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Alabama Enacts CCS Legislation

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In its Regular Session during 2024, the Alabama Legislature enacted H.B. 327, which became Act 2024-325. The Act establishes a statutory framework for the carbon dioxide storage operations associated with capture and storage (CCS). The legislation went into effect on October 1, 2024, and is codified at Alabama Code §§ 9-17-160 through 9-17-166.

The legislation states that subsurface pore spaces are owned by the surface owner, absent a severance (including a past severance) of pore space rights from the surface estate.[1] It further provides that a conveyance of the surface estate includes pore space rights, unless the ownership of pore space rights has been expressly reserved in the conveyance (or the pore space rights were previously severed).[2] The legislation provides that no prior conveyance or reservation of oil and gas or other mineral rights includes ownership of pore space rights, unless pore space rights were explicitly included in the transfer.[3] And future conveyances or reservations of oil and gas or other mineral rights that attempt to also include a conveyance or reservation of pore space rights in the same instrument will be void.[4] Thus, a future conveyance or reservation of pore space rights must be in a separate instrument than a conveyance or reservation of mineral rights.

A separate section of the legislation requires a prospective storage operator to make a good faith effort to obtain the consent of all persons who own storage rights for the pore spaces that would be used by the operator's CCS project.[5] To proceed with a CCS project, the prospective CCS operator must obtain consent from persons who own at least two-thirds of the pores spaces to be used.[6] If a storage operator obtains the consent of persons owning at least two-thirds of the pore spaces, the Alabama Oil and Gas Board may issue, after notice and a public hearing, "an order to amalgamate and pool the pore space" and carbon dioxide storage rights owned by nonconsenting persons.[7] The order must provide for nonconsenting owners to be "fairly and equitably compensated."[8]

[1] Ala. Code § 9-17-161(a). Alabama Code § 9-17-160 defines "pore space" for purposes of the CCS statutes. It states: "For the purposes of this division, the term "pore space" means subsurface space that can be used for the geologic storage or sequestration of carbon dioxide and incidental substances that are part of the carbon dioxide capture, transportation, or storage process."
[2] Ala. Code § 9-17-161(b).
[3] Ala. Code § 9-17-161(c).
[4] Ala. Code § 9-17-161(d).
[5] Ala. Code § 9-17-162(2).
[6] Ala. Code § 9-17-162(3).
[7] Ala. Code § 9-17-162(4).
[8] Ala. Code § 9-17-162(5).

Another section establishes an "Underground Carbon Dioxide Storage Facility Administrative Fund," into which will be deposited all administrative fees that the Oil & Gas Board establishes.[9] This Fund is to be used for defraying expenses incurred by the Board in performing its administrative and regulatory duties relating to the geologic storage of carbon dioxide.[10] The same section of the legislation also establishes a separate "Underground Carbon Dioxide Storage Facility Trust Fund."[11] This second Fund is also to be funded by fees levied by the Board on CCS projects.[12] The second Fund is to be used to pay the Board's cost of monitoring and managing a CCS storage facility after ownership has been turned over to the State (more about this below).[13]

Yet another section of the legislation provides that the storage operator has title to all the carbon dioxide injected and stored in a facility (at least until ownership is transferred to the State), and that the storage operator is liable for any damages "attributed to its operations while holding title to the injected carbon dioxide."[14] This section provides that the Board may issue a "certificate of project closure and completion," after notice and a public hearing, if at least ten years has passed from the last date that carbon dioxide was injected, the storage facility is in compliance with all governing laws and regulations, the storage facility is reasonably expected to retain the carbon dioxide, the carbon dioxide plume is stable (meaning it is "essentially stationary" or is not likely to migrate beyond the underground storage reservoir boundary), all wells, equipment, and other facilities are in good condition and retain mechanical integrity, all injection wells have been plugged, all equipment not necessary for long-term monitoring has been removed, and all reclamation work required by the Board has been completed.[15]

After the Board issues a certificate of project closure and completion, ownership of all equipment and facilities needed for long-term monitoring, as well as ownership of the injected carbon dioxide, transfers to the State, along with liability for long-term monitoring.[16] At this point, the storge operator and all persons that generated carbon dioxide stored in the facility are "released from all regulatory requirements associated with the storage facility,"[17] and the storage operator is released from all bond and financial security it may have posted.[18]

Finally, the legislation authorizes the Commissioner of Conservation and Natural Resources to lease pore space rights under the jurisdiction of the

[9] Ala. Code § 9-17-163(a)(1).
[10] Ala. Code § 9-17-163(a)(2).
[11] Ala. Code § 9-17-163(b)(1).
[12] Ala. Code § 9-17-163(b)(2).
[13] Ala. Code § 9-17-163(b)(2).
[14] Ala. Code § 9-17-164(a).
[15] Ala. Code § 9-17-164(b), (c).
[16] Ala. Code § 9-17-164(d)(1).
[17] Ala. Code § 9-17-164(d)(2).
[18] Ala. Code § 9-17-164(d)(3).

Department,[19] and authorizes the Oil and Gas Board to adopt regulations to implement the CCS legislation.[20]

[19] Ala. Code § 9-17-165.
[20] Ala. Code § 9-17-166.

Colorado Enacts CCS Legislation

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During its 2024 Regular Session, the Colorado Legislature enacted carbon capture and storage (CCS) legislation. The legislation was HB24-1346, and this legislation was later signed into law by Governor Jared Polis.

The legislation provides that carbon dioxide injected into the subsurface for CCS remains the property of the person who injected it, unless the person who injected it conveys ownership to someone else. In addition, the legislation provides that ownership of subsurface pore spaces rests with the owner of the surface estate, assuming the pore spaces have not been severed from the surface estate. The legislation states that ownership of pore spaces can be severed from surface ownership, but that a conveyance of the surface includes a conveyance of subsurface pore spaces unless the pore spaces are expressly reserved in the conveyance or the pore spaces were previously severed from surface ownership.

