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Louisiana Department Reorganized and Given New Name; Office of Conservation Eliminated

Keith B. Hall
LSU Law Center

Louisiana Acts 2025, No. 458 changes the name of the Department of Energy and Natural Resources (DENR), until last year known as the "Department of Natural Resources," to the "Department of Conservation and Energy."[1] The change was effective October 1, 2025. The Department is now sometimes being called "C&E."

In addition, the legislation eliminates the Office of Conservation. The Office of Conservation used to be the Department of Conservation, but since the mid-1970s it has been a semi-independent subpart of the Department of Natural Resources and then the Department of Energy and Natural Resources. The position of "Commissioner of Conservation" is being eliminated.

The Department previously consisted of four main divisions—the Office of the Secretary, which included administrative personnel and the State Energy Office; the Office of Conservation, led by a Commissioner of Conservation (who was largely independent of the Secretary of the Department), with responsibilities that included regulation of oil and gas activities, pipelines, mining, and injection wells; the Office of Coastal Management; and the Office of Mineral Resources, which acted for the State of Louisiana and some local governments in matters relating to leasing of state mineral and energy resources.

After the reorganization, the Department has six divisions: the Office of the Secretary, which will handle "strategic management" of the Department, legal matters, and Oilfield Site Restoration; an Office of Administration, which will handle administrative matters, including human resources and budgetary matters; an Office of Permitting and Compliance, which will handle permitting; an Office of Enforcement, which will conduct site inspections and enforce both state rules and federal rules for which Louisiana has primacy; an Office of State Resources, which will oversee leasing of state resources, and an Office of Energy, which will seek to promote Louisiana's development of reliable and resilient energy systems.[2]

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[1] A copy of Act 458, which originated as Senate Bill No. 244, is available at https://legis.la.gov/legis/ViewDocument.aspx?d=1426071. The Act is 227 pages long. One of the reasons the Act is so long is that it attempts to amend all of Louisiana's statutory references to the former Department of Energy and Natural Resources to reflect the new name. Also, the Act contains substantive provisions relating to the reorganization of the Department. Also, Act 458 contains some provisions that amend Louisiana's statute governing procedures for legacy litigation (oilfield contamination litigation).
[2] A press release describing the reorganization is available on the Department's website at https://www.dce.louisiana.gov/news/denr-to-become-ce.

Louisiana Grants First UIC Class VI Permit for CCS

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On September 5, 2025, the Louisiana Department of Energy and Natural Resources (now the Department of Conservation and Energy) granted a UIC Class VI permit to Hackberry Carbon Sequestration, LLC, whose offices are in Houston, Texas, for the Hackberry Sequestration project in Cameron Parish, Louisiana. The order granting the permit, along with extensive supporting information, is available on the website of the Louisiana Department of Conservation and Energy.[1]

Hackberry submitted its application on February 5, 2024. The application was considered administratively complete on March 15, 2024, and technically complete on March 25, 2025. Hackberry states that it plans to inject CO_2 in its injection well for twenty years and that it plans to inject up to an estimated 2 million metric tons per year. The injection zone is between 4,022 and 10,026 total vertical depth. The planned injection stream is stated to have a composition of 98.3% carbon dioxide, 1.6% methane, and 0.1% other compounds. This stream will be compressed to nearly 3,000 psi pressure at the surface, prior to injection.

The Hackberry project will be used to sequester carbon dioxide captured from Cameron LNG's natural gas liquefaction facility.[2] The Cameron LNG facility is owned by Sempra Infrastructure.[3]

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[1] The permit is available at https://sonlite.dnr.state.la.us/dnrservices/redirectUrl.jsp?dDocname=15334548&showInline=True.
The permit and the "well file" documentation is available at https://sonlite.dnr.state.la.us/dnrservices/redirectUrl.jsp?dDocname=15339755&showInline=True.
A list of all pending applications for Class VI permits, along with links to well files, is available at https://www.denr.louisiana.gov/page/permits-and-applications.

[2] This is reported at a website for the project, which is available at https://semprainfrastructure.com/what-we-do/low-carbon-solutions/hackberry-carbon-sequestration/.

[3] *See* "About Sempra – What We Do: LNG," available at https://semprainfrastructure.com/what-we-do/lng/. Sempra's general website is available at https://www.sempra.com/.

Louisiana Governor Imposes Moratorium on Review of New Class VI Permits for CCS

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On October 15, 2025, Louisiana Governor Jeff Landry directed the Department of Conservation and Energy to suspend the review of any applications for Class VI permits to construct and operate Class VI injection wells for CCS.[1] Referencing the "volume of applications received," the Governor directed the Department, "over the next forty-five days," to "reevaluate the status of applications for assessments and prioritization". Governor Landry's order also referred to guidance issued on September 1, 2025, by Tyler Gray, who then was head of the Department.[2] That guidance refers to certain pending Class VI permit applications that will receive priority by the Department in its consideration of applications. These include: (1) Capio Sherburne CCS Well #1 in Pointe Coupee Parish; (2) CCS 2 – Wilcox in Vernon Parish; (3) Goose Lake and Minerva South in Calcasieu and Cameron Parishes; (4) LGF Columbia in Caldwell Parish; and (5) River Parish Sequestration – RPN 1 in Ascension Parish.[3]

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[1] A copy of the order is available at: https://www.denr.louisiana.gov/assets/OC/ClassVI/Overview/Department-Directive-Order-No-B-2025-01-combined.pdf.

[2] Since then, Tyler Gray has left the Department. He is now director of the Energy Innovation portion of the newly-created LSU Energy Institute. The current Secretary of the Louisiana Department of Conservation and Energy is Dustin Davidson, who previously served as Undersecretary.

[3] Copies of the guidance and certain related guidance documents are attached to the Governor's order.

Virginia Appeals Court Provides Guidance for Gas Companies on Pipeline Zoning Exemptions

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On July 1, 2025, the Court of Appeals of Virginia ruled that a natural gas company's proposed pipeline project was exempt from a requirement to obtain a special exception under the local zoning ordinance. The court's ruling in *Zinner v. Washington Gas Light Co.* provides insights for natural gas companies navigating local zoning ordinances when proposing to install pipelines in communities.

The case stemmed from a natural gas company's proposal to build a pipeline under a neighborhood road in Fairfax County without a special exception from the Board of Supervisors. The zoning administrator determined that the proposed pipeline was a "distribution" line exempt from special exception requirements under the local ordinance and not a "transmission" line requiring a special exception.

Four landowners appealed the determination. The Board of Zoning Appeals (BZA) reversed, agreeing with the landowners that the project was for a transmission line requiring an exception. The circuit court reversed the BZA, and both parties appealed.

Though not controlling under the text of the local ordinance, the Court of Appeals considered the four federal criteria for a "transmission line" found in 49 C.F.R. § 192.3 and concluded that the proposed project failed to qualify as a transmission line under the federal regulatory definition and the local ordinance.

