

Two Ancillary Holdings Worth Noting

The court also addressed MRC's failure to file production-unit designations within the 90-day window required by the lease. Point Energy argued this failure was a special limitation that capped MRC's units at 160 acres. The court disagreed. Because the lease contained no language stating it would "automatically terminate" upon failure to designate, the filing requirement was a covenant—a breach of which sounds in damages, not forfeiture. This holding is consistent with the plethora of Texas jurisprudence disfavoring forfeiture and requiring special limitations on title to be stated clearly, precisely, and unequivocally.

On quasi-estoppel, the court held that MRC's continued payment of royalties—roughly $900,000—did not estop Point Energy from claiming the lease terminated. MRC paid with full knowledge of the dispute. The lessors accepted with explicit reservation-of-rights letters. No unconscionability—no estoppel.

The Limits of This Holding—and Why Lease Language Is Everything

The court's analysis turned on the specific language of this lease. The clause measured how far the "wellbore extends horizontally in the producing formation." That phrase anchored the court's reasoning—the formation is a geological stratum, and the wellbore either extends through it, or it does not. For leases that contain similar language, the method the court used to measure the lateral is instructive. This methodology could also be instructive in the absence of a stratum limitation, but it would of course depend on the lease and the facts of the case.

Many horizontal wells traverse multiple formations on their path from heel-to-toe—sometimes intentionally, to reach a target zone, and sometimes because subsurface geology does not cooperate with the drill plan. A lease that ties horizontal measurement to a specific formation will likely produce a different result than one that is silent. For example, in a depth severed lease, should portions of the lateral that exit the stratum be measured? The *MRC Permian* court did not address many of the potential ways a lease's language could inform a horizontal measurement, but unconventional drilling makes these kinds of questions ripe for future litigation.

Practical Takeaways for Drafting

The lesson from *MRC Permian* is that imprecise language concerning horizontal length requirements may result in unintended results. However, the case reinforces the principle that conditions need to be extremely clear; otherwise, a court will hold they are covenants. Thus, if a landowner desires a horizontal to be drilled and/or measured in a specific way, precise language is required. If a landowner wants the horizontal requirement to be more than a covenant, explicit conditional and/or forfeiture language is required.

A few drafting principles can reduce ambiguity.

For operators and their counsel: Define the lateral length as measured depth from the heel to the toe—or, better yet, tie the measurement to the W-2 or completion report filed with the Railroad Commission. Commission records are public, verifiable, and remove subjectivity from the equation. Avoid language that invites disputes about angles, producing intervals, or formation boundaries. The simpler the measuring stick, the fewer arguments about the result.

For landowners and their counsel: Consider specifying that only the perforated or completed interval counts toward the lateral-length threshold. If the goal is to tie larger acreage to greater productive capacity—and for most lessors, it is—then the lease should say so explicitly. Require that the measurement reflect the spacing between the first and last perforation clusters or limit the measurement to perforations within a specified formation. Language like "the completed lateral length as measured between the first and last perforation stages" removes the ambiguity that Point Energy exploited.

Disputes concerning the measurement of horizontal wells are not going away. Leases and JOAs are increasingly requiring operators to drill horizontal wells with minimum lateral requirements. As the wells get longer and the laterals become more complex, courts will continue to construe whatever language the parties give them. *MRC Permian* is a reminder that the time to resolve ambiguity is at the drafting table—not in the courtroom.

IEL International Practice Committee Update

Below is an update on recent developments in the oil and gas sector in Africa and Central and South America submitted on behalf of the IEL International Practice Committee.

Angola: Organizational Statute of ANPG Amended

Luís Miranda, Miranda Alliance

As part of efforts to reform its operational framework and enhance technical efficiency, the amendment to the Organizational Statute of the National Oil, Gas and Biofuels Agency (*Agência Nacional de Petróleo, Gás e Biocombustíveis* - "ANPG") was enacted by Presidential Decree No. 73/26, of 22 April 2026. The revisions address the agency's mandate, organizational structure, governing bodies, and respective powers, marking an institutional repositioning aimed at improving efficiency and operational agility. This statute became effective upon publication.

Brazil: Brazil Regulates Third-Party Access to LNG Terminals: ANP Resolution No.1 1,003/2026

Alis Hage and Livia Amorim, Veirano Advogados

On July 2, 2026, Brazil's National Petroleum, Natural Gas and Biofuels Agency (ANP) published Resolution No. 1,003/2026, which regulates negotiated third-party access to Liquefied Natural Gas (LNG) terminals introduced by Article 28 of Law No. 14,134/2021 (the "Gas Law"). The Resolution applies exclusively to LNG terminals, leaving access rules for production outflow pipelines and Natural Gas Processing Units to a separate rulemaking under ANP's Regulatory Agenda.

