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U.S. District Court Holds Oil and Gas Rights Under Lease to Be Divisible, Implied Covenant to Develop Can Arise During Secondary Term

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Recently, in *Reed v. Columbia Gas Transmission, LLC*, 2025 U.S. Dist. LEXIS 97839, the U.S. District Court for the Southern District of Ohio, Eastern Division was tasked with deciding multiple issues of first impression in Ohio related to an oil and gas lease that has been held into its secondary term by continuous gas storage operations since 1952. The plaintiffs James and Deborah Reed (the "Reeds") and defendants Columbia Gas Transmission, LLC ("Columbia") and Columbia Energy Ventures, LLC ("Columbia EV") are the successors to the original lessors and lessee under the lease, respectively.

Background

In 1950, the predecessors to the Reeds entered into an oil and gas lease with the Ohio Fuel Gas Company ("Ohio Fuel") covering 80 acres in Hocking County, Ohio ("1950 Lease"). The 1950 Lease granted Ohio Fuel the rights to drill, produce, and market oil and gas, with a 20-year term that could continue as long as oil or gas was produced in paying quantities. The 1950 Lease also required Ohio Fuel to drill a well within one year or pay delay rentals, but no wells were drilled under the 1950 Lease. In 1952, the parties entered into a superseding lease ("1952 Lease") to add the right to inject, store, and remove gas, but otherwise included similar terms to the 1950 Lease. For example, both leases permitted the lessor to install a line from one dwelling to any gas well drilled on the lease and take a certain volume of free gas each year. No oil or gas was ever produced from the 1952 Lease, but three gas storage wells were drilled under the lease and one of those storage wells was used to supply gas to a cabin on the lessor's property.

From 1995 to 2011, Columbia conducted oil and gas exploration activities in the region and drilled forty-eight wells, but none of the wells were drilled under the 1952 Lease. However, twenty-six of the wells drilled were "dry holes" and only a handful were profitable. In 2021, the Reeds received notice of Columbia's intent to plug and abandon four gas storage wells, including the well supplying gas to the cabin. Less than a year later, Columbia plugged all four gas storage wells. The Reeds filed a complaint against Columbia and Columbia EV in state court, which Columbia removed to federal court. The Reeds filed an amended complaint asserting eight claims, including a claim for breach of the implied covenant to produce. Both parties moved for summary judgment on this issue.

Implied Covenant to Develop During Primary Term

The court began its analysis by clarifying that the "implied covenant to produce" is more accurately called an "implied covenant to develop" because it refers to an obligation to make *reasonable efforts to develop* oil and gas, as opposed to an absolute duty to produce. The court then recognized that the Ohio

Supreme Court has not imposed an implied covenant to develop during the primary term if the lease (i) contains an express disclaimer of implied covenants or (ii) requires development to commence within a certain period. *State ex rel. Claugus Family Farm, L.P. v. Seventh Dist. Court of Appeals*, 2016-Ohio-178, 186. In *Claugus*, the Ohio Supreme Court held that the second method for precluding the implied covenant of development can be satisfied by the combination of the (i) "drill or pay" language in the typical delay rental provision and (ii) the definite time period of the primary term in the habendum clause. Here, the 1952 Lease included such "drill or pay language" requiring the lessee to drill a well (producing in paying quantities or used for storage) by a certain date or pay a delay rental to the lessor. Because the 1952 Lease also contained a twenty-year primary term, the court held that the 1952 Lease precluded the imposition of an implied covenant to develop during the *primary term*.

Implied Covenant to Develop During Secondary Term

However, the court noted the lease in *Claugus* was still within its primary term, while the 1952 Lease has not expired due to continuous gas storage operations. Because the 1952 Lease is in its secondary term, the next issue considered by the court was whether an implied covenant to develop should arise during the secondary term. Columbia argued the implied covenant to develop does not apply to dual purpose leases like the 1952 Lease so long as one of the dual purposes (production or storage) is being served. The court rejected Columbia's broad proposition that the implied covenant to develop never arises under a dual purpose lease, but agreed courts should consider the language and express purposes of the lease when determining whether the implied covenant should be imposed.

Are Oil Rights and Gas Rights Divisible Under 1952 Lease?

After reviewing the 1952 Lease, the court noted that it does not contain any language stating that it is entire and indivisible. Furthermore, the 1952 Lease apportions compensation due for oil production independently from the compensation due for gas production or storage. As a consequence, separate causes of action could arise for a breach of the duty to pay the oil royalties and a breach of the duty to pay the gas well rentals. After weighing these factors, the court determined that the 1952 Lease is divisible between oil rights and gas rights. However, the court stressed that its analysis is provisional for the purpose of resolving the current cross-motions and is without prejudice to reconsideration. Upon determining that the oil and gas rights are divisible, the court next considered whether the implied covenant to develop arises for each type of production.

As to gas production, the court held that *no* implied covenant to develop exists because the contracting parties to the 1952 Lease (i) expressly contemplated a possibility that gas would only be stored and not produced and (ii) agreed that storage alone would not only hold the lease but also provide the means of compensation for the lessor. Therefore, the court concluded that the implied covenant of development was precluded under Ohio law as to gas rights because the 1952 Lease describes how the development of the gas rights should occur in the secondary term in the terms of the lease itself.

As to oil production, the court held that an implied covenant to develop *does arise* under the 1952 Lease. Importantly, the court clarified that its conclusion was based upon its provisional finding that oil rights are divisible from gas rights. The court observed that the only oil right granted under the 1952 Lease is production and the landowner's compensation for that right is limited to one-eighth of the oil produced. This contrasts with the gas rights under the 1952 Lease, where the parties agreed that either production or storage would fulfill their intent regarding the development of gas rights and provide compensation beyond royalties. Moreover, the court rejected Columbia's argument that simply holding a lease during the secondary term is sufficient to preclude the implied covenant to develop from arising. In the court's view, the issue of whether the lease continues to be valid into the secondary term is a different issue from whether an implied covenant arises. Therefore, the court found that the 1952 Lease does *not* preclude the implied covenant of development from arising under Ohio law because it does not set forth how the development of oil rights should occur in the secondary term in the terms of the lease itself.

Plaintiff Has Burden of Proving Breach of Implied Covenant

The court acknowledged that when an implied covenant to develop is imposed, the lessee owes a duty to act as a reasonably prudent operator would as it develops the land under the lease. Whether the lessee has breached the implied covenant of reasonable development should be determined by the facts and circumstances of each particular case. The burden is on the plaintiff to show that oil exists under their lands "in sufficient quantity to warrant the expense of drilling and marketing." *Ohio Fuel Supply Co. v. Shilling*, 101 Ohio St. 106, 109. Here, the Reeds admitted that they could not prove there are oil reserves beneath their property and their own expert witness testified that the likelihood of oil reserves existing is "low." Therefore, the court found that the Reeds fell well short of meeting their burden of proof and denied their motion for summary judgment.

