Without a *Leggett* to Stand On: Arguing for Retroactive Application of West Virginia's Amended Flat-Rate Well Statute

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Wilson: Without a <em>Leggett</em> to Stand On: Arguing for Retroactive Application of West Virginia’s Amended Flat-Rate Well Statute

Student Note by Adam H. Wilson

**WITHOUT A LEGGETT TO STAND ON:**
ARGUING FOR RETROACTIVE APPLICATION OF WEST VIRGINIA’S AMENDED FLAT-RATE WELL STATUTE

What both the foregoing and the majority’s opinion underscores is the necessity of the Legislature to address these policy-laden issues and declare, by statute, the will of the State’s citizenry in this regard. This Court is constrained to our canons of statutory construction and does not make policy. . . . Where the Legislature’s inaction in the face of such significant changes in the industry leaves this Court to intuit its intentions and/or retrofit outdated statutory language to evolving factual scenarios, the will of the people is improperly disregarded.

—Justice Margaret Workman

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I. INTRODUCTION

Arnold and Mary Richards married in 1951 and, in 1954, bought a 264-acre farm in Harrisville, West Virginia.\(^2\) Arnold worked as a millwright in nearby Parkersburg for over 40 years, while Mary tended to the home and farm.\(^3\) The couple initially owned half of the mineral rights beneath their land, and they bought the remaining half over the years.\(^4\) The previous owner had drilled several natural gas wells on the property, and the Richardses received modest royalty payments from these wells.\(^5\)

In 2014, EQT Corporation, America’s largest natural gas producer,\(^6\) acquired the right to drill on the Richards’s farm.\(^7\) EQT drilled six natural gas wells into the couple’s minerals,\(^8\) using hydraulic fracturing\(^9\) to produce the gas trapped below.\(^10\) When the first check arrived, the Richards’s royalty


\(^3\) Id.

\(^4\) Id.

\(^5\) Id.


\(^7\) Ward Jr., supra note 2.


\(^9\) Hydraulic fracturing is the process of drilling a natural gas well by injecting water, sand, and chemicals under high pressure into the oil or gas bearing rock formation; this stimulation increases fluid flow and, consequently, production. What is Hydraulic Fracturing?, U.S. GEOLOGICAL SURV., https://www.usgs.gov/faqs/what-hydraulic-fracturing?qt-news_science_products=0#qt-news_science_products (last visited Sept. 17, 2021).

\(^10\) Ward Jr., supra note 2.
skyrocketed, just as they expected. However, they were also shocked to learn that EQT had withheld thousands of dollars of their royalty payment, charging the couple for state severance taxes and operating expenses. Arnold contacted EQT, wanting to know why the company charged him for these expenses; EQT told Arnold that he would be paying part of these costs.

The Richardses were unsatisfied with this answer and sued EQT for diluting their royalty payments. EQT defended on the grounds that the couple should be responsible for part of the taxes and expenses. Following a three-day jury trial, the Richardses prevailed. The jury found that EQT had improperly charged Arnold and Mary for expenses that mineral owners have no obligation to pay. In all, EQT was forced to repay every penny withheld—a total of $235,381.13—and was prohibited from charging the couple in the future.

The Richards’s story is, unfortunately, all too common among West Virginia mineral owners. Natural gas companies promise to make each mineral owner a millionaire within a matter of years and, in turn, receive permission to drill for natural gas on their land. The company then drills several wells, producing tens of millions of cubic feet of gas, only to minimize the royalty payments by charging the mineral owner for “post-production” expenses. These expenses—the costs of gathering, processing, and transporting natural gas—are deducted from the royalty payments and have become a point of contention between gas companies and mineral owners.

Royalty disputes are a recurring problem in West Virginia that are likely to increase as the state’s natural gas industry continues to grow. In 2007, a Roane County jury returned a $404 million verdict against Columbia Natural Resources after it charged mineral owners for post-production expenses without...
their knowledge.\textsuperscript{23} Twelve years later, EQT paid $53.5 million in a class action settlement after diluting the royalties of approximately 9,000 mineral owners.\textsuperscript{24} Today, West Virginia’s largest natural gas companies, such as Antero Resources, EQT, and Jay-Be Oil & Gas,\textsuperscript{25} face continuing litigation by mineral owners seeking to recover unpaid royalties.\textsuperscript{26}