Brazil currently operates eight LNG regasification terminals along its coastline. Most were originally built to serve dedicated anchor demand—primarily thermoelectric generation—and none have yet effectively functioned as multi-user facilities. The Gas Law classified LNG terminals as "essential infrastructure" subject to mandatory sharing, departing from the prior regime under Law No. 11,909/2009, which did not require third-party access. *See* Lei No. 14,134, de 8 de abril de 2021, art. 28 (Braz.).

The Resolution establishes four core capacity concepts: operational capacity, contracted capacity, available capacity, and idle capacity. Operators must grant access to interested third parties whenever available or idle capacity exists, on objective, transparent, and non-discriminatory terms. Contracts are limited to a maximum term of fifteen years. The regulation also introduces a preferential right for the terminal owner, initially set at total operational capacity for the first ten years and subject to downward-only reviews every five years thereafter.

To ensure transparency, operators must prepare and submit a Code of Conduct and Access Practice (CCPA) for ANP approval by September 30, 2026. The CCPA defines access terms, compensation guidelines, and mechanisms to prevent capacity retention and contractual congestion. Notably, any indication of a violation of the economic order triggers immediate referral to Brazil's antitrust authority, CADE.

The Resolution also mandates interconnection between LNG terminals and transmission pipelines, requiring operators to permit third-party investments for connection unless technical risks to safety or integrity are demonstrated. Vertically integrated operators must maintain accounting separation to prevent cross-subsidies and competitive distortion.

From a market perspective, the regulation seeks to balance fair access against what may be characterized as "free-rider" behavior—whereby agents rely on existing infrastructure rather than investing in new capacity. The challenge remains significant given the operational flexibility demanded by Brazil's thermoelectric dispatch model, where gas demand is inherently variable and unpredictable.

Resolution No. 1,003/2026 seeks to place Brazil within an international trend in LNG market liberalization, signaling opportunities for producers, traders, and new entrants seeking terminal capacity. However, market participants should monitor further regulatory developments, including developments in respect of the preservation of current terminal owners' rights and ANP's forthcoming rules on access dispute resolution.

<u>Colombia</u>: Arbitration Award Denying Force Majeure in Gas Sales Agreement: Evidentiary Standards and Operational Risk Allocation

Jose Plata Puyana, Serrano Martínez CMA

In April 2026, the District Court of Bogotá denied an appeal against a domestic arbitration award that addressed a critical question for natural gas sales agreements: whether an unusual influx of water in production wells constitutes force majeure or an inherent operational risk. The Arbitration Tribunal ruled that such water influx was an operational risk inherent to the activity and not a force majeure event. The dispute arose from a breach of a gas sales agreement between CNE Oil & Gas / CNEOG Colombia ("CANACOL" or "Respondent"), a natural gas producer, and VP INGENERGIA ("Claimant"), a retailing company. As a consequence, the Arbitration Tribunal estimated damages up to USD $40 million.

The Respondent argued that a chain of extraordinary circumstances in the second half of 2023 prevented it from fulfilling its supply obligations. Specifically, CANACOL claimed that an unusual influx of water—exceeding expected reservoir levels—significantly reduced production in several wells. *See* Arbitration Tribunal Award at 74. The Respondent attributed this phenomenon to a high intensity seismotectonic event that occurred approximately 200 kilometers from the production wells, which allegedly triggered the anomalous water intrusion. *See id.* at 88. Conversely, the Claimant contended that these circumstances constituted predictable and resistible operational risks typical of a diligent natural gas producer. *See id.* at 78. The Claimant further emphasized the absence of any demonstrable correlation between the water influx and the seismic event. *See id.* at 100, 164.

After reviewing the expert reports filed by both parties, the Arbitration Tribunal concluded that the Respondent failed to discharge its burden of proving the specific cause of the water influx. The Tribunal found that the Respondent's claims were "limited to describing an 'unusual and unexpected' influx and generically invoking 'seismotectonic events,' without tracer studies, hydrodynamic modeling, seismic-production correlation, or well integrity analyses to establish a causal link." *Id.* at 100. The Tribunal explains that "water influx is a phenomenon inherent to gas exploitation, the occurrence of which depends, among other factors, on drawdown management, reservoir conditions, and artificial lift practices". *Id.* at 109.

Additionally, the Arbitration Tribunal questioned the methodology used by the expert report that resorted to "academic articles analyzing similar phenomena that occurred in other regions of the world and extrapolates their conclusions to what, hypothetically, could have happened in the gas fields operated by the Respondent". *Id.* at 100, 113. The expert report includes alternative and more probable hypothesis, yet it fails to establish a causal link between any alleged extraordinary event and the unusual water influx. *See id.* at 109.