The court highlighted key evidence supporting its conclusion that the project was an ordinary distribution line: (1) the company delivers gas to consumers and does not produce or resell it; (2) the company obtains the gas it delivers from supplier pipelines at a "city gate" rather than transporting it from a storage facility; and (3) while the company uses different pressure systems to deliver gas to consumers, the company only uses low-pressure lines to connect to customers' homes.

Notably, the Court of Appeals' decision reviewed the BZA's legal conclusions *de novo* and held that the BZA erred in concluding that distribution lines are limited to low-pressure lines connecting directly to customers' homes, as that requirement did not appear in the ordinance. The court limited its holding to the project at issue, as opposed to ruling that the company's entire pipeline system was exempt from the special exception requirement. It also dismissed the gas company's separate appeal, which sought a declaratory judgment barring the zoning ordinance at issue under state law, as moot.

The court's opinion provides useful insights regarding the type of evidence zoning administrators, BZAs and courts may look to when distinguishing between “distribution” lines and “transmission” lines, or when assessing other special exception requirements, for future pipeline projects. Natural gas companies operating under a FERC certificate should also consider whether preemption is available to avoid the need for such exceptions.

Indiana Court Applies Rule of Capture in Coal Mine Methane Dispute

Keith Hall
LSU Law Center

In *Pioneer Oil Co., Inc. v. ECC Bethany, Inc.*, 2025 WL 2858581 (Ct. App. Ind. 2025), an oil and gas lessee asserted a trespass claim against an operator that had rights on neighboring property, but courts in Indiana rejected the claim, applying the rule of capture and holding that a trespass claim did not exist in the absence of a physical intrusion into the surface or subsurface of the land where the plaintiff held rights.

Background

Heidenreich Farms, Inc. ("Heidenreich") owned the surface and mineral rights for each of two adjacent tracts. In the past, Gibson County Coal, LLC ("GCC"), operated a coal mine beneath one of the tracts. GCC constructed a tunnel called the "Slope," which went upward from the mine to the surface at a diagonal, rather than straight vertically. Although the bottom of Slope started at the mine, beneath one of the two tracts, the Slope entered the subsurface of the other tract before the Slope reached the surface. The Slope was used to transport materials to and from the mine. GCC operated the mine until 2019, when all the commercially recoverable coal was exhausted. In 2020, GCC sealed the coal mine and the Slope.

In 2022, Heidenreich, as surface owner and mineral owner, granted an oil and gas lease to Pioneer Oil Co., which drills and operates wells to recover methane from voids left by coal mines (methane exists naturally in coal seams). The oil and gas lease to Pioneer covered the tract (the "Pioneer Leasehold Parcel") whose subsurface contained the coal mine. A few weeks later, Heidenreich granted a lease to GCC for the neighboring tract (the "GCC Leasehold Parcel"), authorizing GCC to drill and extract methane.

GCC did not drill a well, but GCC contracted with ECC Bethany, Inc. to conduct operations to recover methane. Working through ECC, GCC unsealed the Slope and installed equipment to extract methane. All the physical operations conducted by GCC were beneath the GCC Leasehold Parcel. GCC did not conduct any operations beneath the Pioneer Leasehold Parcel to recover methane. However, the methane extracted by GCC's operations would originate from the location of the abandoned mine, beneath the Pioneer Leasehold Parcel.

Pioneer filed suit, alleging a trespass and conversion. Pioneer argued that the Slope was the equivalent of a slant well that intruded into the subsurface of the Pioneer Leasehold Parcel, and that GCC's activities to recover methane therefore constituted a trespass. The trial court rejected Pioneer's arguments, dismissing Pioneer's case on the pleadings for failure to state a claim. Pioneer appealed.

The Indiana appellate court affirmed. The appellate court held that, for a plaintiff to plead a trespass, the plaintiff must allege a physical invasion of property. But Pioneer did not allege a physical intrusion by GCC. Therefore, Pioneer failed to state a claim for trespass. Further, Pioneer failed to state a claim for conversion. The appellate court noted that Indiana follows the rule of capture. Therefore, although the methane recovered by GCC may have originated from the subsurface of the Pioneer Leasehold Parcel, GCC would own whatever methane it could recover from operations conducted entirely on and beneath the neighboring GCC Leasehold Parcel where GCC held lease rights. Pioneer argued that the rule of capture did not apply when a defendant's operations violate a state's oil and gas regulations, but Pioneer had neither shown a regulatory violation by GCC nor cited Indiana legal authority that a violation of oil and gas regulations would negate the rule of capture.

Texas Lessor Not Entitled to Self-Help Burial of Pipelines

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In *Byrne Oil Co. v. Walraven*, 2025 WL 2617716 (Tex. App.—Eastland 2025), an oil and gas lessor repeatedly asked the lessee to bury pipelines, pursuant to a lease clause requiring the lessee to bury pipelines below plough depth when requested by the lessor. Eventually, the lessor—Walraven—threatened to move the pipelines himself. The lessee—Byrne Oil Co.—filed suit seeking an injunction to prevent the lessor from moving the pipelines. Walraven answered the suit and filed a counterclaim, seeking an injunction to require Byrne Oil to bury the pipelines. Apparently, no hearing for preliminary injunctive relief was ever held.

After the litigation had been pending for some time, Byrne Oil hired a contractor that buried about 10,000 feet of the approximately 11,000 feet of pipelines that Byrne had on the leased premises. Later, at a time when the lawsuit had been pending for about two years, Walraven hired a contractor that buried the remaining portion of the pipelines.

A trial was eventually held. The trial court held that Byrne Oil had breached the lease by failing to bury the pipelines after Walraven requested that they be buried. The trial court granted a $30,000 money judgment in favor of Walraven for costs associated with burying the pipelines that his contractor buried. The trial court also awarded attorney fees to Walraven. Byrne Oil appealed.

On appeal, Byrne Oil relied in part on a provision in the oil and gas lease that required the lessor to give the lessee notice and at least 60 days to cure any breach before filing suit for a breach of the lease. Byrne Oil argued that this provision prohibited self-help and limited Walraven to a judicial remedy. Citing the Texas Supreme Court, the appellate court held that this notice-and-cure clause does not restrict what remedies are available. Instead, it merely gives the lessee some protection against loss of the lease by requiring the lessor to give the lessee an opportunity to cure any alleged breach before the lessor files suit.

However, the appellate court held that Walraven was not entitled to exercise self-help. Walraven had argued that, because Byrne Oil had failed to bury the pipelines upon Walraven's request, as the lease required, the continued presence of the pipelines on the surface constituted a trespass. But the appellate court concluded that the continued presence was more akin to a nuisance that interfered with Walraven's use and enjoyment of his property. The appellate court noted that, because Byrne Oil had surface use rights under the lease, Walraven's possession of the property was not exclusive. Further, although Byrne Oil had breached the lease by not burying the pipelines after Walraven requested Byrne Oil do so, Byrne Oil was within its rights when it initially placed the pipelines on the surface.