Conversely, the court held that Columbia conclusively demonstrated that it took reasonable steps to develop its oil and gas interests and granted its motion for summary judgment. Specifically, the court highlighted the oil and gas exploration conducted by Columbia in the region from 1995 to 2001, the millions of dollars spent on 2D seismic surveys (including one of the Reeds' property), and the forty-eight wells drilled by Columbia on lands where a seismic survey indicated the presence of potentially viable reserves.

Summary

Although the court's finding that oil rights are divisible from gas rights is provisional, the door has been opened for lessors in Ohio to assert a claim for breach of the implied covenant to develop the oil *or* gas rights granted under lease during its secondary term. However, as the court noted, whether the lessee has breached the implied covenant of reasonable development should be determined by the facts and circumstances of each particular case. Furthermore, under Ohio law, the remedy for a breach of an implied covenant, without more, is damages and the lessor has the burden of proving that damages would be an inadequate remedy. Therefore, although the door has been opened for lessors in Ohio, those who choose to enter will face multiple hurdles when bringing such a claim.

Is (Produced) Water… Water? The Texas Supreme Court's Ruling on the Rights of Produced Water

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On June 27, the Supreme Court of Texas issued its long-awaited ruling in *Cactus Water Services, LLC v. COG Operating, LLC* addressing the ownership of produced water under an oil and gas conveyance. In *Cactus Water*, the Court held that where an oil and gas conveyance contract is silent on the rights of produced water (water extracted along with oil and gas), the exclusive rights and obligations to the produced water belong to the mineral interest lessee — not the landowners.

The disposal of produced water is often one of the costliest aspects of drilling operations. The burden and expense of produced water disposal has typically always rested on the lessee. Recent technological advancements have created new uses for the produced water in other industries such as agriculture, manufacturing, or energy production. If treated, produced water can have many potential uses.

The underlying dispute arose when the landowners entered into produced water lease agreements (PWLAs) with Cactus Water Services LLC. The PWLAs purported to convey all rights to, the title to, and interest in the produced water on the oil and gas leases operated by COG Operating LLC. Following the execution of the PWLAs, Cactus Water attempted to enforce its rights over the produced water from COG's drilling operations on the landowners' property. Cactus Water and the landowners argued that the oil and gas lease only conveyed the lessee rights to explore for, produce, and keep "oil and gas" or "oil, gas, and other hydrocarbons" — not the produced water.

Under Texas law, ordinary water is not considered to be part of the mineral estate. Unless expressly severed, subsurface water remains part of the surface estate subject to the mineral estate's implied right to use the surface — including water — as reasonably necessary to produce and remove minerals. Thus, Cactus Water argued that the landowners maintained the full right to convey their interest in the produced water. While COG did not presently have an interest in obtaining value from the produced water, it still objected to Cactus Water's exercise of control over the produced water because Cactus Water was not equipped to manage and transport the produced water in a manner that would allow for uninterrupted exploration of the oil and gas lease.

The Court agreed with COG and found that produced water is not water that remains part of the surface estate. Rather, as has been understood for many years, produced water is oil and gas waste, which operators bear the burden, right, and duty of possessing, handling, and disposing. The Court emphasized that Texas law has long recognized that the hydrocarbon producer's possession and control over the disposition of liquid waste is necessarily incidental to, and therefore encompassed in, a conveyance of oil and gas rights. Thus, the conveying parties, which are presumed to contract in reference to the law, understood that the disposal of liquid waste meant the consumption of the capital value, if any, of constituent water.

Key Takeaways

This decision is consequential as it provides clarity for the ever-changing business of produced water. Oil and gas waste, including produced water, belongs to the lessee unless specifically reserved. The decision provides clarity for midstream and water recycling arrangements in Texas going forward by putting to bed the debate over the nature of produced water. Such a clear legal framework will benefit economic endeavors. In light of new technological developments, we may continue to see more disputes over produced water ownership.

EPA Proposes to Grant SDWA Class VI Primacy to Texas

Keith B. Hall
LSU Law Center

The United States Environmental Protection Agency (EPA) published a proposed rule in the Federal Register on June 17, 2025 to grant Underground Injection Control (UIC) primacy to the Texas Railroad Commission (RRC) for Class VI injection wells under the Safe Drinking Water Act (SDWA). *See* Fed. Reg. 25,547 (June 17, 2025). The public comment period closed on August 1, 2025.

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."[1] 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."[2]

Federal regulations promulgated to implement the SDWA establish six classes of injection wells and provide regulations for each class.[3] The original federal UIC regulations recognized five classes of wells—Classes I though V[4]—but Class VI was added in 2010 to regulate wells used to inject carbon dioxide for CCS.[5]

Primacy

Part C of the SDWA[6] 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.

[1] H.R. Rep. No. 93-1185 (1974).
[2] 42 U.S.C. § 300h(a)-(b).
[3] 40 C.F.R. § 144.6.
[4] 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).
[5] 75 Fed. Reg. 77230 (Dec. 10, 2010).
[6] Part C of the SDWA is found at 42 U.S.C. §§ 300h *et seq.*

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.[7]

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.

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.

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

EPA Proposes Granting UIC Primacy to Arizona for Classes I-VI

Keith B. Hall
LSU Law Center

The United States Environmental Protection Agency (EPA) published a proposed rule in the Federal Register on May 19, 2025 to grant 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). *See* Fed. Reg. 21,264 (May 19, 2025). The public comment period closed on July 3, 2025.

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."[1] 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."[2]

Federal regulations promulgated to implement the SDWA establish six classes of injection wells and provide regulations for each class.[3] The original federal UIC regulations recognized five classes of wells—Classes I though V[4]—but Class VI was added in 2010 to regulate wells used to inject carbon dioxide for CCS.[5]

Primacy

Part C of the SDWA[6] 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

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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.

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.

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

Fifth Circuit Affirms Surety Cannot Recover from Former Offshore Lessees for Forfeited Bonds Used to Pay for Decommissioning

Chance Vienne
Liskow

The Fifth Circuit's recent decision in *Lexon Insurance Co., Inc. v. Chevron U.S.A. Inc.*, Docket No. 24-20347 (slip opinion dated 5th Cir. Aug. 19, 2025), 2025 WL 2397624, addresses who should pay offshore decommissioning costs when a current leaseholder fails to meet its legal obligations. Federal law requires that wells, pipelines, and platforms on the Outer Continental Shelf be safely abandoned once operations cease. That obligation runs not only to the current leaseholder and operator, but to all who have ever held such interests.