The legislation declares that the "sequestration estate" may be severed from the surface estate "in the same manner as ownership of a mineral estate." However, the conveyance or reservation of the mineral estate does not include the sequestration estate unless the deed that contains the mineral reservation expressly provides for a conveyance or reservation of sequestration rights.

HB24-1346 authorizes Colorado's Energy and Carbon Management Commission to enter an order creating a geologic storage unit for CCS, if the Commission "finds that the geologic storage unit is reasonably necessary to effectuate a geologic storage project." However, an order creating a geologic storage unit is not effective unless the unit plan has been approved in writing by persons who own at least 75% of the geologic storage unit. The legislation does not authorize the use of eminent domain to obtain pore space rights.

A unit order must include a plan of operations and a determination of the percentage of the storage unit to be allocated to each separately owned tract in the unit. The order also must describe the method to be used to allocate compensation to the owners of separate tracts, and must describe how costs will be allocated and paid.

Much of the legislation is codified at Colorado Revised Statutes §§ 34-60-140 through 34-60-143, though other provisions, including definitions and provisions relating to the authority of the Commission, are codified in revisions to other sections of Title 34, Article 60.

Louisiana Legislation Regarding Orphan Wells and State Leasing

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Revisions to Louisiana Oilfield Site Restoration Law

In the Third Special Session of 2024, the Louisiana Legislature enacted revisions to the Louisiana Oilfield Site Restoration Law (La. Rev. Stat. 30:81, *et seq.*) by adopting House Bill No. 23. Governor Jeff Landry then signed the legislation into law as Act 16 of the Third Special Session.

The Louisiana Oilfield Site Restoration Law establishes procedures for the restoration of *orphaned* and *unusable* oilfield sites and establishes rules relating to funding the remediation of such sites. An oilfield site may be declared "orphaned" where (1) it has no continued useful purpose for oil and gas exploration, production, and development; (2) the site was not closed or maintained in accordance with law or it constitutes a danger or potential danger to public health, the environment, or an oil and gas formation; and (3) no responsible party can be located, or such party has failed or is financially unable to restore the site. La. Rev. Stats. §§ 30:82, 30:91.

An oilfield site may be declared "unusable" if a responsible party can be located but (1) the site has no continued useful purposes for the exploration, production, or development of oil or gas; and (2) the responsible party fails to undertake site restoration. La. Rev. Stats. §§ 30:82, 30:89. Once an oilfield site is declared orphaned or unusable, the Commissioner may enter contracts and expend funds to plug and abandon wells, close pits, remove oilfield equipment, and perform other site remediation and restoration. La. Rev. Stats. §§ 30:84, 30:86, 30:89, 30:92, 30:93.

The Oilfield Site Restoration Committee ("OSR"), consisting of ten members, is granted authority to administer the Oilfield Site Restoration Fund and to oversee site-specific trust accounts. La. Rev. Stat. § 30:83. The oilfield site restoration fees consist of (1) 1 ½ cents for each barrel of crude oil produced in the state if the price of oil is at or below $60 per barrel, 3 cents per barrel if the price of oil is above $60 but not above $90 per barrel, and 4 ½ cents if the price of oil is above $90 per barrel, and (2) a fee on natural gas produced in the state in the amount of 3/10 of one cent for each thousand cubic feet with special rules governing stripper wells and incapable wells. La. Rev. Stat. § 30:87.

Act 16 of the Third Special Session creates a new governing body to oversee the Oilfield Site Restoration Fund and site-specific trust accounts and increases the fees for oil and natural gas production. First, the bill replaces the OSR with a Natural Resources Trust Authority to administer funds, with oversight by the State Mineral and Energy Board, and to perform functions traditionally afforded to the Commission. This includes setting priorities for annual site restoration, pledging revenues and securing bonds, approving contractors to conduct assessments and restoration, approving cooperative endeavor agreements, reviewing site restoration activities and assessments, administering and managing the fund and all site-specific trust accounts, and performing other functions authorized by law.

In addition, Act 16 increases the fees under La. Rev. Stat. § 30:87. For crude oil produced in the state, the fee is increased to 2 cents per barrel if the price of oil is at or below $60, 4 cents per barrel if the price of oil is above $60 and at or below $90, and 6 cents per barrel if the price of oil is above $90. For natural gas, the fee is increased to 3/10 of one cent per thousand cubic feet if the price of gas is at or below $2.50 per thousand cubic feet, 4/10 of one cent per thousand cubic feet if the price of gas is above $2.50 and at or below $4.50 per thousand cubic feet, and 5/10 of one cent per thousand cubic feet if the price of gas is above $4.50 per thousand cubic feet.

Revisions to State Property Leasing Laws

In its Third Special Session of 2024, the Louisiana Legislature also approved House Bill No. 24, expanding the powers of the State Mineral Energy Board pursuant to La. Rev. Stat. 30:121, *et seq.*, and revising existing provisions and enacting new laws related to the leasing of state property for energy-related purposes. Governor Landry signed the legislation, which became Act No. 17 of the Third Special Session.

Act 17 allows the State Mineral and Energy Board to lease state lands "for the development and production of minerals, oil, gas, or alternative energy sources and for the purposes set forth in R.S. 30:148.2" and makes clear that payments to the state are a tax, as opposed to rent, for purposes of the U.S. Bankruptcy Code, particularly 11 U.S.C. § 503. This is intended to allow the State to recover those expenses as "administrative expenses" in a bankruptcy, pursuant to 11 U.S.C. § 503.

Act 17 also provides that no mineral lease shall contain more than 5,000 acres, and no solar energy lease shall exceed 35 acres, unless the Senate and House Committees approve a larger acreage (up to 5,000 acres) for the solar lease.

In addition, Act 17 increases fees collected by the State Mineral and Energy Board and the Office of Mineral Resources to reflect agency costs. The mineral board may charge a $175 fee to cover transfer/assignment costs and a $100 fee for lease applications. Additionally, 25% of revenues collected from any operating agreement must be credited to the Mineral and Energy Operation Fund.