This evidentiary deficiency proved insufficient to the force majeure defense, as the Arbitration Tribunal emphasized that technical causation must be demonstrated through rigorous scientific methodology, not merely descriptive assertions.

This award underscores that force majeure cannot be invoked generically. The burden of proof to exempt liability under a breach of contract claim requires specific, technical demonstration of causation. Inherent business risks—including operational uncertainties in hydrocarbon production—cannot serve as liability exemption events absent compelling evidence of extraordinary and unforeseeable circumstances. For practitioners, this decision signals that natural gas producers must maintain robust technical documentation and monitoring systems capable of substantiating any future force majeure claims with scientific rigor.

<u>Chile</u>: Integrating Energy Storage into the Regulatory Framework for Small Scale Generation Facilities

Mónica Cortés, Fernanda Skewes, and Massiel Castañeda, FerradaNehme

In Chile, the regime governing Small Distributed Generation Facilities (PMGD, by its Spanish acronym) has been instrumental in the development of renewable energy. However, although these facilities inject a significant volume of energy simultaneously during daytime hours, they make no contribution to the system at night. To address this shortcoming, to bring order to this growth, and to render operational the incorporation of batteries, originally promoted by Law No. 21.505, published in November 2022, the Ministry of Energy published Decree No. 1 on June 13, 2026, which amends Supreme Decree No. 88 of 2019. *See* Ministerio de Energía. (13 de junio de 2026). Decreto 1. Three principal changes may be identified.

First, the decree creates the regulatory category of "small scale generation facilities and storage systems" (MGPE, by its Spanish acronym), expressly recognizing battery energy storage systems (BESS) with surplus capacity of 9,000 kW (9 MW) or less as entities entitled to the prerogatives associated with connection to distribution networks (PMGD) or transmission networks (PMG). This provides certainty as to the legal characterization of this type of storage system, a matter of particular relevance for the financing of such projects.

Second, under the new Article 9 bis, the energy that a battery withdraws from the grid in order to recharge will be valued under the same pricing regime that the project has elected for the sale of its injections, whether at marginal cost or at the stabilized price, thereby affording investors greater certainty regarding their operating margins. In addition, Article 9 ter expressly exempts such withdrawals from the payment of tolls and charges applicable to end customers and, since battery charging is not treated as final consumption, it overcomes its principal barrier to profitability. *Id.* art. 9 ter. In any event, Article 29 bis requires metering systems capable of distinguishing the energy destined for the battery from the project's own consumption, thereby preventing the double counting of injections and withdrawals. *Id.* art. 29 bis.

Third, a Basic Energy Price differentiated by time interval has been established, a mechanism that allows for differentiated remuneration according to the time of day. *Id.* art. 14. In other words, it incentivizes storage systems to absorb energy during the hours of peak solar radiation and to inject it during the nighttime hours of highest demand.

Although Decree No. 1 enters into force on July 13, 2026, the market impact generated by regulatory expectations has already been evident. According to recent data, interest in integrating batteries has grown exponentially: in the first half of 2026 alone, 17 PMGD projects with storage systems entered the connection process, amounting to 141.85 MW, a remarkable increase compared to the 6 projects registered throughout 2025. *See* Coordinador Eléctrico Nacional, PMGD Report: April–June 2026, at 4 (2026). Indeed, between April and June 2026, photovoltaic technology combined with batteries dominated new connection applications, *id.* at 3, with results already materializing through the commencement of operations of the PSF BESS Lota II project in June. *Id.* at 5.

Mexico: From Policy Design to Transaction Execution: Mexico's Mixed Investment Power Projects Face the Bankability Test

Erika Roldán and Alejandro Guzmán, Goodrich, Riquelme y Asociados

Mexico is not eliminating private generation, nor is it returning to a fully liberalized merchant model. The new framework instead adds a distinct state-led track for private capital through CFE-centered mixed investment projects. Private generators may continue to participate in the wholesale electricity market under applicable rules, but the mixed investment program responds to a separate policy objective: ensuring that the State, through CFE, retains a leading role in national generation while incorporating private capital and technical capacity into projects aligned with public planning. Over the past year, that policy design has begun to move from statutory reform and planning instruments into concrete project structures.