The appellate court pointed to authority that self-help is not proper for the abatement of a nuisance when there is time to pursue judicial proceedings. Walraven did not show that there was no time to pursue judicial proceedings. Further, the fact that the parties' litigation had been pending for two years by the time Walraven hired a contractor to bury the pipelines suggested that there had been time to pursue judicial proceedings.

Finally, the appellate court noted that there were policy reasons to discourage self-help of the sort exercised by Walraven. A lessee is in a better position to bury pipelines associated with an oil and gas lease. A lessor's self-help burial of a pipeline could cause a release that causes environmental harm. Further, the lessor's burial of a pipeline might interfere with mineral production.

For these reasons, the appellate court concluded that Walraven had not had the right to bury the pipelines. Therefore, the appellate court reversed the trial court's $30,000 money judgment in favor of Walraven for costs associated with burying the pipeline. Further, the appellate court reversed the attorney fee award to Walraven. The appellate court noted that it had reversed Walraven's primary recovery—the $30,000 money judgment for pipeline removal costs—leaving in place only a $1,869.32 damages award in favor of Walraven that Byrne Oil did not appeal. Therefore, it also reversed the attorney fees award.

Texas Supreme Court Denies Review Effectively Upholding El Paso Court of Appeals Dismissing Claims for Mineral Right Trespass on Standing Grounds Yet Provides a Foundational Framework for Trespass to Mineral Rights Claims

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In *Ageron Energy, LLC v. ETC Texas Pipeline, Ltd.*, 2025 WL 3038997 (Tex. 2025) the Texas Supreme Court rejected Ageron Energy, LLC's ("Ageron") Petition for Review from the El Paso Court of Appeals decision finding that Ageron lacked standing to bring its claims for trespass to mineral rights due to ETC Texas Pipeline, Ltd ("ETC") operated H2S disposal wells.

In this litigation, Ageron brought claims against ETC for negligence, nuisance, and trespass based on the allegation that ETC's H2S disposal operations were damaging Ageron's equipment and preventing it from mining its minerals.[1] ETC sought dismissal of Ageron's claims based on the argument that Ageron lacked standing because the claims accrued to the prior surface estate owners and therefore the Court lacked subject matter jurisdiction.[2]

In 2007 Regency Field Services (ETC's predecessor in interest) received a permit to operate an H2S disposal well.[3] Regency Field Services later obtained a permit in 2012 allowing it to increase the injection volume in the H2S well based on an updated estimate that indicated the H2S plume would take thirty years to migrate 2,900 feet from the injection site.[4] Despite this updated estimate, beginning later in 2012 H2S was detected on the Quintanilla Ranch in a producing oil and gas well.[5] Subsequently that same year H2S was detected in a well on the Dickinson Ranch and H2S escaped to the surface killing several cows.[6] As a result of these events, both the Quintanilla Ranch and Dickinson Ranch sued Regency Field Services for the H2S related injuries they suffered.[7]

After the litigation relating to the 2012 H2S injuries, Action Energy obtained some of the mineral interests on the Dickinson Ranch in 2018 and 2019 (at the time of the original litigation, the mineral estate remained unsevered from the surface estate)

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[1] *See ETC Texas Pipeline, Ltd. v. Ageron Energy, LLC*, 697 S.W.3d 334, 337 (Tex. App. —El Paso 2023, pet. denied).
[2] *Id.*
[3] *Id.* at 338.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.*

and after assigning its leases to Ageron in 2020, Ageron began taking the steps to drill oil and gas wells on the Dickinson Ranch.[8]

ETC had informed Ageron of the H2S wells and the proximity to Ageron's proposed drilling operations and Ageron had taken some precautions to protect its equipment.[9] Despite these precautions, however, the H2S corroded and severed Ageron's drill pipe causing H2S vapor to spew and forcing Ageron to plug and abandon its well.[10]

The El Paso Court of Appeals concluded that Ageron lacked standing under the single action rule because its claims accrued prior to its purchase of the leaseholds when the leaseholds were undivided property of the Dickinson farm. Therefore, they accrued at the time of the prior injuries to the Dickinson Ranch.[11]

While the El Paso Court of Appeals opinion was issued back in December 2023, the Texas Supreme Court issued a denial of Ageron's Petition for Review on October 31, 2025.[12] A denial of a petition for review is often not noteworthy, the concurrence issued by Justice Busby and joined by Justice Devine provides an important discussion regarding the El Paso Court of Appeals ruling and conclusion on the accrual of a cause of action.

Justice Busby specifically addresses the prior Texas Supreme Court ruling in *Lightning Oil Co v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39 (Tex. 2017). As Justice Busby states, "[t]he majority opinion in the court of appeals undermines this important protection of mineral rights, holding that a lessee's suit can be barred by res judicata even if its claims for interference with subsurface development are not yet ripe and could not have been brought earlier. That holding—which would put lessees in an impossible position—is contrary to our cases."[13] In writing this concurrence, Justice Busby, while not disagreeing that a petition for review should not be granted, appears expressly concerned with the import of the El Paso Court of Appeals opinion in that it appears to lead to the conclusion that a mineral interest owner's claims may accrue before those claims are even ripe.[14] As Justice Busby points out this is contrary to established Texas precedent.

Of most import to a mineral interest owner's right is when an injury to that interest accrues, which is established in the *Lightning Oil* precedent. Justice Busby points out that both Ageron and ETC's positions on claim accrual are incorrect and

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[8] *Id.*
[9] *Id.* at 339.
[10] *Id.*
[11] *Id.* at 347.
[12] *See Ageron Energy, LLC*, 2025 WL 3038997.
[13] *Id.* at *1.
[14] *Id.*

the El Paso Court of Appeals was addressing a false dichotomy.[15] Rather, claim accrual for a trespass to a mineral interest or injury to a mineral interest occurs when

> "[a]n unauthorized interference with the place where the minerals are located constitutes a trespass as to the mineral estate only if the interference *infringes on the mineral lessee's* ***ability*** *to exercise its rights*" to "explore, obtain, produce, and possess the minerals subject to the lease." . . . "[S]peculation [about future interference] is not enough" to meet this standard, and "the mere fact that contaminants have migrated into the subsurface space covered by a mineral lease does not itself establish [injury]." . . . The various "triggering events" that bewildered the court of appeals . . . are simply types of evidence that could be offered in a particular case to show when (or whether) the migration infringed on the mineral lessee's development rights."[16]

Importantly, Justice Busby addresses that the existence of different property interests will often result in different conduct that may injure those property interests. In the present case, the injury to the livestock on the Dickinson Ranch in 2012 is not necessarily an injury to the mineral estate on the same property because those property rights are distinct.[17]

Justice Busby also addresses an important distinction regarding res judicata and nuisance claims, particularly where there may be a temporary or permanent nuisance. "As we have explained, the classification of a nuisance as permanent or temporary turns on 'whether an earlier recovery of damages is res judicata'—that is, 'whether one or a series of suits is required.'"[18]

Another important issue addressed in the concurrence is whether the El Paso Court of Appeals was even addressing the correct question, to which Justice Busby concluded they were not. As indicated in the concurrence, the actual question that should have been addressed is when the claims for interference with mineral rights accrued, essentially under these facts, could the Dickinson Ranch have asserted claims for interference to mineral rights in the 2014 litigation?[19] In this regard and as a point of clarity, the injury to subsurface mineral rights only occurs when the owner of those rights is hindered in its ability to exercise those rights, not at the time of migration as with a surface estate owner.[20]

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[15] *Id.*
[16] *Id.* at *2 (quoting *Lightning Oil*, 520 S.W.3d at 49; *Regency Field Servs., LLC v. Swift Energy Operating, LLC*, 622 S.W.3d 807, 820 (Tex. 2021)).
[17] *Id.* at *3.
[18] *Id.* (quoting *Schneider Nat'l Carriers v. Bates*, 137 S.W.3d 264, 275 (Tex. 2004)).
[19] *Id.* at * 5.
[20] *Id.* (citing *Regency*, 622 S.W.3d at 820).