Courts currently disagree whether certain royalties are chargeable with post-production expenses.\textsuperscript{27} In 1982, the West Virginia Legislature enacted West Virginia Code section 22-6-8, commonly known as the “flat-rate” statute, intending to ensure mineral owners receive their fair share of natural gas royalties.\textsuperscript{28} The statute’s original language required royalties be based on the proceeds at the first point of sale, which occurred immediately after the gas exited the ground.\textsuperscript{29} Unfortunately, changing industry regulations, coupled with creative accounting by natural gas companies, resulted in these companies using the outdated statutory language to manipulate and dilute royalties paid to mineral owners.\textsuperscript{30}

In \textit{Legget v. EQT Production Co.}, the West Virginia Supreme Court attempted to address whether royalties paid according to section 22-6-8 are


\textsuperscript{27} Compare Memorandum Opinion and Order Regarding Defendant’s Motions in Limine, Fout v. EQT Prod. Co., No. 1:15-CV-68, 2018 WL 1725608, at *7 (N.D. W. Va. Apr. 6, 2018) (ruled that deductions taken from flat-rate royalties prior to enactment of Senate Bill 360 are permissible), with Order Granting Plaintiffs’ Motion to Have W. Va. Code § 22-6-8(e), as Amended By Senate Bill 360, Determined as Controlling in this Case, Huey v. EQT Prod. Co., No. 17-C-43, at 17–18 (Cir. Ct. Wetzel Cnty. Sept. 9, 2020) (ruled that deductions taken prior to Senate Bill 360’s enactment are prohibited), and Order Granting Plaintiffs’ Motion to Have W. Va. Code § 22-6-8(e), as Amended By Senate Bill 360, Determined as Controlling in this Case, Secrist v. EQT Prod. Co., No. 14-C-19, at 19–20 (Cir. Ct. Doddridge Cnty. May 22, 2019) (same).

\textsuperscript{28} Ward Jr., supra note 2.

\textsuperscript{29} W. VA. CODE ANN. § 22-4-1 (West 1982) (requiring natural gas royalties be calculated “at the wellhead”) (later re-codified as W. VA. CODE ANN. § 22-6-8 (West 1994)).

\textsuperscript{30} Ward Jr., supra note 2.
subject to deductions for post-production expenses but reached conflicting outcomes.\(^{31}\) The Court initially ruled, in Leggett I, that mineral owners receiving royalties under the flat-rate statute cannot be charged for post-production expenses.\(^{32}\) The Court reheard the case, however, and reversed itself in Leggett II, holding that post-production expenses may be deducted from royalties paid according to section 22-6-8.\(^{33}\) In Leggett II, the Court invited the Legislature to resolve the conflict by amending the flat-rate statute, thereby clarifying whether mineral owners may be charged for post-production expenses.\(^{34}\) The Legislature responded to these invitations in 2018 by passing Senate Bill 360, which amended the flat-rate statute and expressly stated that royalties cannot be diluted with post-production expenses, effectively codifying Leggett I’s holding.\(^{35}\)

This Note argues that Senate Bill 360 clarified, as opposed to altering, section 22-6-8 and the amended statute therefore applies retroactively, effectively overruling Leggett II. Part II provides the necessary background information to understand flat-rate leases and royalty calculations,\(^{36}\) while Part III explains the flat-rate statute’s purpose and effect on flat-rate royalties.\(^{37}\) Next, Part IV explores the impact of natural gas pipeline deregulation on natural gas sales;\(^{38}\) Part V discusses West Virginia’s common law jurisprudence regarding royalty disputes;\(^{39}\) Part VI then analyzes Leggett I and Leggett II before examining the legislative history of Senate Bill 360.\(^{40}\) Finally, Part VII argues that Senate Bill 360 clarified section 22-6-8’s prohibition of post-production expenses and therefore applies retroactively.\(^{41}\)


\(^{33}\) Leggett II, 800 S.E.2d at 867.

\(^{34}\) Id. at 869; id. at 871 (Workman, J., concurring).


\(^{36}\) See infra Part II.

\(^{37}\) See infra Part III.

\(^{38}\) See infra Part IV.

\(^{39}\) See infra Part V.

\(^{40}\) See infra Part VI.

\(^{41}\) See infra Part VII.
II. A CRASH COURSE IN OIL AND GAS

This Note focuses on natural gas leases, post-production expenses, and royalty calculations. Because these topics are quite complex, some background information is needed before examining each in detail. Section A explains the different types of leases used in the natural gas industry, and Section B explores what post-production expenses natural gas companies charge mineral owners. Finally, Section C examines natural gas companies’ preferred method of calculating royalties: the net-back method.