Finally, Act 17 revises § 30:129 to clarify that Pugh clauses are required for mineral leases (but not other leases) granted by the Board pursuant to § 30:129.

Use of Eminent Domain Under Natural Gas Act

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Trunkline Gas Co., LLC v. Beissel, 2024 WL 4710377 (W.D. La.), is a recent case that provides a primer regarding the use of eminent domain under the Natural Gas Act, 15 U.S.C. §§ 717 *et seq.*

The Natural Gas Act was enacted in 1938, in response to a United States Supreme Court decision holding that the Commerce Clause of the United States Constitution prevented individual states from regulating interstate natural gas transactions, and the lack, at that time, of any federal regulation of interstate natural gas transactions.

Under 15 U.S.C. § 717f(h), if a person who holds a certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission[1] (FERC) cannot obtain the land or rights-of-way needed to construct, maintain, and operate a natural gas pipeline, as well as the necessary compressor stations and other facilities, can acquire the necessary land or rights-of-way "by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located," or in state court. To exercise the right of eminent domain under the Natural Gas Act, the moving party must show that (1) it holds a certificate of public convenience and necessity from FERC for the construction and operation of a natural gas pipeline, (2) the land or right-of-way sought is necessary for operation of the pipeline, and (3) movant is unable to reach an agreement with the owner of the property regarding price.

In this case, Trunkline holds a certificate of public convenience and necessity from FERC to operate a natural gas pipeline that crosses a portion of the defendant's property. Trunkline held a lease, but the lease would soon expire. Trunkline sought to purchase rights necessary to continue using the surface of the defendant's property to maintain and operate the pipeline, but Trunkline and the defendant were not able to reach an agreement regarding the price for Trunkline to acquire the rights to continue using the land. Trunkline responded by filing an action in federal court, pursuant to the Natural Gas Act and Federal Rule of Civil Procedure 71.1, which provides the procedure for the exercise of eminent domain in federal court.

Trunkline proved that it held a certificate of public convenience and necessity from FERC for the pipeline, that the property rights it sought were necessary for operation of the pipeline, and that Trunkline and the landowner had

[1] The Federal Power Commission was initially given the authority to regulate interstate natural gas transportation and sales, but the Federal Energy Regulatory Commission later replaced the Federal Power Commission.

negotiated, but were unable to reach an agreement regarding the price for Trunkline to obtain the right to continue using the land. Trunkline also presented the court with an independent appraisal of the property to show the value of the rights it sought. Accordingly, the court concluded that Trunkline had shown that it was entitled to use eminent domain.

The court noted that, once a court determines that a company has the right to condemn property using the eminent domain powers granted by the Natural Gas Act, a court may issue a preliminary injunction granting the company immediate possession of the property if it shows: (1) a substantial likelihood of success on the merits; (2) a substantial threat of irreparable injury if the injunction is not issue; (3) that the threatened injury if the injunction is denied outweighs any harm that will result if the injunction is granted; and (4) an injunction will not disservice the public interest.

Here, the court noted that Trunkline already had shown that it is entitled to exercise the right of eminent domain, so the company has shown a substantial likelihood of success on the merits. Further, Trunkline had shown a substantial likelihood of irreparable injury to itself and its customers if the company did not have access to the land to ensure safe and reliable operation of the existing pipeline that already was in operation. There was no showing of significant harm that would result from granting the injunction, and there was no showing that the injunction would disservice the public interest. Therefore, in addition to holding that Trunkline could acquire the rights it sought via eminent domain, the court held that Trunkline was entitled to a preliminary injunction granting it immediate access to the property.

Court Resolves Louisiana Well Cost Reporting Statute Dispute

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In *Mistretta v. Hilcorp Energy Co.*, 2024 WL 4447330 (La. App. 3rd Cir. 2024), the issue was whether the Louisiana Well Cost Reporting Statute's penalty provision applied, and this in turn depended on whether a unit operator is required to send well cost reports to all unleased owners or only to unleased owners who make a written request via certified mail for those reports.

Background

Louisiana statutes authorize its oil and gas regulator—the Office of Conservation—to issue orders that create drilling units and pool the separately owned mineral interests in the unit.[1] The statutes do not specify how production and costs are to be allocated, but the Office of Conservation's pooling orders invariably allocate shares of production and costs to the various tracts on a surface acreage basis.

However, the fact that pooling orders provide for allocating costs on a surface acreage basis does not mean that mineral owners in the unit must "participate" in the risks and costs of drilling. Neither mineral lessees nor the owners of unleased mineral interests—such as landowners and mineral servitude owners whose interests are not subject to a mineral lease—are required to participate in the risks and upfront costs of drilling.

Under Louisiana Revised Statute 30:10, if the unit operator sends a risk charge notice to mineral lessees that provides details regarding a planned unit operation, those lessees are not required to participate in the risks and upfront costs of drilling, but they are subject to a risk charge if they do not agree to participate. That is, they will only be responsible for "paying" their share of costs out of production (so they do not have to pay anything upfront and they do not have to pay any out-of-pocket costs if the well never reaches payout), but they will be liable for "paying" both their share of costs and also an additional "risk charge" from their share of production.

In contrast, the owners of unleased interests are not subject to the risk charge. If the owner of an unleased interest chooses not to participate, that owner is treated as a carried interest. That is, the unleased owner is responsible for its share of costs, but only from its share of production. Thus, the unleased owner does not pay anything out of pocket and does not receive any share of revenue

[1] Louisiana Revised Statute 30:9 authorizes the Commissioner of Conservation to create drilling units and Louisiana Revised Statute 30:10 authorizes the Commissioner to pool the separately owned interests in a unit, if the owners have not already entered a voluntary pooling agreement.

until the unit well reaches payout. But after the cumulative revenue from the unit well is sufficient to cover the costs of drilling, equipping, and operating the well, the unleased owner receives the share of net revenue (subsequent gross revenue minus subsequent costs) allocated to that owner's tract.