Justice Busby did note that the end result, dismissal of Ageron's claims, may be correct, however it's reasoning to get to that result is flawed.[21]

Again, while this is merely a concurrence opinion rejecting a petition for review, Justice Busby's explication provides clarity in particular as to the facts and the established rules for claim accrual to a mineral interest owner's property rights. Further this concurrence provides a key outline for when injuries may be distinct and as such have separate accrual dates. In essence, while the concurrence has little precedential value in the traditional sense, it provides an important framework and roadmap to defending claims of injury to the mineral estate or vice versa in how to assess and determine when such claims have accrued.

[21] *Id.*

EPA Grants UIC Primacy to Texas for Class VI Wells for CCS

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On November 7, 2025, United States Environmental Protection Agency (EPA) Administrator Lee Zeldin signed off on the final rule grant Underground Injection Control (UIC) primacy to the Texas Railroad Commission (RRC) for injection well Class VI under the Safe Drinking Water Act (SDWA).[1] The final rule was published in the Federal Register on November 14, 2025, and will be effective thirty days after publication, on December 14, 2025.[2] This follows the EPA's publication of a proposed rule to grant primacy in the Federal Register on June 17, 2025[3], and Texas' filing its application for primacy on February 20, 2025, after a period of initial consultation with EPA.

Background

Congress enacted the SWDA in 1974 "to assure that water supply systems serving the public meet minimum national standards for protection of public health."[4] The SDWA protects drinking water systems in several ways. Part C of the SDWA seeks to protect underground sources of drinking water ("USDW") by directing the EPA to develop regulations for State UIC regulations, including "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources."[5]

Federal regulations promulgated to implement the SDWA establish six classes of injection wells and provide regulations for each class.[6] The original federal UIC regulations recognized five classes of wells—Classes I though V[7]—but Class VI was added in 2010 to regulate wells used to inject carbon dioxide for CCS.[8]

[1] *See* EPA's discussion of this at https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program#texas.
[2] 90 Fed Reg. 51021 (Nov. 14, 2025).
[3] *See* Fed. Reg. 25,547 (June 17, 2025).
[4] H.R. Rep. No. 93-1185 (1974).
[5] 42 U.S.C. § 300h(a)-(b).
[6] 40 C.F.R. § 144.6.
[7] Class I wells are wells used to inject wastes "beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water." 40 C.F.R. § 144.6(a). Class II wells are wells in which fluids are injected for disposal of produced water and certain wastewater associated with oil and gas production, "enhanced recovery of oil or natural gas," or for storage of liquid hydrocarbons. 40 C.F.R. § 144.6(b). Class III wells are wells associated with certain mining activities, such as solution mining. 40 C.F.R. § 144.6(c). Class IV wells are wells used for injection of wastes into a formation that contains an underground source of drinking water within one-quarter mile of the well. 40 C.F.R. § 144.6(d). Class IV wells were banned in 1984. Class V wells are injection wells that do not fit into any other category of injection well. 40 C.F.R. § 144.6(e).
[8] 75 Fed. Reg. 77230 (Dec. 10, 2010).

Primacy

Part C of the SDWA[9] provides two processes for States to seek primary enforcement authority—commonly called "primacy"—to implement and enforce the SDWA within their respective borders. When primacy for UIC regulations is granted, it is granted on a class-by-class basis. Thus, a state can receive primacy for one or more classes of injection wells, without receiving primacy for all classes. Indeed, a majority of states have primacy for some classes of injection wells, without having primacy for all classes.

Section 1422 of the SDWA (42 U.S.C. § 300h-1) provides the first process by which a state may obtain primacy for a class of wells. Under this process, a state can obtain primacy for a particular class of wells by demonstrating to the EPA that the state has implemented UIC rules for that class of wells that meet the federal regulatory standard for protecting USDWs. This Section 1422 process can be used to obtain primacy for any class of UIC wells. Pursuant to Section 1422, West Virginia obtained primacy for Class I, III, IV, and V wells in 1983.[10]

The second process for obtaining primacy is found in Section 1425 of the SDWA (42 U.S.C. § 300h-4). Section 1425 provides an alternative process that can be used to obtain primacy for Class II wells, though a state can use the Section 1422 process to obtain primacy for Class II wells if the state wishes. Class II wells are used for injection disposal of waste fluids from oil and gas activities, injection wells for secondary or tertiary recovery, and injection wells for subsurface storage of hydrocarbon liquids.

Texas's Application for Class VI Primacy

Texas has long had primacy for injection well classes I, II, III, IV, and V. Texas obtained primacy for Classes I, III, IV, and V under SDWA section 1425 on January 6, 1982. Texas obtained primacy for Class II under SDWA section 1422 on April 23, 1982.

In 2010, Texas finalized rules for geologic storage of carbon dioxide (CO_2) for carbon capture and storage (CCS). Texas amended those rules in 2012 and again in 2022. In response to comments from the EPA during preliminary consultations regarding a Class VI primacy application, Texas amended its rules regarding underground storage of CO_2 again in 2023. The Texas RRC applied for primacy for Class VI wells on February 20, 2025.

[9] Part C of the SDWA is found at 42 U.S.C. §§ 300h *et seq.*
[10] *See* 48 Fed. Reg. 55127 (Dec. 9, 1983).

Grant of Primacy

The EPA reviewed the RRC's Class VI primacy application to confirm that it was consistent with requirements established by the SDWA and the federal regulations promulgated under the SDWA, and the EPA determined that the application met all requirements. Accordingly, EPA published a proposed rule to grant Class VI primacy to the Texas RRC in June 2025, with a public comment period that ended in August, followed by the November 14, 2025 publication of a final rule to grant primacy as of December 15, 2025.