In this case, Linder Oil was the most recent operator for an offshore lease. But after going bankrupt and defaulting, its surety, Lexon Insurance Company, paid more than $11 million on performance bonds to the government. The government, in turn, transferred that money to former leaseholders, who completed decommissioning. Although the total costs exceeded the amount of the bonds, Lexon nonetheless sought reimbursement from several former leaseholders. By forfeiting the bonds, Lexon argued it paid a debt to the government on behalf of the former leaseholders who were jointly responsible for decommissioning costs. As a result of its payment, Lexon claimed it was entitled to step into the government's shoes and recover its money through "subrogation." Lexon consequently filed suit against the former leaseholders in federal court, alleging its subrogation theory along with theories of contribution and unjust enrichment. But the district judge rejected each of these claims on summary judgment and dismissed Lexon's lawsuit with prejudice. In response, Lexon sought appellate review.

A unanimous three-judge panel of the Fifth Circuit sided with the trial court. Writing for the majority, Judge Irma Ramirez first addressed Lexon's federal-law claims. In seeking subrogation, Lexon relied in large part on 31 U.S.C. § 9309. According to Lexon, this statute allows "a surety" who pays "the government under a bond" to "obtain reimbursement from any party whom the government" could have "lawfully" forced to pay.[1] The panel disagreed with that interpretation. "[C]ontrary to Lexon's argument," the Court ruled, § 9309 is far more limited in scope: "[B]y its plain text and title," the statute simply allows a surety who satisfies a government debt "the same priority as the United States to the insolvent principal's assets and estate."[2] On this basis, the surety may bring "a civil action under the bond" against the principal, but not against third-parties uninvolved with the bond agreement.[3] Because the defendants here were "not parties to the bonds," the

[1] *Lexon*, Slip Op. at 6, 2025 WL 2397624 at *3.
[2] *Lexon*, Slip Op. at 6–7, 2025 WL 2397624 at *3.
[3] *Lexon*, Slip Op. at 7, 2025 WL 2397624 at *3 (quoting 31 U.S.C. § 9309).

court concluded that § 9309's plain text foreclosed Lexon's statutory subrogation argument.[4]

The Court next considered whether Lexon could invoke "equitable subrogation" through "established federal common law."[5] But this theory fared no better. As the statute governing offshore disputes, the Outer Continental Shelf Lands Act mandates that federal law apply. Yet "[w]hen there is a gap to fill in federal law," state law, not judge-made federal rules, supplies the rule of decision.[6] As the Fifth Circuit has recognized, "federal courts should not create interstitial federal common law when the Congress has directed that a whole body of state law shall apply."[7] In this case "no federal statute govern[ed] the precise" subrogation issue, so the panel rejected Lexon's federal common law theory and turned instead to the law of Louisiana.

Ultimately, however, Lexon's subrogation argument found no support in the Civil Code. Although Louisiana recognizes "legal subrogation," the "right is strictly construed."[8] To qualify, the paying obligor must have "recourse" against others who were also bound for the same obligation.[9] Here, the panel concluded that Lexon had shown no such "recourse" against defendants.[10] Between the parties, the relevant regulations and contracts placed the risk squarely on Linder Oil, who expressly agreed to indemnify the others.

For the same reason, Lexon's state law contribution claim failed. As the court explained, contribution presumes a "shared, equal burden" among "co-sureties."[11] In this case, however, Lexon was not a co-surety with defendants; it was Linder Oil's surety alone. And even if the defendants could be styled as "co-sureties," they had secured indemnity from Linder.[12] Such a reality, the Court ruled, "rebutted" any "presumption" of a shared "principal obligation."[13]

Finally, the panel considered Lexon's unjust enrichment claim. But, like the others, this argument was also meritless. A successful unjust enrichment theory requires that the "enrichment" be without legal "justification."[14] Here, the majority recognized that any benefit defendants received was justified by the "indemnity agreements with Linder Oil."[15] Because "equity" had no role in rewriting those valid

[4] *Id*.
[5] *Lexon*, Slip Op. at 7–8, 2025 WL 2397624 at *4.
[6] *Lexon*, Slip Op. at 5, 8, 2025 WL 2397624 at *4.
[7] *Lexon*, Slip Op. at 8, 2025 WL 2397624 at *4 (quoting Matte v. Zapata Offshore Co., 784 F.2d 628, 631 (5th Cir. 1986)).
[8] *Lexon*, Slip Op. at 9, 2025 WL 2397624 at *5 (quoting Martin v. La. Farm Bureau Cas. Ins. Co., 638 So.2d 1067, 1068 (La. 1994)).
[9] *Id*. (quoting La. Civ. Code art. 1829(3)).
[10] *Lexon*, Slip Op. at 9–10, 2025 WL 2397624 at *5.
[11] *Lexon*, Slip Op. at 10–11, 2025 WL 2397624 at *5 (citing La. Civ. Code art. 3055).
[12] *Lexon*, Slip Op. at 11, 2025 WL 2397624 at *5.
[13] *Id*.
[14] *Lexon*, Slip Op. at 11–12, 2025 WL 2397624 at *6 (quoting Edwards v. Conforto, 636 So.2d 901, 907 (La. 1993), on reh'g (May 23, 1994)).
[15] *Lexon*, Slip Op. at 12, 2025 WL 2397624 at *6.

“bargained-for” transactions, the panel affirmed dismissal of Lexon’s unjust enrichment claim.[16]

In the end, Lexon issued bonds to “secure Linder Oil’s decommissioning obligations.”[17] In fulfilling its responsibility as surety, Lexon paid when Linder defaulted. Neither federal nor Louisiana law allowed Lexon to shift that burden to former leaseholders.

This decision reinforces the valuable role performance bonds in favor of the government play in backstopping offshore decommissioning obligations. While the government retains discretion to decide whether to call for the forfeiture of bonds when a lessee or operator defaults on its obligations (unless the bonds are dual-obligee bonds in favor of both the government and a predecessor), when it does so, predecessors who step up to perform decommissioning can accept bond proceeds to help defray the associated costs. This certainty supports reliance by sellers, at least in part, on government bonds in connection with assumption of decommissioning liabilities by purchasers in purchase and sale agreements and related indemnity provisions.

Note: Liskow & Lewis represented defendants Chevron U.S.A Inc. and BP America Production Company. Jana Grauberger and Michael Rubenstein represented the companies at the trial court. Liskow’s appellate team, Kelly Becker and Kathryn Gonski, handled the appeal. Ms. Becker argued for the companies at the United States Fifth Circuit Court of Appeals.

[16] *Lexon*, Slip Op. 11–12, 2025 WL 2397624 at *6.
[17] *Id*. at 12.

Texas Supreme Court Says Production by Co-Tenant Maintained Lease with Passive-Voice Habendum Clause

Keith B. Hall
LSU Law Center

Multiple co-tenants owned fractional interests in the minerals beneath certain land in Loving County, Texas. David Cromwell was the lessee under two oil and gas leases, each granted by one of the co-tenants. Anadarko E&P Onshore, LLC held interests under leases granted by other co-tenants. Cromwell and Anadarko did not enter a joint operating agreement (JOA). Anadarko established production prior to the end of the primary terms of Cromwell's leases. Anadarko and Cromwell disputed whether Anadarko's production maintained Cromwell's leases. The Texas Supreme Court found that Cromwell's leases were maintained.