But how is such an unleased owner going to know when the well reaches payout? How, for example, can the unleased owner learn the costs of drilling and operating the well, and how can the unleased owner learn the amount of revenue that has been generated by production?

The Well Cost Reporting Statute

Louisiana Revised Statute 30:103.1 gives the unleased owner the right to information regarding the costs of drilling, equipping, and operating a unit well, as well as a right to information regarding production volumes and revenue. This statute is not a model of clarity. Subsection "A" states that the operation "shall issue" reports to the owners of mineral interests that are not under lease to the operator, and also lists information that must be contained in those reports, and specifies a deadline for sending the reports. Read alone, subsection "A" would seem to suggest that the operator must send the reports to all unleased owners, whether or not those persons have requested the reports, but subsection "A" does not specify a means of delivering those reports. But subsection "C" states that the operator must send the reports via certified mail to each owner of an unleased mineral interest that has made a written request, by certified mail, for such reports.

So, which is it? Is the operator required to send the reports to all unleased owners, even those who have not requested reports? Or, is the operator only required to send the reports (via certified mail) to the unleased owners who have submitted (via certified mail) a request for reports? Or, should a court reconcile subsections "A" and "C" by concluding that the operator must send the reports to all unleased mineral owners (even those who have requested the reports), without a particular mode of delivery being required, but if a particular unleased owner has made a written request (via certified mail) for reports, the operator must deliver the report to that unleased owner via certified mail? The Louisiana Supreme Court has not answered this question, but federal courts and state appellate courts have concluded that an operator is only required to send the reports to unleased owners who make a written request via certified mail.

A companion statute to Louisiana Revised Statute 30:103.1 is 30:103.2. This companion statute provides for the possibility of a penalty for operators who fail to comply with their obligations to send reports as required by 30:103.1. The penalty applies if an operator (1) fails to send reports as required by 30:103.1, and (2) the operator subsequently does not correct that failure within 30 days after receiving a written notice from the unleased owner, by certified mail, informing the operator of the failure to timely send reports as required. The penalty is that the operator forfeits its right to deduct the unleased owner's share of costs from the unleased owner's share of production. Thus, the operator becomes obligated to pay the unleased owner a share of the gross revenue, rather than a share of the net revenue.

This Dispute

In *Mistretta v. Hilcorp Energy Co.*, 2024 WL 4447330 (La. App. 3rd Cir. 2024), an unleased owner asserted that the penalty provided by Revised Statute 30:103.2 applied, but the operator disputed this on the basis that the unleased owner had sent one letter by certified mail, and that single letter could not constitute both the request for reports and the subsequent notice that the operator had not sent the requested reports. In other words, an initial written request is required before a duty to send reports under 30:103.1 arises, and then no penalty is owed unless the operator fails to timely send the requested reports and the operator does not correct that failure within 30 days after receiving a subsequent written notice of its failure to timely send the requested reports. The operator's argument is sound if the duty to send reports does not arise until an unleased owner makes a written request for reports.

However, if the operator is required to send reports to all unleased owners, even those who have not requested them, the operator's argument is not sound. In such a case, the operator would have breached its duty to send reports as required by 30:103.1 simply by not sending reports to an unleased owner within the deadlines stated in the statute. Then, a single letter from an unleased owner, sent by certified mail and pointing out that the operator had not yet sent reports, could start the clock on the 30-day period for correcting the failure to send the required reports.

In this case, the Louisiana Third Circuit, like other courts before it, concluded that the operator is only required to send reports to unleased owners who make a written request by certified mail. Here, the unleased owner had sent just one letter. Because that single letter could qualify as both the request for reports and also the notice that the requested reports had not been sent, the Louisiana Revised Statute 30:103.2 penalty did not apply.

Ohio Appellate Court Rejects Arguments that Royalty Interest is Preserved Under “Specific Reference” or “Title Transaction” Exceptions to MTA

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Recently, in *RL Clark, LLC v. Hammond*, 2024-Ohio-5051, Ohio’s Seventh District Court of Appeals rejected the Appellant’s claims that its severed 1/2 oil and gas royalty interest was preserved under the “specific reference” and/or “title transaction” exceptions to Ohio’s Marketable Title Act, R.C. §5301.47, et seq. (MTA).

As background, in 1902, the Wises conveyed 21 acres in Belmont County, Ohio, “excepting the one half (1/2) of the oil and gas royalty” (Wise Royalty). The Appellants are the purported successors in interest to the Wise Royalty and the Appellees are the current surface owners of 8 of the original 21 acres burdened by the Wise Royalty. In 2015, the Appellee, RL Clark, LLC, acquired a 34.09% interest in the oil and gas rights to the 8 acres. Later, in 2021, the Appellee filed a lawsuit against 107 defendants, including the Appellants, seeking to quiet title to the Wise Royalty and obtain a declaratory judgment vesting the Appellee with its 34.09% interest free and clear of the Wise Royalty. The trial court ruled that the Wise Royalty was extinguished under the MTA and quieted title in favor of the Appellee. On appeal, the Appellants argued that the trial court erred in holding that (1) the root of title and subsequent conveyances contain only a “general reference”; (2) the numerous oil and gas leases on the property are not title transactions preventing the MTA from extinguishing the Wise Royalty; and (3) the 1956 deed found to be the Appellee’s root of title is a proper root of title.

“General Reference” vs. “Specific Reference”

In *Blackstone*,[1] the Ohio Supreme Court created a three-step inquiry for determining whether a reference is general or specific: (1) Is there an interest described within the chain of title? (2) If so, is the reference to that interest a “general reference”? (3) If the answers to the first two questions are yes, does the general reference contain a specific identification of a recorded title transaction? If the reference is found to be specific or the general reference contains a specific identification of a recorded title transaction, the interest is preserved under the MTA. The court of appeals determined that the Appellee’s root of title is a 1956 deed that includes the following language: “subject also to such interest in the oil and gas royalties as have heretofore been reserved by former grantors.” The court of appeals answered “yes” to steps one and two of the *Blackstone* inquiry, finding that the root of title contains a reference to a prior mineral interest and the reference is “general.” However, the court of appeals answered “no” to step three of the *Blackstone* inquiry, stating “it is obvious that there is no specific identification of any other recorded instrument.” Rather, the court of appeals described the reference in the root of title and later deeds as “boilerplate, generic, vague, and different than the original description of the property interest.”