EPA Grants UIC Primacy to Arizona for Injection Well Classes I-VI

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On September 15, 2025, the United States Environmental Protection Agency (EPA) published a rule in the Federal Register, granting Underground Injection Control (UIC) primacy to the Arizona Department of Environmental Quality (ADEQ) for injection well Classes I-VI under the Safe Drinking Water Act (SDWA).[1] The final rule is effective on October 15, 2025, thirty days after publication.[2] This follows the EPA's publication of a proposed rule to grant primacy in the Federal Register on May 19, 2025.[3]

Background

Congress enacted the SWDA in 1974 "to assure that water supply systems serving the public meet minimum national standards for protection of public health."[4] The SDWA protects drinking water systems in several ways. Part C of the SDWA seeks to protect underground sources of drinking water ("USDW") by directing the EPA to develop regulations for State UIC regulations, including "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources."[5]

Federal regulations promulgated to implement the SDWA, establish six classes of injection wells and provide regulations for each class.[6] The original federal UIC regulations recognized five classes of wells—Classes I though V[7]—but Class VI was added in 2010 to regulate wells used to inject carbon dioxide for CCS.[8]

Primacy

Part C of the SDWA[9] provides two processes for States to seek primary enforcement authority—commonly called "primacy"—to implement and enforce the

[1] 90 Fed. Reg. 44,327 (Sept. 15, 2025).
[2] *Id.*
[3] Fed. Reg. 21,264 (May 19, 2025).
[4] H.R. Rep. No. 93-1185 (1974).
[5] 42 U.S.C. § 300h(a)-(b).
[6] 40 C.F.R. § 144.6.
[7] Class I wells are wells used to inject wastes "beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water." 40 C.F.R. § 144.6(a). Class II wells are wells in which fluids are injected for disposal of produced water and certain wastewater associated with oil and gas production, "enhanced recovery of oil or natural gas," or for storage of liquid hydrocarbons. 40 C.F.R. § 144.6(b). Class III wells are wells associated with certain mining activities, such as solution mining. 40 C.F.R. § 144.6(c). Class IV wells are wells used for injection of wastes into a formation that contains an underground source of drinking water within one-quarter mile of the well. 40 C.F.R. § 144.6(d). Class IV wells were banned in 1984. Class V wells are injection wells that do not fit into any other category of injection well. 40 C.F.R. § 144.6(e).
[8] 75 Fed. Reg. 77230 (Dec. 10, 2010).
[9] Part C of the SDWA is found at 42 U.S.C. §§ 300h *et seq.*

SDWA within their respective borders. When primacy for UIC regulations is granted, it is granted on a class-by-class basis. Thus, a state can receive primacy for one or more classes of injection wells, without receiving primacy for all classes. Indeed, a majority of states have primacy for some classes of injection wells, without having primacy for all classes.

Section 1422 of the SDWA (42 U.S.C. § 300h-1) provides the first process by which a state may obtain primacy for a class of wells. Under this process, a state can obtain primacy for a particular class of wells by demonstrating to the EPA that the state has implemented UIC rules for that class of wells that meet the federal regulatory standard for protecting USDWs. This Section 1422 process can be used to obtain primacy for any class of UIC wells. Pursuant to Section 1422, West Virginia obtained primacy for Class I, III, IV, and V wells in 1983.[10]

The second process for obtaining primacy is found in Section 1425 of the SDWA (42 U.S.C. § 300h-4). Section 1425 provides an alternative process that can be used to obtain primacy for Class II wells, though a state can use the Section 1422 process to obtain primacy for Class II wells if the state wishes. Class II wells are used for injection disposal of waste fluids from oil and gas activities, injection wells for secondary or tertiary recovery, and injection wells for subsurface storage of hydrocarbon liquids.

Arizona's Application for Primacy

Arizona has never before had primacy for any class of injection wells under the SDWA's UIC program. However, the ADEQ promulgated state UIC regulations, which became effective on September 6, 2022. In 2023, ADEQ published notices of its intent to apply for UIC primacy and it accepted written comments and held public meetings for comments. On February 16, 2024, ADEQ applied to the EPA for primacy for Classes I, II, III, IV, V, and VI under the UIC program. ADEQ also entered into a Memorandum of Agreement with EPA's Region 9 Office.

Grant of Primacy

The EPA reviewed ADEQ's application for consistency with requirements established by the SDWA and the federal regulations promulgated under the SDWA, and the EPA determined that the application met all requirements. Accordingly, EPA published a proposed rule to grant primacy to ADEQ for Classes I-VI in May 2025 and a final rule in September 2025, with an effective date of October 14, 2025.

[10] *See* 48 Fed. Reg. 55127 (Dec. 9, 1983).

Ohio Court Rejects Challenges to State Land Leasing Legislation

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Environmental groups upset with the leasing of state lands for oil and gas development in Ohio have turned to the courts for relief in recent years. In each case, however, their challenges have been denied. In their latest challenge, these groups asked the court to find that recent legislative changes to the state land leasing process were unconstitutional.[1] The court of common pleas (Ohio's trial court) rejected those efforts, finding that the remedies sought by the environmental groups were moot as a matter of law, and even if not, plaintiffs lacked the standing necessary to bring their claims.

The complaint brought by plaintiffs was straightforward: they sought declarations that HB 507 was unconstitutional under both Ohio's one-subject rule and Ohio's three-consideration rule (i.e., Article II, Sections 15(D) and 15(C) of the Ohio Constitution, respectively). HB 507 was the legislation that amended the state land leasing process to require state agencies to lease public lands until the leasing commission promulgated certain rules that they had, up until that point, failed to issue. The constitutional provisions relied on by plaintiffs state that "[n]o bill shall contain more than one subject" and that "[e]very bill shall be considered by each house on three different days."

The court first found that the expiration of HB 507's mandatory leasing provision rendered much of plaintiffs' claims moot. That is, the commission had already adopted the required administrative rules by the time the court issued its decision, and no entities had signed leases under that provision while it was in effect, rendering the requests for declaratory and injunctive relief largely of no practical effect.

Moreover, to the extent that some of plaintiffs' claims were not rendered moot by the passage of commission rules, the court further found that plaintiffs lacked standing to bring them. The court observed first: "'Before an Ohio court can consider the merits of a legal claim, the person or entity seeking relief must establish standing to sue.' . . . 'Standing to sue is part of the general understanding of what makes a case justiciable and is a 'jurisdictional requirement.''" Here, plaintiffs argued that they had both "organizational" standing (i.e., the environmental entities had standing based on the impacts to the entities themselves) and "associational" standing (i.e., standing to bring suit on behalf of their members). The court rejected both arguments.

The court first rejected the argument that plaintiffs had organizational standing, finding that plaintiffs had failed to show that the legislation frustrated their organizational mission or caused them to divert resources—i.e., to spend additional resources that they would not have otherwise spent. "As was succinctly summarized by the State, 'Plaintiffs fail to present any evidence, beyond amorphous conclusory statements provided in affidavits that they diverted resources as the result

[1] *See Ohio Environmental Council v. State of Ohio*, Case No. 23-CV-002403.

of [] H.B. 507.'" The court next rejected the argument that plaintiffs had associational standing, finding that to have standing to challenge the constitutionality of an enactment, private litigants must show they have suffered a concrete injury "in a manner or degree [that is] different from that suffered by the public in general." Here, plaintiffs failed to do so—"the Court cannot conclude that the State's alleged violations of those rules have harmed Plaintiffs or their members in a distinct way from the public at large. That conclusion is distinctly true because the Mandatory Leasing Provision no longer poses a threat to Plaintiffs and their members."