Background

Anadarko drilled multiple wells and established production on certain land in Loving County. However, Anadarko did not hold the entire working interest, and Cromwell obtained two oil and gas leases covering the same land. Each of the two leases stated that the leases were granted to Cromwell for the purpose of exploring for and producing oil and gas.

Both of Cromwell's leases were paid-up leases. The habendum clause of one of his leases stated:

> This lease . . . shall be in force for a term of three (3) years from this date (called "primary term") and as long thereafter as oil, gas or other minerals are produced from said land, or land with which said land is pooled hereunder, or as long as this lease is continued in effect as otherwise herein provided.

The habendum clause of Cromwell's other lease stated:

> Subject to other provisions contained herein, this lease shall be for a term of five (5) years from the date first above written (hereinafter called the "primary term") and as long thereafter as oil, gas, liquid hydrocarbons or their constituent products, or any of them, is produced in commercial paying quantities from the lands leased hereby.

Shortly after Cromwell acquired his leases, he sent his leases to Anadarko and asked to participate in three wells that Anadarko had already drilled, as well as future wells that Anadarko might drill. Anadarko did not respond to that 2009 communication. Between 2009 and 2018, Cromwell sent Anadarko several other communications about the possibility of entering a joint operating agreement, but Anadarko still did not respond to those communications either.

However, one of Anadarko's wells reached payout in 2009. Although Anadarko had ignored Cromwell's initial 2009 communication, and would ignore his communications in later years about the possibility of entering a joint operating agreement, Anadarko communicated with Cromwell after its well reached payout. Anadarko asked Cromwell to confirm his fractional working interest, and Anadarko sent Cromwell joint interest billings (JIBs) for his share of the costs of the well that had reached payout. Cromwell paid the JIBs. In future months, when revenue from the well exceeded operating costs, Anadarko sent Cromwell his share of the proceeds. For months when expenses exceeded revenue, Anadarko billed Cromwell and he paid his share of the costs. Later, Anadarko sent Cromwell an authorization for expenditure (AFE) that gave Cromwell the opportunity to participate in the costs of a new compressor. Cromwell signed the AFE and later paid his share of the costs.

The primary terms of Cromwell's leases expired in February 2012 and March 2014, but for a time Anadarko continued to treat him as a working interest owner. In 2017, however, Anadarko concluded that Cromwell's leases had terminated. Anadarko then obtained top leases that covered the mineral interests covered by Cromwell's leases. Anadarko later told Cromwell that his leases had terminated.

Cromwell responded by filing suit for a declaratory judgment that his leases had not terminated, and for trespass to try title, as well as other causes of action. Both parties moved for summary judgment regarding whether Cromwell's leases had terminated. The trial court denied Cromwell's motion and granted Anadarko's motion. Cromwell appealed.

The court of appeals affirmed. The court reasoned that Cromwell had to establish production in order to maintain and hold the leases beyond the primary terms by production. It was not sufficient that Anadarko established production. Further, Anadarko's production could not count as production on behalf of both Anadarko and Cromwell. If Anadarko and Cromwell had entered a JOA, with Anadarko as the operator, then Anadarko's production would have been considered as being on behalf of Cromwell too. But they had not entered a JOA. Further, the appellate court reasoned that Cromwell's payment of JIBs and its signing of the AFE were not sufficient to classify Anadarko's production as being on behalf of both Anadarko and Cromwell. The appellate court noted that even non-participating co-tenants are liable for their share of costs, though usually this is "paid" out of the non-participant's share of production, while Cromwell apparently paid at least some of this share of costs out-of-pocket.

Cromwell petitioned the Texas Supreme Court for review and the Court agreed to review the case. The Court noted that the habendum clauses of the two leases used the passive voice in talking about production. One stated that the lease would last as long beyond the primary term "as oil, gas or other minerals are produced," without stating that those substances would have to be produced by the lessee in order to maintain the lease. The other lease stated that it would remain in effect beyond the primary term as long as oil or gas "is produced," likewise not stating that the production had to be by the lessee.

The Court acknowledged that, in *Mattison v. Trotti*, 262 F.2d 339 (5th Cir. 1959), the U.S. Fifth Circuit made an *Erie* guess that, under Texas law, even if a lease contains a passive voice habendum clause that does not state that production must be by the lessee to maintain the lease, it is necessary that production be by the lessee because "the drilling for and the production of oil or gas by the lessee is the [lease's] prime consideration."

Further, a Texas appellate court—the El Paso Court of Appeals—followed *Mattison* in *Hughes v. Cantwell*, 540 S.W.2d 742 (Tex. Civ. App.—El Paso 1976). In that case, an operating co-tenant gave a non-operating co-tenant the opportunity to participate in drilling, and the non-operating co-tenant refused. In those circumstances, the court held that the operating co-tenant's operations were not conducted on behalf of the non-operating co-tenant, and therefore the non-operating co-tenant's lease could not be maintained by production by the operating co-tenant.

Further, the El Paso court extended that rule in *Cimarex Energy Co. v. Anadarko Petroleum Corp.*, 574 S.W.3d 73 (Tex. App.—El Paso 2019). In that case, the non-operating co-tenant paid its share of operating expenses and it offered to enter a JOA with the operating co-tenant, but the operating co-tenant refused the offer. Again, the El Paso court held that the non-operating co-tenant's lease was not held by the operating co-tenant's production of oil and gas.

The Texas Supreme Court rejected those decisions and overruled them. The Court explained that the literal language of the habendum clause in Cromwell's leases provided that the leases would be maintained if there was production. The leases did not state that the production had to be by the lessee. Further, there was production from the leased premises. Thus, the conditions required to maintain the lease beyond the primary term were satisfied. The Court reasoned that it was improper to read into the lease a requirement that was not there, such as the requirement that the production be by the lessee. Moreover, the Court noted that sometimes habendum clauses state that, to maintain a lease by production, it must be the lessee's production. Thus, parties can write their leases to provide that only the lessee's production will maintain the lease, but the parties to Cromwell's leases had not done so.

U.S. Supreme Court Decides Major NEPA Case

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In *Seven County Infrastructure Coalition v. Eagle County*, 145 S. Ct. 1497 (2025), the United States Supreme Court clarified the requirements imposed by the National Environmental Policy Act (NEPA) and the standards for judicial review when a party challenges a federal agency's action, arguing that the agency did not conduct a sufficient environmental impact statement (EIS) under NEPA.