[1] 2018-Ohio-4959.

The court of appeals also rejected the Appellant's claim that the facts of this case align closely with its recent decision in *Wolfe v. Bounty Minerals, LLC.*[2] In *Wolfe*, the severed interest at issue was created in 1921 and the root of title was a 1966 deed that did not name the owner of the severed interest, cite the volume and page of the severance deed, or contain a verbatim restatement of the original reservation. However, the parties did not dispute that the severance language was repeated verbatim in subsequent conveyances filed in 1924, 1930, 1940, and 1950. Furthermore, the 1966 root of title deed stated it was subject to the "exceptions, reservations, and conditions" stated in the Exhibit A attached to the root of title, which specifically identified the 1950 deed by date, volume and page number, and name of the grantor and grantee. The court of appeals held that the severed interest was preserved by the specific reference in the 1950 deed, which could be found through the specific information provided in the 1966 root of title. Here, the court of appeals noted that its decision in *Wolfe* did not aid the Appellants' argument because, unlike *Wolfe*, it was apparent from the record that the general reference included in the Appellee's 1956 root of title does not contain a reference to any prior recorded title transaction.

"Mere Existence of Leases" Does Not Preserve Royalty Interest

Next, the Appellants argued that the Wise Royalty was preserved under the "title transaction" exception to the MTA by way of six oil and gas leases recorded within the 40 year period following the 1956 root of title. However, because none of the leases contained any description of the Wise Royalty, the court of appeals determined that there was no connection between the Wise Royalty and the recorded leases cited in the Appellant's brief. The court of appeals found that, aside from the "mere existence of the leases," the Appellants did not show that the Wise Royalty could be found by looking at any of the leases. Moreover, the court of appeals cited its previous decision in *White Revocable Tr. v. Kemp*,[3] where it held that "[i]f a party is trying to prove that a non-participating royalty interest is preserved in the chain of title, a description of that interest must appear in the recorded documents." Therefore, because none of the leases contained a description of the Wise Royalty, the court of appeals held that the Wise Royalty did not "arise out of" the leases and, as a result, the leases did not preserve the Wise Royalty under the "title transaction" exception to the MTA.

Proper Root of Title Argument

Lastly, the Appellants argued that a 1974 deed should have been the Appellee's root of title because it is the deed filed closest to 40 years prior to the filing of the complaint in 2021. Citing its prior decision in *Senterra Ltd v. Winland*,[4] the court of appeals explained that the "root of title" contains "temporal" and "substantive" elements. The temporal element first looks back at least 40 years and then looks forward to find 40 years of unbroken title clear of any preservation act. If a preservation act is found in the succeeding 40 year period, the claimant must look

[2] 2024-Ohio-2460.
[3] 2023-Ohio-4513, 33.
[4] 2019-Ohio-5458.

to a prior title transaction and, if necessary, continue the process until there is a 40 year period of unbroken title clear of any preservation act. The substantive element requires the root of title to purport to create the interest claimed "upon which [the claimant] relies as a basis for the marketability of his title."[5] The court of appeals noted that, in addition to the 1956 deed, the record included conveyances in 1972 and 1974. However, because the 1956 deed is the deed that first omits or extinguishes the Wise Royalty, the court of appeals held that only the 1956 deed satisfied the "substantive" element. The court of appeals explained that, despite finding the 1974 deed contained a general reference, the Appellee could not rely on the 1974 deed for its root of title because it mentions the recorded 1972 deed. Likewise, despite finding the 1972 deed contained a general reference, the court of appeals concluded that the Appellee could not rely on the 1972 deed for its root of title because it mentions the recorded 1956 deed.

Conclusion

The court of appeals overruled each part of the Appellants' sole assignment of error and affirmed the trial court's judgment that (1) the Wise Royalty is not preserved under the "specific reference" exception because the root of title and subsequent conveyances contain only a "general reference" with no specific identification of a recorded title transaction; (2) the oil and gas leases cited by the Appellants are not "title transactions" preventing the MTA from extinguishing the Wise Royalty because there is no connection between the leases and the Wise Royalty; and (3) the 1956 deed is the mostly recently recorded deed in the Appellee's chain of title that satisfies the "temporal" and "substantive" elements of a root of title.

[5] *Id.* at ¶ 53, citing R.C. 5301.47(E).

Maine Sues Oil & Gas Companies Over Climate Change

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On November 26, 2024, the Attorney General of Maine filed suit on behalf of the State against the American Petroleum Institute and several major oil companies in *Maine v. BP P.L.C., et al.* The suit was filed in a state court, the Maine Superior Court, Cumberland County. The oil and gas company defendants are five BP entities, two Chevron entities, two Exxon entities, four Shell entities, and Sunoco LP.

The 193-page petition alleges that various defendants knew about the risk of climate change from the use of fossil fuels by the 1950s and 1960s. In fact, the petition contains allegations about defendants distributing information about climate change. But later, alleges the petition, the defendants began to downplay, ignore, or deny the risk of climate change. Moreover, the defendants continued to sell and promote the use of fossil fuels. The petition alleges that the State of Maine has incurred, and will continue to incur damages caused by climate change, and also will incur costs to respond to climate change. Further, the petition alleges that climate change is caused by using fossil fuels.