This decision is almost certain to be appealed to the Tenth District Court of Appeals, and if it is, we will report back on any subsequent developments.

Pennsylvania Federal Court Decides Issues in Lease Formation Dispute

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LSU Law Center

In *Warner v. Shell Legacy Holdings, LLC*, 2025 WL 2783702 (W.D. Pa. 2025), the court resolved several issues in ruling on motions for summary judgment. The *Warner* plaintiffs alleged that the defendants failed to pay bonuses due under oil and gas leases covering tracts in Pennsylvania. The plaintiffs were individuals who had been class members in a prior class action in which the court decertified the class,[1] finding that the requirements for class certification were no longer satisfied.

Background

Between 2011 and 2013, SWEPI LP actively sought oil and gas leases in certain portions of Pennsylvania. SWEPI's general practice was to use a pre-printed lease form, along with an addendum to the lease form, a memorandum of lease, and a bank draft issued to the landowner, stating the amount of the lease bonus. Neither the pre-printed lease form nor the addendum stated the amount of the lease bonus. The bank drafts typically provided that SWEPI would have a stated amount of time—in many of the drafts, the period was 90 banking days—"for title examination and payment." The drafts also stated, "[n]o liability for payment or otherwise shall be attached to any of the parties hereto."

After a landowner signed the lease form and memorandum of lease, SWEPI would begin a thorough title examination. However, because so many other companies were also taking leases and conducting title examinations, recorders' offices became crowded, and the commissioners of Venango County limited the time that each company's representatives could spend in the recorder's office to 90 minutes per day. Because of this 90-minute limitation, SWEPI could not complete title examinations for many of the tracts of land whose owners had signed leases.

SWEPI paid the bank drafts for some lease tracts, but canceled the drafts for many other tracts and surrendered the associated leases. SWEPI canceled drafts and surrendered leases for various reasons, including the inability to complete title examinations for some tracts, title problems that SWEPI found for other tracts, and a decrease in the price of natural gas that made leasing less desirable. Certain individuals whose leases had been canceled filed a putative class action, claiming that SWEPI had no right to cancel their leases and that SWEPI had breached its lease obligations by failing to pay the promised leases bonuses. The court granted class certification, but later the court decertified the class.

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[1] *See Walney v. SWEPI LP*, 2019 WL 1436938 (W.D. Pa. 2019).

After the class was decertified, some former members of the decertified class filed *Warner* to assert breach of lease claims. Both the *Warner* plaintiffs and the defendants filed motions for summary judgment.

The Parties' Arguments

The plaintiffs argued that the signed lease forms, together with the addenda, formed complete and binding contracts. They asserted that the memoranda of lease and the drafts were not part of the contracts. They argued that the limitation of liability language in the bank drafts merely meant that SWEPI would not be liable if it did not honor the drafts as the particular form of payment for the lease bonuses, but that the language did not give SWEPI the right to cancel the leases and did not relieve SWEPI of an obligation to pay the bonuses.

The defendants argued that, for each prospective lease, the pre-printed lease form, addendum, memorandum of lease, and draft were all part of a single contract. They also asserted that there was no binding lease until SWEPI accepted a lease and paid the bonus. They argued that the limitation of liability language in the bank drafts precluded any liability to pay a lease bonus if SWEPI chose to cancel a lease, without regard to the reason SWEPI canceled the lease or even if SWEPI had no reason for cancelling the lease.

In addition, the defendants argued that some of the plaintiffs lacked marketable title and that, even if SWEPI did not have a right to cancel a lease without having a reason, the lack of marketable title gave SWEPI the right to cancel those leases. Further, the defendants argued that, to the extent that the limitations imposed by officials in Venango County made it impossible for SWEPI to complete a title examination and verify the lessors' good title within 90 days as to some tracts, SWEPI was entitled to cancel the leases for those tracts. Finally, the defendants asserted that the claims of some plaintiffs should be dismissed because those plaintiffs had never submitted their bank drafts for payment.

Court's Reasoning

The court stated that, under Pennsylvania law, when parties contemporaneously execute multiple instruments as part of a single transaction, the instruments collectively form a single contract. Accordingly, the lease forms, addenda, memoranda of lease, and bank drafts were all part of the parties' contracts, and the court rejected the plaintiffs' argument to the contrary. Further, the court rejected the plaintiffs' argument that the limitation of liability language in the bank drafts merely excused SWEPI from liability to use the drafts as the form of payment, while leaving in place SWEPI's obligation to pay the bonus on each lease. The court concluded that, when the limitation of liability language applied, it meant that SWEPI had no obligation to pay a lease bonus.

But the court rejected the defendants' argument that the limitation of liability language meant that SWEPI could cancel a lease for any reason whatsoever and even if SWEPI had no reason. Instead, the court concluded that the limitation of liability applied only if SWEPI found a title problem for a particular tract within 90 days of a lease being signed. The court stated that SWEPI could not cancel a lease merely because it had been unable to verify the lessor's good title because of SWEPI's inability to complete a title examination due to the restrictions imposed by officials in Venango County. Thus, the risk of being unable to complete a title examination fell on SWEPI.

The court granted summary judgment to the defendants as to tracts where the undisputed facts showed that SWEPI canceled the leases within 90 days due to a title defect. The court also granted summary judgment to the defendants as to certain plaintiffs, when undisputed facts showed that those plaintiffs had never submitted their drafts for payment. As to other plaintiffs, the court denied the defendants' motion for summary judgment, concluding that the defendants had not shown that the plaintiffs had failed to present a bank draft for payment or that SWEPI had canceled the leases within 90 days due to a title defect.

Finally, the court noted that it previously had held that, if SWEPI canceled leases without having a right to do so, the plaintiffs' whose leases were canceled had a duty to mitigate their damages. The duty to mitigate would include a duty to re-lease the property if an opportunity to do so arose. Certain plaintiffs actually had re-leased their properties, and the court stated that any damages to which those plaintiffs might be entitled would be reduced by the bonus payments they received when they re-leased the properties, but that contrary to the defendants' assertions, the plaintiffs' recovery should not be reduced by any royalty payments that they received.

In addition, the court held that undisputed facts showed that one plaintiff had an opportunity to re-lease, but he failed to do so. That plaintiff's recovery, if any, would be reduced by the bonus payment that he would have received if he had taken the opportunity to re-lease the property.

On Rehearing, West Viriginia's Top Court Sticks to Expansion of Marketable Title Rule

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In *Romeo v. Antero Resources Corp.*, 917 S.E.2d 26 (W. Va. 2025), the plaintiffs brought a class action in state court, arguing that Antero Resources had underpaid the royalites owed under oil and gas leases covering land in Harrison County, West Virginia. The case was later removed to the United States District Court for the Northern District of West Virginia. The federal district court eventually certified two questions concerning the calculation of the royalty owed on the sale of natural gas liquids (NGLs) to the West Virginia Supreme Court of Appeals. The Supreme Court accepted the certified questions, and in November 2024 the Court issued a judgment answering the questions by expanding the marketable title rule, making it a point-of-sale rule.[1] This was reported in the December 2024 issue of the Oil & Gas E-Report.