That shift has been operationalized through a defined mixed investment funnel. After the enactment of the new legal framework, the government issued implementing regulations and planning instruments, including PLADESE and PROSENER, identifying capacity, technology, and regional needs across the National Electric System. CFE then issued internal Mixed Development Guidelines establishing governance rules, financial profitability criteria, and selection procedures. This sequence culminated in a February 2026 public call for 6,500 MW of renewable capacity. While initial reports in March highlighted a massive market response (with 37,749 MW registered, representing 581% of the requested capacity) the actual selection process proved highly restrictive. Preliminary results reported in June indicated that the pipeline was heavily filtered down to 37 awarded projects totaling approximately 7,411 MW, equivalent to 114% of the initial target. Industry participants noted that more than half of the advancing proposals were ultimately discarded during negotiations due to transmission grid congestion, unmet environmental requirements, or uncompetitive pricing.

The model is now beginning to move from these narrowed awards into contractual documentation. Translating selected projects into financeable assets requires more than a headline award; it requires a coordinated legal package built around mixed investment agreements, trust structures, long-term power purchase arrangements, and project documents. As one illustration of this early crystallization, Polaris Renewable Energy reported that, on July 3, 2026, it executed a Mixed Investment Agreement with CFE's fiduciary trustee for three solar photovoltaic projects with battery energy storage systems, representing approximately 250 MWdc of generation capacity. That example is notable not because of the sponsor itself, but because it shows the mixed investment model beginning to operate through binding project documentation.

Bankability remains the test. The first round indicates that private appetite exists for CFE-centered structures, but the next question is whether these projects can reach financial close and construction. Lenders and investors will focus on whether the trust agreement, PPA, EPC, O&M, and financing arrangements operate as a coherent risk-allocation package. Key issues include governance within the Technical Committee, CFE's offtake and payment obligations, interconnection and system upgrade costs, step-in rights, valuation of non-cash contributions, and the methodology for calculating the target internal rate of return and any eventual transfer of economic rights. If those mechanisms withstand lender diligence, Mexico's mixed investment model may move beyond legal architecture and become an executable infrastructure platform.

MEMBER NEWS

The Institute for Energy Law is pleased to announce its 2026-27 Leadership Class. Now in its ninth year, the program brings together 40 professionals. This year's class reflects the breadth of today's energy landscape—professionals from eight U.S. states, Washington, D.C., Mexico, Switzerland, and Venezuela, working across litigation, transactions, regulatory matters, arbitration, engineering, and energy law. Beyond their careers, members bring remarkable personal stories: former collegiate athletes, multilingual professionals, first-generation lawyers, published authors, musicians, entrepreneurs, mentors, and parents—perspectives shaped by countries, industries, and career paths as varied as the class itself. The full list of 2026-27 Leadership Class members can be found on our website here.

UPCOMING IEL PROGRAMS

Two upcoming August webinars are free for IEL Members: "Venezuelan Roadmap: How to Participate in the Upstream Oil and Gas Sector," hosted by the IEL International Practice Committee, August 14 from 10:00-11:00 AM Central; and "MSA Terms and (Re-)Emerging Trends in Oilfield Services Contracting," hosted by IEL's Oilfield and Energy Services Practice Committee, August 25 from 12:00-1:00 PM Central. MCLE credit is available for both webinars.

Registration is now open for our Fall 2026 Programs: 17th Appalachia Energy Law Conference, September 10 at the Fairmont in Pittsburgh, PA (register before August 17 to take advantage of early bird pricing); IEL Upstream Operational Issues and M&A Trends Conference, October 7 in Houston, TX; and the 25th Annual Energy Litigation Conference, November 10 in Houston, TX. Check out our Programs Calendar for registration and more information about upcoming events.

NEW MEMBERS

We are honored and excited to add the following companies and individuals to IEL's membership roster. Please join us in welcoming them to our organization!

ASSOCIATE MEMBERS

- **Matthijs Nieuwveld,** Chevron, Houston, TX
- **James Parrot,** Beatty & Wozniak, P.C., Denver, CO
- **Mary T. Sott,** Hightowers Petroleum Co., Middletown, OH
- **Enrique Segura,** Segura Abogados, Santo Domingo, Dominican Republic

YOUNG ENERGY PROFESSIONAL MEMBERS

- **Rosario Galardi,** Vinson & Elkins LLP, Washington, D.C.
- **Francesca Iovino,** Babst Calland, Pittsburgh, PA
- **Libby Pegg,** Baker Botts L.L.P., Houston, TX
- **Chelsea Teague,** Exxon Mobil Corporation, Spring, TX

FULL-TIME LAW STUDENTS

- **Adetoun Ojo,** American University Washington College of Law, Aurora, CO
- **Zahra Pakyari,** Texas A&M University School of Law, Irving, TX

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JULY 2026

VOL. 20 | NO. 2

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