The petition purports to assert the following eight causes of action:

1. Negligence (against all defendants) for allegedly engaging in deception regarding the risks of climate change (the petition characterizes the deception as evidencing a lack of due care),
2. Public nuisance (against all defendants) for allegedly causing climate-related harms that are "injurious to health,"
3. Private nuisance (against all defendants) for allegedly causing climate-related harms that interfere with the use and enjoyment of State property,
4. Common law trespass (against all defendants) for allegedly causing additional precipitation, flooding, and sea level rise, thereby causing water to invade state properties,
5. Civil aiding and abetting (against API) for assisting the oil and gas company defendants in committing the alleged torts asserted as causes of action 1 through 4,
6. Statutory nuisance (against all defendants) under 17 M.R.S. § 2802,
7. Violations of Maine's Unfair Trade Practices Act (against all defendants) for allegedly making misrepresentations to the consumers regarding the defendants' products,
8. Strict liability for failure to warn (against the defendants other than API) for failing to warn about risks associated with the oil and gas companies' fossil fuel products.

The petition seeks compensatory damages for past and future harms, punitive damages, civil penalties under the Maine Unfair Trade Practices Act, attorney fees, and disgorgement of profits, as well as injunctive relief to prohibit the defendants from continuing to engage in various actions that the petition complains about. A copy of Maine's petition is available at: https://www.maine.gov/tools/whatsnew/attach.php?id=13129752&an=1.

Pennsylvania Enacts Carbon Capture and Sequestration Law

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On July 17, 2024, Pennsylvania Gov. Josh Shapiro signed the Carbon Capture and Sequestration Act (Act) into law. Act of July 17, 2024, P.L. 933, Act No. 87. The Act took immediate effect. This legislation adds Pennsylvania to a growing list of states enacting carbon capture and sequestration laws (currently North Dakota, Indiana, West Virginia, Alaska, Colorado, Illinois, Louisiana, and Wyoming). This article provides an overview of the key provisions of the Act. The Act creates an ownership interest in pore space and establishes collective storage similar to pooling in the oil and gas industry but does not alter, amend, diminish or invalidate rights to any preexisting use of pore space. It also grants rulemaking authority to the Environmental Quality Board, creates a Carbon Dioxide Storage Facility Fund, sets a reasonable standard of care for liability of storage operators, and vests ownership of stored carbon in the Commonwealth once a certificate of project completion is issued (50 years after carbon dioxide injections end).

Pore Space Ownership

Under the Act, the surface owner owns the pore space. The Act defines pore space as the "subsurface strata, formations, cavities or voids, whether natural or artificially created, that can be used as a storage space for carbon dioxide or other media." An owner can, however, sever the pore space as a separate property interest. *Id*. A public notice and comment period must precede any conveyance of pore space involving public land, as either a pore space conveyance or a lease. Public lands include, but are not limited to, land owned and managed by the Commonwealth of Pennsylvania, a municipality, an agency, or an authority. *Id*. at § 4(c). With respect to the use of subsurface rights, "the mineral, including coal, or oil and gas estate is dominant, including the surface use necessary for the subsurface development of the mineral, including coal, or oil and gas estate, regardless of whether ownership of the pore space is vested in the surface property interest owner or is owned separately from the surface." *Id*. at § (d)(2). The Act did not "alter, amend, diminish or invalidate rights" to any preexisting use of pore space. *Id*.

Whenever transferred, pore space shall be used only for the stated purpose of the transfer. *Id*. at § (e)(2). Like other interests in real property, any transfer or conveyance must be properly recorded. *Id*. Additionally, any transfer under the Act must specifically describe the "location of the pore space being transferred." *Id*. Such description "may include a metes and bounds description of

[1] The author appreciate the contributions of Kizito Aidam, Steptoe & Johnson associate.

the surface lying over the transferred pore space and identification of the subsurface strata, formations or reservoirs." *Id*. If, however, the transfer only describes the surface, the Act deems such a transfer to include the underlying pore space at all depths. *Id*.

Ownership of Injected Carbon

Ownership of carbon dioxide and "other substances injected incidental to the injection of carbon dioxide" belongs to the storage operator. *Id*. at § 7(a). This ownership comes with "all rights, benefits, burdens and liabilities." *Id*. Claimants must demonstrate an injury to sustain an action for damages against storage operators. Also, a claimant must show that the storage operator failed to act with "reasonable care." Any injured party, including the subsurface property owner and the surface property interest owner, can institute an action for damages. *Id*. at § 8(a). The available remedies include (i) general and special damages, (ii) punitive damages, (iii) attorney fees and costs, (iv) equitable reliefs, and (v) other "necessary and proper" reliefs. *Id*. at § 8(b). The Act limits punitive damages in instances where "the storage operator is determined to have had a reasonable basis for believing that the carbon sequestration project would not result in migration of carbon dioxide beyond the storage facility." *Id*. at § 8(b).

Collective Storage

The Act permits individuals, organizations, and other legal entities to initiate projects that involve underground storage of carbon dioxide. *Id*. at § 5. These individuals, organizations, and other legal entities form storage operators. Carbon sequestration projects must obtain at least one Underground Injection Control (UIC) Class VI permit. *Id*. at § 1. Ordinarily, storage operators that intend to carry out carbon sequestration projects must do so with the permission of the pore space owners. *Id*. at § 5(a).

In instances where storage operators are unable to obtain the consent of all pore space owners in the operations area, the Act empowers the Environmental Hearing Board to order the inclusion of pore space owned by nonconsenting owners. *Id*. The Environmental Hearing Board may only enter an order if the prospective storage operator made a "good-faith negotiation" to obtain the consent of all the pore space owners. *Id*. at § 5(a)(2). Furthermore, the prospective storage operator must have obtained consent from at least 75% of the pore space owners within the "subsurface area consisting of the extent of a carbon dioxide plume which is required to be delineated on an approved UIC Class VI permit or an amendment to a UIC Class VI permit of a storage operator." *Id*. Storage operators must submit a list of "reasonably known" pore space owners to the Environmental Hearing Board.

Before entering a collective storage order, the Environmental Hearing Board must provide notice to all the pore space owners. *Id*. at § 5(b)(1).