The Supreme Court granted a rehearing and set the matter for re-argument, giving some hope to the lessee defendants, but on rehearing the Court reached the same result. The Court issued a new opinion that superseded the November 2024 opinion, but language of the new opinion tracked the language of the prior opinion very closely, with much of it following the superseded opinion word-for-word.

Background

Royalty disputes often have arisen when an oil and gas lease provides for the lessee to pay a royalty based on the value of natural gas *at the well*, but the natural gas is sold away from the well—often after the lessee has processed the gas to remove impurities and transported the gas to a distant market. These post-production activities add value to the gas, but the lessee also incurs costs to perform these activities. More importantly, because the sale of gas does not occur at the well, and because the gas does not have the same properties (such as composition) at the time of sale as the gas had at the well, the sales price does not necessarily represent the value of the gas at the well.

Lessees often seek to use the "workback" or "netback" method to calculate an estimated value of the gas at the well by starting with the sales price of the gas (after processing and transport) and then subtracting the "post-production" costs of processing and transporting the gas. And there is an undeniable economic logic to this calculation as a method (though not necessarily a perfect method) of estimating the value of the gas at the well when the sale does not occur at the well.

[1] *See Romeo v. Antero Resources, Corp.*, 2024 WL 4784706 (W. Va. 2024).

Of course, royalty owners would prefer to be paid a royalty based on the sales price, rather than a royalty based on the sales prices minus post-production costs. Indeed, they often argue that the royalty must be based on the sales price, rather than the sales price minus the post-production costs. They do not typically argue that the sales price is a better estimate of the value of the gas at the well than the sales price minus post-production costs. Instead, they typically argue either that the lessee has an implied duty to pay for post-production costs relating to marketing or that a lease's royalty clause is ambiguous if it bases the royalty on the value at the well when the gas is not sold at the well.

The traditional or majority rule is that, if a lease provides for royalties to be based on market value at the well, but the gas is not sold at the well, it is permissible for lessees to use the workback method to estimate the market value at the well. However, some states have adopted a "marketable product rule," including Colorado, Kansas, Oklahoma, and West Virginia. Under this rule, a lessee must absorb all the costs necessary to make the gas marketable. Thus, in calculating the royalty, the lessee cannot subtract (from the sales price) the post-production costs necessary to make gas marketable, unless the lease expressly authorizes the deduction of those costs.[2]

However, even in the marketable product rule states, the lessee generally can deduct any post-production costs that go beyond what is necessary to make a product marketable, provided that those costs add value. Thus, if removing a given amount of impurities would allow marketing of the gas (and cost the lessee a given amount of money), but the lessee incurs an incrementally higher expense to remove a greater amount of the impurities, the lessee could deduct the incremental expense of the additional processing from the sales price, provided that removing the additional impurities made the gas more valuable.

This Dispute

One of the leases at issue in this case provided for a royalty on gas equal to one-eighth "of the value at the well of the gas." The other provided for a royalty on gas equal to one-eighth of the "gross proceeds received from the sale of the same at the prevailing price for gas sold at the well." The parties disputed how to calculate the royalty on natural gas liquids (NGLs) extracted from natural gas during processing of the gas. The lessors argued that they should be entitled to one-eighth the price at which the NGLs were sold.

The lessees argued that, notwithstanding jurisprudence from the West Virginia Supreme Court of Appeals that applies the marketable product rule, this rule should not apply to NGLs, as opposed to natural gas. The lessees also may have hoped that the West Virginia Supreme Court would discard the marketable-

[2] *See Wellman v. Energy Resources, Inc.*, 557 S.E.2d 254 (W. Va. 2001); *Estate of Tawney v. Columbia Natural Resources, L.L.C.*, 633 S.E.2d 22 (W. Va. 2006).

product rule altogether, given language in a West Viriginia Supreme Court decision that criticized the Court's own marketable product rule jurisprudence.

The Supreme Court's majority rejected the lessee's arguments by a 3-to-2 vote on original hearing. The majority acknowledged the language in a prior decision that criticized the Court's own marketable product jurisprudence, but the majority characterized that criticism as "dicta" and an "indulgent frolic." The majority also rejected the lessee's argument that marketable product rule is bad public policy, stating that it is the legislature's job, not the Court's job, to consider public policy. Likewise, the majority rejected the lessee's argument that the marketable product rule should be limited to natural gas itself, not to NGLs.

The lessees noted that, in all the other marketable product rule states, the marketable-product rule only prohibits the deduction of the expenses necessary to make the product marketable. If a lessee incurs post-production costs above and beyond the amount necessary to make the product marketable—for example, to remove more impurities than necessary to make the gas marketable—the lessee is allowed to deduct the incremental portion of post-production costs from the sales price, provided that performing the extra work adds value to the gas (value in which the lessor would share given that the sales price presumably would reflect the additional value and the incremental costs would be subtracted from this higher sales price).[3]

The majority stated, however (assuming the lease does not expressly provide for such deductions), that even if the lessee incurs more post-production costs than necessary to make gas marketable, and even if the extra work adds value to the gas, a rule prohibiting the deduction of all post-production costs still is most consistent with West Virginia jurisprudence. The majority acknowledged that its holding—which the majority dubbed the "point of sale" rule—"may make West Virginia a minority of one."

The dissenting justices vigorously disagreed with the majority's original hearing decision. One of two dissenting opinions criticized the marketable product rule itself, stating that the workback method is more consistent with a plain meaning of "at the well" royalty clauses than is the marketable product rule.[4]

Another dissenting opinion did not seek to overturn West Virginia's version of the marketable product rule, as established by *Wellman* and *Tawney*. However, this second dissenting opinion disagreed with the majority's conclusion that its newly pronounced "point of sale" rule naturally follows from the Court's existing marketable product rule jurisprudence. This dissenting opinion concluded that the point-of-sale rule is an unwarranted extension of the marketable product rule. This

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[3] *See Garman v. Conoco*, 886 P.2d 652 (Colo. 1994); *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 800 (Kan. 1995); *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203, 1207 (Okla. 1998).
[4] *Romeo*, 2024 WL 4784706 (Walker, J.).

dissent asked where the marketable product rule ends. If, for example, instead of the lessee selling the NGLs, the lessee instead had used the NGLs to manufacture plastics, would the lessee have to pay a royalty on the sales price for the plastics?[5]

The Supreme Court's original decision was issued in November 2024. In December 2024, the Court granted a rehearing and set the case for re-argument. On rehearing, the Court reached the same result. It issued a new opinion that superseded the opinion issued on original hearing, but the new opinion reached the same result and used much the same language as the superseded opinion. Justice Walker again dissented, issuing an opinion almost identical to his prior dissenting opinion. Justice Bunn again dissented, issuing an opinion that made similar points as did his prior dissent. On original hearing, Justice Hutchison stated that he agreed with the majority opinion, but he also submitted a concurring opinion. On rehearing he merely joined the majority opinion and did not file a concurring opinion.