The Court held that, although there are some legal standards for an EIS—such as a requirement that it must be "detailed"—an agency must make some judgments and exercise some discretion in deciding "what details need to be included in any given EIS." If a party challenges, an agency's exercise of discretion in exercising that judgment and discretion, a judicial review typically should be "conducted under the Administrative Procedure Act's deferential arbitrary-and-capricious standard."

The Court also held that, when an agency proposes approval of a project, NEPA does not require an agency to evaluate the indirect effects that project might have on separate projects over which the agency has no control.

Background

In 2020, a group of seven Utah counties proposed the construction and operation of an 88-mile railroad line in northeastern Utah to connect the Uinta Basin to the national railroad network. The proposed project is projected to bring significant economic growth to the Uinta Basin by better connecting it to the national economy. One effect of the proposed railroad line would be to allow the transportation of petroleum from the oil-rich Uinta Basin to refineries in Louisiana and Texas by rail. At present, oil from the Uinta Basin is transported via truck.

Federal law requires new railroad construction to be approved by the U.S. Surface Transportation Board (Board). 49 U.S.C. § 10901. The Board's approval of a new railroad line constitutes a "major Federal action" for purposes of NEPA, which requires an agency to provide a "detailed statement" or EIS before the agency takes "major Federal actions significantly affecting the quality of the human environment." 42 U.S.C. § 4332(C).

The Board issued a draft EIS in October 2020 and invited public comment. The Board held six public meetings regarding the proposed rail line and collected more than 1,900 comments. In August 2021, the Board published its final EIS. The final EIS exceeded 3,600-pages, analyzing in detail various environmental impacts that construction and operation of the proposed rail line might have, such as disruptions to wetlands and land use, and "minor impacts" to air quality and big-game movement in the vicinity of the construction.

The EIS also noted, but did not thoroughly analyze, certain potential indirect effects that the rail line might have. For example, the EIS noted the possibilities that construction and operation of the line might indirectly lead to increased drilling for oil in the Uinta Basin and that the line might lead to refineries in Texas and Louisiana refining more petroleum. The EIS explained that it was not analyzing the potential for increased drilling in the Uinta Basin in detail because the Board has "no authority or control over potential future oil and gas development" in the Basin. Instead, such development is subject to "approval processes of other federal, state, local, and tribal agencies."

As for the possibility of increased refining of petroleum in Texas and Louisiana, the EIS noted that the effect of the proposed line was uncertain because the specific destinations of any Uinta oil shipped by rail "would depend on the ability and willingness of refineries in other markets to receive rail cars carrying Uinta Basin crude oil and process the oil in their refineries." Further, the Board "would have no role in approving or regulating the production, refining, or use" of oil from the Uinta Basin.

In December 2021, the Board approved the construction and operation of the proposed line. Several opponents of the line then filed suit in the U.S. Court of Appeals for the D.C. Circuit, arguing that the EIS was inadequate because it did not provide a detailed evaluation of the potential for increased drilling in the Uinta Basin and increasing refining in Texas and Louisiana. The D.C. Circuit concluded that the EIS was inadequate in several ways, including its failure to include a detailed analysis of the potential for increased upstream drilling and petroleum refining. The Court said that those potential effects were "reasonably foreseeable" and therefore had to be analyzed in detail. The D.C. Circuit then vacated the EIS and the Board's approval of the proposed rail line. Supporters of the line petitioned the U.S. Supreme Court for a writ of certiorari, and the Court granted the writ.

Supreme Court's Analysis

The United States Supreme Court voted unanimously (with Gorsuch not participating) to reverse the decision of the D.C. Circuit. Justice Kavanaugh wrote for a five-judge majority, while Justice Sotomayor wrote a concurring opinion that two other justices joined.

The majority opinion noted that NEPA is a procedural statute. Unlike such statutes as the Clean Air Act and Clean Water Act, NEPA does not impose any substantive rules. Rather, it requires federal agencies to carefully consider and explain potential environmental impacts of any proposed major federal action. This consideration and explanation must include consideration and discussion of reasonable alternative actions, including the alternative of doing nothing.

As a first reason for reversing the D.C. Court's judgment, the Court began by acknowledging that NEPA requires a "detailed" EIS, and what constitutes "detailed" is a legal question that is to be decided de novo by a court in the event of dispute. But an agency must inevitably make some judgment calls on what particular details and issues are to be included in the EIS. The exercise of that judgment is an act of agency discretion that is to be reviewed under the Administrative Procedure Act's deferential arbitrary-and-capricious standard.

One of the decisions that an agency must make is the scope of the environmental review that it will make for the EIS. NEPA requires the agency to evaluate the potential environmental impact of the "proposed action." Accordingly, the agency should consider reasonably possible direct impacts of the proposed action, but the agency must make a judgment call regarding how far it will go in evaluating indirect potential impacts, particularly indirect potential impacts on geographically separate projects over which the agency has no regulatory authority. The majority opinion concluded that the D.C. Circuit did not review the Board's EIS with the deference due under the arbitrary-and-capricious standard.

As a second reason for reversing the D.C. Circuit, the majority concluded that the D.C. Circuit made a mistake regarding what NEPA requires. The D.C. Circuit concluded that, because the possibility of increased drilling in the Uinta Basin and increased refining in Texas and Louisiana were foreseeable, potential impacts of building and constructing the proposed rail line, that NEPA required the Board to analyze these potential impacts in detail. The Supreme Court disagreed. The majority opinion explained:

> [W]hen the effects of an agency action arise from a separate project—for example, a possible future project or one that is geographically distinct from the project at hand—NEPA does not require the agency to evaluate the effects of that separate project.

The Court elaborated that the environmental effects of a particular project may be felt at a location geographically distant from a project—for example, discharges into a river may flow many miles from a project and affect fish at a distant location—and those effects of the proposed project will need to be analyzed. But the possibility that the proposed project may affect the scope or likelihood of a separate project at a distant location does not mean that the EIS for the proposed project must include a detailed analysis of the potential environmental effects of the separate project, even if that separate project is foreseeable. This is particularly true when the agency that is considering the proposed project has no jurisdiction or authority over the potential separate project.

Here, any proposed drilling in the Uinta Basin would be a separate project, and the Board has no authority over any such proposed drilling. Further, petroleum refining would constitute a separate project, and the Board has no authority over refining. Accordingly, the D.C. Circuit erred by holding that the Board's EIS was defective due to its failure to evaluate in more detail the possibility of increased drilling and refining.

The concurring justices would have reversed the D.C. Circuit on narrower grounds. The concurring opinion noted that NEPA is designed to improve agencies' decision-making by ensuring that they consider environmental impacts that might influence their decisions. Consistent with this purpose, existing jurisprudence establishes that NEPA does not require an agency to consider environmental impacts when the agency has no discretion to act on that information. The concurring opinion noted that federal statutes set the standards for the Board to use in deciding whether to approve new lines, and the statutory standards did not seem to include consideration of the environmental effects of transporting a product. Therefore, the Board would not have had discretion to base its decision whether to reject the proposed rail line based on the potential for increased drilling or refining.