Prior to the forced collective storage order, the law requires storage operators to publish a notice at least 30 days before the application for collective storage order "in the newspaper of the largest circulation in each county in which the pore space is located." *Id*. at § 5(b)(3). This notice must include (i) a statement about the application for a collective storage order; (ii) a description of the proposed pore space; (iii) the name of the last known pore space owner, where the current owner is unknown; (iv) the address of the last known pore space owner, where the current owner is unable to be located; and (v) a statement that anyone claiming an interest in the proposed collective pore storage must "notify the Environmental Hearing Board and the storage operator at the published address within 20 days of the publication date." *Id*.

When entered, a collective storage order does not grant any surface use or access to the storage operator. Furthermore, the Act places certain limits on the Environmental Hearing Board's authority to issue collective storage orders. First, the Environmental Hearing Board ("EHB") may not enter collective storage orders concerning operations on public lands. *Id*. at § 5(d). Second, the EHB may not enter collective storage orders with respect to lands subject to the Conservation and Preservation Easements Act. *Id*. Third, the EHB may not enter collective orders regarding lands owned or managed by charitable entities, or to those lands owned or managed for a variety of environmental, agricultural, and historical purposes. *Id*. Fourth, the limitation applies to lands acquired under P.L. 992, No. 442 of 1968, an "act authorizing the Commonwealth of Pennsylvania and local government units thereof to preserve, acquire or hold land for open space uses." *Id*.

Seismic Exploration

Under the Act, storage operators must prepare "a seismic activity review" pursuant to a UIC Class VI permit. *Id*. at § 5.1. Operators must conduct "a seismic survey or assessment across the vicinity of a potential storage facility" before seeking a UIC Class VIA permit. *Id*. The Act limits the scope of seismic surveys to geologic storage. Such surveys shall "remain confidential and proprietary." If an operator is unsuccessful in obtaining the permission of a surface owner for the right to conduct a seismic survey, the PA Secretary of Environmental Protection may issue an order, subject to the payment of "just and reasonable compensation" to the surface owner, permitting the storage operator to enter said lands. *Id*. at § 5.1(d). The compensation shall be determined by the secretary. *Id*.

Additionally, the "storage operator shall defend, indemnify and hold harmless the property owner for all claims arising out of entry onto the property by the storage operator, its contractors and its agents." *Id*. at § 5.1(e). A storage operator shall also "deploy and maintain a seismicity monitoring system to determine the presence or absence, magnitude and the hypocenter location to the best of the storage operator's ability of seismic activity within the vicinity of the storage facility of a Richter scale magnitude as may be necessary to perform a risk analysis for unacceptable induced seismicity levels." *Id*. at § 5.1(c). The Pennsylvania Department of Environmental Protection ("DEP") may allow storage operators to discontinue seismicity monitoring if, based on "carbon sequestration project-specific risk analysis," the secretary determines that there is no need for permanent seismic monitoring for a specific project. *Id*.

The Environmental Quality Board and Its Rulemaking Authority

The Act grants rulemaking authority to the Environmental Quality Board. *Id*. at § 6(b). It also permits the board to set the necessary criteria for carbon sequestration. *Id*. Protection of natural resources as well as public health, safety, and welfare are paramount. *Id*. For a carbon sequestration project, the Act requires storage operators to protect current and prospective natural resources by isolating such resources. *Id*. Whenever "commercially valuable" natural resources are present, an operator shall design carbon sequestration projects to isolate the resources to the board's satisfaction. *Id*. The Act does not define "commercially valuable minerals." *See id*. In addition to obtaining the board's permission, a storage operator must notify subsurface property interest owners, and if an owner raises an objection, the storage operator must satisfactorily address the objection. *Id*.

Other responsibilities of the board include setting a fee to be paid by each storage operator for every ton of carbon dioxide injected for storage. *Id*. at § 9(c). Regarding the fees, 50% shall be deposited into a fund created under the Act, and the remaining 50% shall be deposited into a restricted account within the same fund. *Id*. This fund (the Carbon Dioxide Storage Facility Fund) and the restricted account are placed in the state treasury. *Id*. at § 10. The DEP shall use the fund for processing of permits, regulating storage facilities, and making storage determinations whereas the restricted account is intended to be used for "costs associated with long-term monitoring and management of a closed storage facility." *Id*.

Certificate of Project Completion and Vesting in the Commonwealth

The Act mandates the DEP to issue a certificate of project completion when a storage operator petitions that it has completed underground carbon storage. *Id*. at § 11(a). The certificate will be issued after the DEP issues a public notice, including an opportunity for public hearing. *Id*. The Act also sets a time frame on the issuance.

A certificate “shall not be issued until at least 50 years after carbon dioxide injections end or until an approved alternative period of time.” *Id*. at § 11(b).

Additional conditions include, but are not limited to, compliance with all laws, resolution of pending claims regarding underground carbon storage, and no expectation of vertical or horizontal expansion of the carbon dioxide that would pose public health and environmental threats. *Id*. at § 11(c). Other conditions include completion of all mandated reclamations and confirmation that wells, equipment, and facilities “are in good condition and will retain mechanical integrity.” *Id*.

After the issuance of the certificate of project completion, “title to the stored or injected carbon dioxide, and any facilities used to inject or store the carbon dioxide, without payment of compensation, shall be transferred to the Commonwealth.” *Id*. at § 11(d). Vesting in the commonwealth is in “exchange for assuming responsibility and liability for the stored carbon dioxide.” *Id*. The Commonwealth’s scope of liability is not limitless though. Primary responsibility and liability do not transfer to the Commonwealth in criminal and contractual situations. *Id*. at § 11(d)(3). Similarly, the Commonwealth does not bear responsibility and liability in situations where (i) the storage operator violated a duty or regulation; (ii) the DEP determines that the operator provided “deficient or erroneous information that was material and relied upon by the DEP to support approval of site closure”; (iii) the DEP determines that carbon dioxide migration, attributable to the operator, “causes or threatens imminent and substantial endangerment to an underground source of drinking water”; or (iv) there is an insufficient balance in the escrow or the fund to cover attendant costs. *Id*.