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[5] *Romeo*, 2024 WL 4784706 (Bunn, J.).

Three Key Federal Updates Pipeline Operators Need to Track

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Recently, three significant regulatory updates have been issued that pipeline operators should track closely. First, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published in the Federal Register a Final Rule titled "Periodic Standards Update II" (Final Rule), which incorporates by reference 19 updated industry standards and clarifies several regulatory provisions. Second, PHMSA released updated hazardous liquid high consequence area (HCA) data layers through the National Pipeline Mapping System (NPMS). Finally, the Department of Transportation (DOT) issued a notice of proposed rulemaking (NPRM) on drug-and-alcohol (D&A) testing requirements that will affect PHMSA-jurisdictional operators.

These updates carry both near-term compliance steps and longer-term program implications. Below, we break down each development and highlight the actions pipeline operators should consider.

Periodic Standards Update II Final Rule

On September 10, PHMSA finalized its Periodic Standards Update II, a follow-up to its August 2022 NPRM. This rule incorporates by reference 19 updated industry standards, introduces clarifying edits to existing regulatory language, and replaces several outdated references. Importantly, these updates are in addition to those adopted earlier this year in PHMSA's June 2025 direct final rule.

The new rule also makes a key update to "49 CFR Part 192, Appendix G," which provides guidance on identifying moderate consequence areas (MCAs). Where operators once had to cross-reference definitions from the Federal Highway Administration (FHWA), Appendix G now consolidates key roadway classifications — including "other principal arterial," "minor arterials," and "major and minor collectors" — directly within PHMSA's regulatory framework. This move is intended to simplify compliance and reduce reliance on external FHWA publications.

The Final Rule will take effect on January 10, 2026, giving operators about three months to review and align their integrity, construction, and maintenance programs with the updated references.

Standards Incorporated by Reference

The updated standards are grouped by their issuing organizations, with highlights including:

- American Petroleum Institute (API)
  - API RP 652, Linings of Aboveground Petroleum Storage Tank Bottoms, 5th Edition (2020)
  - API RP 2003, Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents, 8th Edition (2015, reaffirmed 2020)
  - API Spec 12F, Shop-welded Tanks for Storage of Production Liquids, 13th Edition (2019)
  - API 510, Pressure Vessel Inspection Code, 10th Edition (2014 with 2017 addendum) API Std 2510, Design and Construction of LPG Installations, 9th Edition (2020)
- American Society of Mechanical Engineers (ASME)
  - ASME B16.40-2019, Thermoplastic Gas Shutoffs and Valves
  - ASME B31.4-2019, Pipeline Transportation Systems for Liquids and Slurries
- American Society for Nondestructive Testing (ASNT)
  - ANSI/ASNT ILI-PQ-2017, In-line Inspection Personnel Qualification
- Association for Materials Protection and Performance (AMPP, formerly NACE)
  - NACE SP0102-2017, In-Line Inspection of Pipelines
- ASTM International
  - Updates across a wide range of material, fitting, and welding standards, including ASTM D2513-20 (Polyethylene Gas Pressure Pipe) and ASTM F2620-20ae2 (Heat Fusion Joining of Polyethylene Pipe and Fittings)
- National Fire Protection Association (NFPA)
  - NFPA 30, Flammable and Combustible Liquids Code, 2021 Edition

For operators, the incorporation of these standards means more than just updating library shelves. In many cases, design, inspection, and qualification practices will need to be revisited. Engineering groups should begin reviewing project specifications, while compliance teams should map out any implementation gaps ahead of the January 2026 effective date.

Hazardous Liquid HCA Layer Updates

PHMSA has also updated its hazardous liquid HCA mapping layers, a critical input for integrity management program (IMP) requirements under 49 CFR Part 195.

The new release includes Version 6 of the high population area and other population area GIS layers. In addition, Ecological Unusually Sensitive Area data has been updated and is now available either by request or via the operator viewer in PIMMA (PHMSA's Pipeline Integrity Management Mapping Application).

These HCA layers form the baseline against which operators must compare their pipeline centerlines to determine whether their assets could affect identified HCAs. In turn, those determinations drive IMP obligations, assessment schedules, and remediation priorities.

Operators should take the following actions in response to the new layers:

- **Download and review** the updated datasets from NPMS or PIMMA.
- **Reevaluate HCA determinations** regarding hazardous liquid assets, paying particular attention to whether new population growth or ecological features have altered coverage.
- **Document changes** to pipeline mileage within HCAs, since total HCA footage often ties directly into annual reporting and inspection schedules.

DOT NPRM on Drug & Alcohol Testing

Finally, the DOT issued an NPRM to amend 49 CFR Part 40, which governs drug-testing procedures for transportation workplaces.

The NPRM would:

- **Add fentanyl and norfentanyl** to DOT's drug-testing panel.
- **Harmonize with HHS Mandatory Guidelines** where appropriate.
- **Clarify existing provisions** within Part 40 and implement technical amendments.

For pipeline operators, the connection lies in 49 CFR Part 199, which incorporates DOT's Part 40 by reference for PHMSA-regulated entities. In practice, this means that once Part 40 is amended, operators must update their D&A testing programs accordingly.

Key Considerations for Operators

- **Testing panels**: Current policies will need to be revised to capture fentanyl/norfentanyl once the rule is finalized.
- **Program alignment**: Operators should begin coordinating with third-party testing administrators and medical review officers to understand potential implementation impacts.
- **Comment deadline**: Stakeholders have until October 17, to submit comments to DOT. Operators who anticipate operational challenges (e.g., with testing technology, false positives, or workforce communication) may want to provide feedback before the rule is finalized.

This NPRM reflects DOT's broader efforts to address the opioid epidemic and ensure that transportation workplaces — including pipeline operations — remain safe and drug free.

Practical Takeaways

Recent times have brought a surge of federal activity, and pipeline operators should move quickly to get ahead of the curve:

1. **Review the Final Rule**: Assign engineering and compliance teams to review the 19 updated standards and assess whether construction, inspection, and maintenance practices will need revision before January 2026.
2. **Update HCA analyses**: Download the new NPMS datasets, update HCA determinations, and document any changes for regulatory reporting and IMP compliance.
3. **Prepare for D&A program changes**: Monitor the DOT NPRM; consider filing comments by October 17; and start planning for potential program revisions once fentanyl and norfentanyl are formally added to the testing panel.

By staying proactive on these fronts, operators can reduce compliance risk, streamline implementation, and demonstrate to regulators a strong culture of safety and accountability.

Conclusion

Regulatory changes often arrive in clusters, and this month is no exception. With PHMSA's incorporation of new industry standards, the updated HCA mapping layers, and DOT's proposed drug testing amendments, pipeline operators face a range of near- and medium-term compliance tasks. Monitoring these updates closely — and mobilizing teams to address them early — will position operators to stay ahead of enforcement deadlines and maintain safe, compliant operations.

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