5th Circuit Addresses Requirements for "Best Available Control Technology" for Air Pollution PSD Permits under the Federal and Texas Clean Air Acts

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The U.S. Court of Appeals for the Fifth Circuit, in *Port Arthur Community Action Network v. Texas Commission on Environmental Quality*, 2025 WL 2318680 (5th Cir. Aug. 12, 2025) ("*PACAN v. TCEQ*"), issued a decision addressing Prevention of Significant Deterioration permits (a "PSD permit") issued by the Texas Commission on Environmental Quality ("TCEQ"), under the Federal and Texas Clean Air Acts and the Texas' Environmental Protection Agency ("EPA") State Implementation Plan ("SIPs"). The PSD permit at issue involved a new planned natural gas facility in Port Arthur, Texas. In this decision, the Fifth Circuit addressed the novel question as to "whether, under Texas law, 'best available control technology' encompasses air pollution control methods that TCEQ has issued a permit for but are not yet in operation." The Fifth Circuit's decision adopted the reasoning of the Texas Supreme Court and concluded that "Best Available Control Technology" ("BACT") requirement for PSD permits as defined in the Texas Administrative Code only requires that the BACT, through both experience and research, has proven to be operational, obtainable, and capable of reducing emissions. Theoretical proof of a method's operability in the future, but without real-world operational data, is not enough.

Background

Pursuant to Texas' SIP with the EPA, the TCEQ is responsible for enforcing both the Federal Clean Air Act and Texas' state version. Included within this responsibility, the TCEQ is tasked with reviewing and issuing PSD permits "before a 'major stationary source' of pollution is constructed in an EPA attainment area."[1] A "major stationary source" is a facility that has the potential to emit more than 250 tons of a regulated pollutant per year.[2]

To receive a PSD permit, the facility owner or applicant is required to show that the sources of emissions at the facility satisfy BACT.[3] The Texas and Federal regulations require facilities to reduce pollution to the maximum extent (account for cost and other considerations) to satisfy BACT.[4]

[1] 2025 WL 231868, at *1 (citing 40 C.F.R § 52.21(a)(2)(i)).
[2] *See* 40 C.F.R. § 52.21(a)(2)(i).
[3] The requirements under federal and Texas law are the same or show the same level of stringency such that there is no preemption by the Federal law. *See* 2025 WL 2318680, at *5.
[4] *See* 40 C.F.R. § 52.21(b)(12); 30 Tex. Admin. Code §116.10(1).

Port Arthur LNG, L.L.C. ("Port Arthur LNG"), in *PACAN v. TCEQ*, is planning to build a liquefied natural gas plant and export terminal in Port Arthur, Texas. The planned facility has the potential to emit more than the 250 tons of regulated pollutants and therefore constitutes a major stationary source. As such, Port Arthur LNG sought a PSD permit from the TCEQ in 2019. In Port Arthur LNG's application, it proposed for permitting purposes emission rates for its refrigeration turbines of 9 parts per million by volume, dry ("ppmvd") of NOx (nitrogen oxides) and 25 ppmvd of CO (carbon monoxide).

The TCEQ Executive Director in June 2020 issued a preliminary decision and draft permit to Port Arthur LNG along the proposed emission rates in Port Arthur LNG's PSD permit application. A final decision after the public comment period was issued in March 2021 and the TCEQ concluded that the Port Arthur LNG draft PSD permit complied with applicable law and was subsequently referred to the Commission[5] for a public hearing.

The Port Arthur Community Action Network ("PACAN") is a Port Arthur, Texas based community organization focused on environmental justice and advocacy as well as community development in Port Arthur, Texas.[6]

PACAN requested a contested case hearing challenging the TCEQ Executive Director's decision. PACAN challenged multiple aspects of the draft PSD permit, but the critical challenge was whether the proposed emission rates in the draft PSD permit satisfied BACT requirements.

During the contested hearing process, Port Arthur LNG filed certified copies of its application, the TCEQ Executive Director's preliminary decision, and the draft permit. This submission was sufficient to meet the legal requirements that the draft PSD permit satisfied the applicable legal requirements pursuant to the Texas Government Code and relevant substantive statutes. In response PACAN provided a 2020 permit issued by the TCEQ to Rio Grande LNG for a liquid natural gas facility that had been approved but not yet constructed and utilized the same refrigeration techniques proposed for the Port Arthur LNG facility. The Rio Grande LNG permit notably had a decreased NOx and CO emission limit as compared to the Port Arthur LNG draft permit. The Rio Grande LNG permit provided for 5 ppmvd of NOx and 15 ppmvd of CO. The Rio Grande LNG permit also stated that the decreased limits were "consistent with the lowest levels of control for Refrigeration Compressor Turbines; therefore, BACT is satisfied."

Based on Port Arthur LNG and PACAN's submissions, the ALJs issued a Proposal for Decision that agreed with the concerns of PACAN and proposed that

[5] As the Fifth Circuit noted, the "Commission" refers to the adjudicative body that decided Port Arthur LNG's application while the "TCEQ" is the respondent in this case as the governmental agency responsible for issuing PSD permits under the Federal and Texas Clean Air Acts respectively.
[6] *See* https://www.pa-can.com/.

the Commission approve the PSD application subject to amendments that limited Port Arthur LNG's emissions to 5 ppmvd of NOx and 15 ppmvd of CO. In coming to this conclusion, "the ALJs noted that Rio Grande LNG 'utilizes the same [] turbines in refrigerant compressor service' as Port Arthur LNG's proposed project, but that the NOx and CO limits proposed by Port Arthur LNG were higher." The ALJs also noted that Port Arthur LNG had failed to address the Rio Grande LNG facility in its BACT analysis and failed to show why the emission limits in the Rio Grande LNG permit were not BACT for the Port Arthur LNG facility.

The TCEQ Executive Director objected to the ALJs proposed decision on the basis that emission limits in the Rio Grande LNG permit had not been demonstrated in practice because the Rio Grande LNG facility was not yet in operation. Included in the administrative record reviewed by the Fifth Circuit, David Garcia, a permitting staff member with the EPA, explained that the EPA's definition of BACT does not require operational or actual demonstration in practice to be considered technically feasible and BACT.

In September 2022, the Commission held a public hearing rejecting the ALJs proposed amendments and granting Port Arthur LNG's PSD permit at the original requested emission limits of 9 ppmvd of NOx and 25 ppmvd of CO.

PACAN sought an appeal to the Fifth Circuit after its motion for rehearing was overruled by operation of law.