The Act expects the federal government to assume responsibility for the long-term monitoring and management of carbon dioxide. Until then, the DEP shall be responsible for monitoring and management. *Id*. at § 11(d)(6).

Texas Appellate Court Interprets Meaning of “Free of Costs Forever” in NPRI Reservation

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In *Fasken Oil and Ranch, Ltd. v. Puig*, 2024 WL 4608591 (Tex App.—San Antonio 2024), the parties disputed whether a nonparticipating royalty interest (NPRI) that was “free of costs forever” was free of both production and post-production costs, or just free of production costs. The court determined that it was free of both production and post-production costs.

Facts

In 1960, P.A. Puig, Jr. and Emilia Guitierrez Puig sold their ranch, reserving a one-sixteenth NPRI in favor of B.A. Puig, Jr. that was to be “free of costs forever.” The plaintiffs in this case were successors-in-interest to this NPRI. The defendant was Fasken Oil, which held the oil and gas leasehold interests covering areas that had been part of the ranch sold in 1960.

Fasken Oil operates oil and gas wells on the property and pays the plaintiffs royalties on that production. Historically, Fasken deducted post-production costs in calculating the royalties. In 2021, the plaintiffs filed suit in state court in Webb County, Texas, contending that Fasken was not entitled to deduct post-production costs. The plaintiffs sought damages for the underpayment of royalties and a declaratory judgment that their NPRI was free of both production and post-production costs. Fasken sought a declaratory judgment that the royalty is subject to deduction of post-production costs.

The plaintiffs filed a motion for partial summary judgment on their claim for a declaratory judgment, and Fasken filed a motion for partial summary judgment on its claim for a declaratory judgment. The district court denied Fasken’s motion and issued a judgment that granted the plaintiffs’ motion for a declaratory judgment that the NPRI is free of both production and post-production costs. The district court then authorized a permissive appeal on the issue of whether the NPRI is subject to a deduction of post-production costs. The appellate court allowed the appeal.

The appellate court noted that royalties typically are free of production costs (such as drilling costs and the costs of operating a well), but are subject to a deduction of post-production costs incurred prior to sale of the product (such as gas processing to remove impurities, as well as compression and transportation costs to move the natural gas to a buyer). However, parties may draft a royalty clause to vary from this general rule.

The appellate court compared the "free of costs" language in the reservation at issue to the language at issue in *Chesapeake Exploration, L.L.C. v. Hyder*, 483 S.W.3d 870 (Tex. 2016). In *Hyder*, the royalty clause provided for a "perpetual, cost-free (except for its portion of production taxes) overriding royalty of five percent (5.0%) of gross production." The appellate court reasoned that the Puig royalty's "free of cost forever" language was similar to the *Hyder* royalty's "perpetual, cost-free" language.

Fasken attempted to distinguish *Hyder* by arguing that *Hyder* relied on the fact that the royalty clause in that case provided that it was free of costs, except for "production taxes." Because production taxes are considered a post-production cost, the *Hyder* clause effectively stated that the royalty was free of costs, except for a particular type of post-production costs. *Hyder* noted that the provision at issue in the case made an express exception to the cost-free basis of the royalty, by allowing deduction of a cost classified as a post-production cost. This cut against the operator's argument that the royalty is subject to other post-production costs. After all, why would the royalty clause expressly state that the royalty was subject to deduction of a particular post-production cost if the royalty already was subject to a deduction of *all* post-production costs. Fasken noted that the royalty clause at issue in its leases did not contain a similar provision that expressly allowed the deduction of certain post-production costs.

But the appellate court in *Fasken* rejected this basis for distinguishing *Hyder*. As read by the appellate court in *Fasken*, the language in the *Hyder* lease that expressly allowed the deduction of particular post-production costs was not essential to the Texas Supreme Court's holding in that case. Instead, that language is merely additional support for a conclusion that the Texas Supreme Court already had reached—namely, that the natural meaning of "costs" includes both production costs and post-production costs. Thus, a royalty that was free of "costs," was free of both production and post-production costs.

Fasken also argued that the cost-free language was mere surplusage, referring only to the production costs from which royalties are always (or almost always) free. The appellate court disagreed. It acknowledged that this argument could have force if, as in *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996), the royalty clause provided for valuation at the well. *Heritage* noted that, in such a case, cost-free language is mere surplusage that refers to the post-production costs from which a royalty is always free. This is because the so-called "deduction" of post-production costs in such a case is not a means of making the royalty owner share in post-production costs. Instead, the deduction of post-production costs form the sales price is simply a means of estimating the *value at the well* when the royalty clause provided for a royalty to be based on the value at the well, but the sale of product took place at a distant location, not at the well, so that the sales price does not represent the market value at the well.

Here, the Puig reservation of an NPRI did not provide for a valuation point. Fasken argued that the NPRI clause's reference to "production" set the valuation point at the well, but the court disagreed. Therefore, the appellate court affirmed the district court's judgment that the plaintiffs' NPRI was free of both production costs and post-production costs.

West Viriginia Extends Marketable Title Rule, Adopting Point-of-Sale Rule

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In *Romeo v. Antero Resources Corp.*, 2024 WL 4784706 (W. Va. 2024), 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 to the West Virginia Supreme Court of Appeals, which accepted the certified questions in an order issued in May 2024. The questions concern the calculation of the royalty owed on the sale of natural gas liquids (NGLs).

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.

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.

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

By a 3-to-2 vote, the Supreme Court's majority rejected the lessee's arguments. 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 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).

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 dissent vigorously disagreed. The dissent 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. The dissent also disagreed that the majority's conclusion that the majority's "point of sale" rule naturally follows from the Court's existing marketable product rule jurisprudence. The dissent characterized the point-of-sale rule as a significant extension—and a bad one at that—of the marketable product rule. The 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?

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