Fifth Circuit's Decision

Standing

The Fifth Circuit decided two separate issues on appeal. The first issue was whether PACAN had standing to challenge the Commission's permit approval as an association. As the Fifth Circuit noted, under the current standard, an association has standing if it can demonstrate that its members have individual standing. In essence, the association must show that its members have suffered (1) an injury, (2) that is traceable to the challenged conduct, and (3) that is likely to be redressed by a favorable judicial decision.[7] The Court concluded that PACAN did have standing based on the standing of its president and founder who submitted a declaration regarding the potential impact on his home, which is four miles from the proposed facility as well as local areas in Port Arthur where he regularly recreates.

Whether Port Arthur LNG's PSD Permit is BACT

On the substantive issue as to whether the Commission erred in approving the Port Arthur LNG PSD permit and allowing higher NOx and CO limits than those approved with respect to the Rio Grande LNG facility, the Fifth Circuit turned to the

[7] 2025 WL 2318680, at *3 (citing *Gill v. Whitford*, 585 U.S. 48, 65 (2018)).

Texas Supreme Court. As the Court noted, the issue turns on whether Rio Grande LNG's emissions limits are BACT under Texas law. The Court certified the following question the Texas Supreme Court:

> Does the phrase "has proven to be operational" in Texas' [] definition of "best available control technology" codified at Section 116.10(1) of the Texas Administrative Code require an air pollution control method to be currently operating under a permit issued by the Texas Commission on Environmental Quality, or does it refer to methods that TCEQ deems to be capable of operating in the future?

The Texas Supreme Court concluded that BACT requires that "the technology itself was 'technically practical,' 'economically reasonable,' 'operational,' 'obtainable,' and 'capable of reducing or eliminating emissions.'"[8] The Texas Supreme Court further noted that the definition of BACT under Texas Administrative Code, requires that the technology "has proven to be operational," which is in perfect-tense. Based on this grammatical structure, the Texas Supreme Court concluded that this then refers to a method that has "*already* proven, through experience and research, to be operational, obtainable, and capable of reducing emissions."[9]

Based on the foregoing construction of the Texas Administrative Code, the Texas Supreme Court rejected the arguments and the basis of PACAN's challenge to Port Arthur LNG's permit because the Rio Grande LNG facility was not yet operational such that the emission and pollution control limits in that permit were anything more than theoretical. Essentially, PACAN did not show real-world operational data for the stricter emission requirements to meet the BACT requirement. The Texas Supreme Court also noted that a permit issued to another facility does not necessarily have bearing on the BACT standards because the issued permit may "reflect technology that controls pollution 'beyond what is currently available, technically practical, and economically reasonable.'"[10]

The Fifth Circuit adopted the Texas Supreme Court's reasoning in its opinion on the Fifth Circuit's certified question and denied PACAN's petition for review of the Commission's decision and award of a PSD permit to the Port Arthur LNG facility.

Based on the Fifth Circuit's adoption of the Texas Supreme Court's reasoning, in Texas at a minimum, BACT with respect to a PSD permit refers only to methods that have proven to be operational as "technically practical," "economically

[8] 2025 WL 2318680, at *4 (quoting *Port Arthur Community Action Network v. Texas Commission on Environmental Quality*, 707 S.W.3d 102, 107 (Tex. 2025)).
[9] *Id.* (quoting 707 S.W.3d at 108).
[10] *Id.* (quoting 707 S.W.3d at 108).

reasonable," "operational," "obtainable," and "capable of reducing or eliminating emissions." Theoretical proof or permits issued to other facilities that are not yet in operation is not enough.

Change to Louisiana Severance Taxes

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Like most states with oil and gas activity, Louisiana imposes severance taxes on the production of oil and natural gas. The Louisiana Legislature amended the severance tax statutes during the 2025 Regular Session.

Reduction in Severance Tax for Oil from New Wells

Louisiana Revised Statute 47:633 governs the severance tax rate. The general severance tax rate on the production of oil has been 12.5% of the value of the oil at the time and place of severance. Acts 2025, No. 295 reduces this to 6.5% of the value of oil at the time and place of severance for wells completed on or after July 1, 2025. The rate of 12.5% is retained for wells completed before July 1, 2025.

Revised Statute 47:633(A)(3)(a) has imposed a lower severance tax rate for oil from wells that can only produce oil at a low rate, with the tax being 6.25% on wells that cannot produce more than 25 barrels per month and 3.125% for wells that cannot produce more than ten barrels per month. The statute also imposed the rate of 3.125% on oil from certain gravity drainage wells and wells brought back into production after having been inactive for two years, if the well is brought back into production before October 1, 2028, or a rate of 6.25% if the well is brought back into production after October 1, 2028. These rates all remain the same, but the language of the portions of Revised Statute 47:633 has changed. The change in language merely states the percentage tax rate directly, instead of stating the rate by reference to the general severance tax rate.

For example, 47:633 previously stated that the severance tax rate for oil from wells that cannot produce more than 25 barrels per month was set at one-half the severance tax rate specified in 47:633(A)(3)(a). Because 47:633(A)(3)(a) imposed a tax rate of 12.5%, this resulted in a 6.25% severance tax rate on oil from wells that cannot produce more than 25 barrels per month. As amended, the subsection that set the severance tax rate for such wells simply states that the rate is 6.25%, rather than describing the rate as a fraction of the rate for wells that are capable of producing at a higher rate.

Duration of Horizontal Well Exemption for Natural Gas is Shortened

Louisiana Revised Statute 47:633 contains an exemption from the severance tax for oil and gas produced from horizontal wells. For both oil and gas produced from horizontal wells, the exemption has been for a period of twenty-four months after the well begins production or until the well reaches payout, whichever occurs first. Acts 2025, No. 284 amends the horizontal well exemption so that the severance tax exemption for natural gas produced from a horizontal well completed after July 1, 2025, will last for eighteen months or until the well reaches payout, whichever occurs first. This legislation does not change the duration of the exemption for oil produced from horizontal wells. Further, it does not change the duration of the exemption for gas produced from wells completed before July 1, 2025.

North Dakota Supreme Court Revives Challenge to CCS Amalgamation (Unitization) Statute

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The Northwest Landowners Association (NWLA), the North Dakota Farm Bureau, Inc. (Farm Bureau), and three other plaintiffs challenged the constitutionality of certain North Dakota statutes, including some relating to carbon capture and sequestration, also known as "carbon capture and storage" or "CCS." The North Dakota Supreme Court addressed these challenges in *Northwest Landowners Association v. North Dakota*, 2025 ND 147, a decision issued on August 28, 2025.

Challenged CCS Statutes

In 2009, North Dakota enacted statutes to govern the underground storage of carbon dioxide, which is the sequestration or storage step of CCS. These statutes are found at Chapter 38-22 of the North Dakota Century Code. The statutes authorize the North Dakota Industrial Commission (NDIC) to enter orders to "amalgamate" pore space interests, *see* N.D.C.C. § 38-22-10, and requires that the CCS operator equitably compensate nonconsenting pore space owners whose interests are amalgamated, *see* N.D.C.C. § 38-22-08. Another statute, N.D.C.C. § 38-22-03, authorizes the NDIC to make exceptions, "for good cause," to the statutory requirements for obtaining a CCS permit.

Other Challenged Statutes

In 2021, North Dakota enacted N.D.C.C. Chapter 38-25, which governs the underground storage of oil and gas. Chapter 38-25 contains a provision that authorizes the NDIC to amalgamate pore spaces for the underground storage of oil or gas, *see* N.D.C.C. § 38-25-08, and a provision requiring the storage operator to equitably compensate nonconsenting pore space owners whose interests are amalgamated, *see* N.D.C.C. § 38-25-05. Chapter 38-25 also contains a provision, N.D.C.C. § 38-25-02, which grants the NDIC the authority to make exceptions to the permitting requirements stated in Chapter 38-25, "if required to comply with applicable federal law."

Other provisions in the North Dakota Century Code authorize entry onto private property for surveys, prior to eminent domain proceedings. *See, e.g.*, N.D.C.C. §§ 24-05-09, 32-15-06.

Trial Court Proceedings

The plaintiffs challenged the CCS amalgamation statute, as well as the amalgamation statute for underground storage of oil and gas. They asserted that amalgamation orders would constitute a taking, because such orders would authorize the permanent placement of fluids into the pore spaces of private property. Thus, an amalgamation order is effectively an exercise of eminent domain.

The North Dakota Constitution gives property owners the right to a judicial determination of issues in an eminent domain proceeding, but the challenged amalgamation orders would give the NDIC the authority to issue amalgamation orders and decide what constitutes equitable compensation for the taking.

The plaintiffs challenged the provisions giving the NDIC the authority to make exceptions to the permitting requirements otherwise set forth in the North Dakota Century Code as an improper delegation of legislative authority to an executive agency.

The plaintiffs challenged the statutes authorizing entry onto property for surveys prior to a condemnation proceeding as being an unconstitutional taking without due process or compensation.

The district court dismissed all claims on summary judgment, holding that each claim was either barred by a statute of limitations or as an unviable facial challenge.

North Dakota Supreme Court's Analysis and Decision

The North Dakota Supreme Court stated that, for a plaintiff to have standing to challenge the constitutionality of a statute, the plaintiff must show that he is prejudiced by the statute and that a decision on the constitutional question is necessary to protect his rights under the constitution.

The North Dakota Supreme Court concluded that the plaintiffs had not demonstrated standing to support their claims that N.D.C.C. § 38-22-03 made an improper delegation of legislature authority by authorizing the NDIC to make exceptions, for good cause, to the permitting requirements stated in N.D.C.C. Chapter 38-22. The Court noted that the plaintiffs had not alleged that the NDIC had ever used that authority or that the plaintiffs were ever injured by such an exception. Further, the record contained an affidavit from an NDIC representative, stating that no permit applicant had ever asked the NDIC to make an exception to the permitting requirements stated in in Chapter 38-22.

Similarly, the Court concluded that the plaintiffs lacked standing to challenge the statutes in N.D.C.C. Chapter 38-25 that they claimed were improper. No plaintiff alleged that they own pore spaces subject to an order authorizing amalgamation for the storage of oil or gas. Further, the record contained an affidavit stating that the NDIC has never issued an order amalgamating pore space rights for oil and gas storage.

The Court also addressed the plaintiffs' challenge to the statutes authorizing entry onto property to conduct surveys. The trial court had dismissed those claims, concluding that they were time-barred under the applicable six-year statute of limitations. The trial court reached this decision based on the reasoning that the plaintiffs were making a facial challenge to the statutes. Thus, reasoned the trial court, the statute of limitations began to run when the statute was enacted. The Supreme Court disagreed. The Supreme Court stated that a facial challenge to a statute that allegedly constitutes a regulatory taking must be brought within six years of enactment of the statute because the enactment of the statute itself imposes the rule that allegedly constitutes a regulatory taking. However, a claim for an alleged physical taking accrues when the physical invasion of property occurs. Thus, the trial court erred in concluding that the plaintiffs' claim was time-barred because it was not brought within six years of the passage of the challenged statutes.

However, the Court noted that the takings claim based on the statutes authorizing entry onto property for surveys was not viable for another reason. In particular, while the plaintiffs' claim was pending, North Dakota decided in another case that such statutes are not unconstitutional. In *SCS Carbon Transp. LLC v. Malloy*, 7 N.W.3d 268 (N.D. 2024), the Court concluded that statutes authorizing pre-condemnation entry for surveys is a "longstanding background restriction" on property rights, so that "Landowners cannot demonstrate that they have a constitutionally protected interest in excluding limited, innocuous intrusion by pre-condemnation surveyors."

Finally, the North Dakota Supreme Court addressed the plaintiffs' claim that the CCS amalgamation statute is unconstitutional because an amalgamation order effectively is an order for eminent domain that is issued by a regulatory agency, while the North Dakota Constitution gives property owners the right to a court proceeding in a condemnation case. The district court dismissed this claim, reasoning that it was time-barred because the six-year statute of limitations had run. This conclusion was based on the trial court's reasoning that the plaintiffs were bringing a facial challenge and therefore that the statute of limitations started running when the legislation was enacted, more than six years before the plaintiffs asserted their claim.

The North Dakota Supreme Court disagreed. It acknowledged that, in some cases, a plaintiff claims that the mere enactment of a statute constitutes a taking. For an example, the Court pointed to a statute that purported to give oil and gas companies a right to use pore spaces for waste disposal without the consent of landowners and without compensating them. The Court reasoned that the statute purported to take away the pore space owners' right of exclusive possession.

However, the mere enactment of the amalgamation statute did not strip landowners of any rights, even under the plaintiffs' theory. Instead, reasoned the Court, it would be an amalgamation order that constituted a taking under the logic of the plaintiffs' claim. Thus, the statute of limitations would not start running until an amalgamation order had been entered. Further, at least one of the members of each of the two organization plaintiffs were nonconsenting pore space owners who owned land subject to a CCS amalgamation order. Accordingly, those plaintiffs had standing and their claims were not time-barred. Thus, the trial court erred by failing to reach the merits of the plaintiffs' claim that the amalgamation orders are unconstitutional. The Supreme Court remanded the case to the district court, instructing it to issue a decision on the merits.

The North Dakota Supreme Court noted that one of the defendants had raised a defense that the defendant characterized as being a jurisdictional challenge, but which the Court said was really a claim that federal law preempts the North Dakota courts from hearing the plaintiffs' claims. The Court rejected that defendant's argument. The Court noted that the same defendant argued that the plaintiffs' claims should be dismissed because they had failed to exhaust administrative remedies. The Court disagreed, stating that the exhaustion of administrative remedies doctrine does not apply to the plaintiffs' claim because the NDIC lacks authority to adjudicate the constitutionality of the challenged North Dakota statutes.

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