A. Mineral Lease Basics

Before a gas well is drilled, a contract must be executed between the mineral owner and gas company. This agreement is referred to as the mineral lease; the mineral owner is the lessor, while the gas company is the lessee. Each lease contains express promises and implied covenants that both parties bind themselves to for the mutual benefit of one another. The royalty clause is perhaps the most important lease provision. A “royalty” is the mineral owner’s compensation for the natural gas once it has been produced and sold. Today, natural gas is sold per thousand cubic feet (MCF), and royalties are based on the volume of gas sold, often one-eighth (12.5%) of the sale proceeds. Leases that pay a volume-based royalty are known as “freely negotiated” leases because the royalty is a product of free negotiations between the lessor and lessee.

However, natural gas royalties have not always been related to the volume of gas sold. During the oil and gas industry’s infancy, wells were drilled with the aim of producing oil, and it was considered a waste when a well only produced natural gas. This is because, during the late 1800s and early 1900s,
there was no infrastructure—natural gas pipelines—to gather and transport the gas to a buyer.\textsuperscript{53} Without pipelines in place, there was no market for the product.\textsuperscript{54} Frequently, after the gas well was drilled, the lessor was allowed to access the gas and use it for his own residential purposes.\textsuperscript{55} Other times, the well was abandoned altogether.\textsuperscript{56} Until the 1920s, standard leases reflected these limitations and included a “flat-rate” royalty clause.\textsuperscript{57} A flat-rate royalty is just that: a fixed payment to the lessor, not for the volume of gas sold, but instead for the right to have a well located on the leased premises.\textsuperscript{58} Flat-rate leases commonly referred to this as a “gas rental” and paid an annual sum that varied from $50 to a few hundred dollars per well.\textsuperscript{59} 

Mineral leases, oil and gas leases specifically, have a unique feature that allows the lease to continue indefinitely. Each lease contains a “primary term” that specifies the timeframe during which drilling operations have to begin.\textsuperscript{60} If a producing well is not drilled before the primary term’s end, the lease terminates and both parties are freed from all obligations under the lease.\textsuperscript{61} Leases also include a “secondary term” that becomes effective once production begins.\textsuperscript{62} The secondary term typically includes language that allows the lease to continue for “so long as [oil or gas is] produc[ed] in paying quantities.”\textsuperscript{63} The secondary term’s effect is significant: the lease remains active for so long as the operator reports production in paying quantities and allows the minerals to be “held by production.”\textsuperscript{64} In addition, the lease’s terms apply to each additional well drilled on the property and also prevent the lease from terminating.\textsuperscript{65} Consequently,
many flat-rate leases executed at the turn of the twentieth century remain active to this very day, so long as there has not been a sufficient lapse in production to terminate the lease.66

B. From the Wellhead to Buyer: Post-Production Expenses

Post-production expenses are a contentious—and at times litigious—matter between mineral owners and natural gas companies.67 These are not merely the costs of compressing and transporting natural gas but each expense incurred between the wellhead and eventual third-party buyer. This Section describes each post-production expense and details the process of gathering, treating, and transporting natural gas.

Natural gas is trapped in deposits, commonly known as reservoirs,68 located thousands of feet below the earth’s surface.69 Raw natural gas consists of numerous hydrocarbons, including methane, ethane, propane, butane, and occasionally pentane.70 Methane, the lightest component part,71 is separated, marketed, and sold individually for consumer and industrial use through the interstate pipeline.72

Isolating methane from the remaining constituent parts is no trivial matter; the gas must pass through an intricate series of pipelines and equipment before becoming a marketable product. Natural gas first passes through the “wellhead” after exiting the ground; this is the permanent steel fitting that sits atop the well.73 Almost immediately after leaving the wellhead, the gas travels through the “separator,” which removes all liquids from the gas stream.74

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70 Selley & Sonnenberg, supra note 68, at 14–15.
74 Id. at 375.

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gas stream then travels a short distance to a nearby meter that measures the volume of gas produced.\textsuperscript{75}

Next, it flows through a series of pipelines called “gathering lines” that gather and collect gas from nearby wells before merging at a central gathering location.\textsuperscript{76} Once there, a transmission pipeline consolidates the gas from several gathering lines.\textsuperscript{77} The gas is compressed during this transition to increase its pressure, making it easier to transport larger volumes of gas.\textsuperscript{78} After entering the transmission pipeline, the gas travels to a processing facility where it is further divided into its component parts\textsuperscript{79} using a process known as “fractionation.”\textsuperscript{80}

Once isolated, and therefore marketable, the methane enters the interstate pipeline\textsuperscript{81} where an unaffiliated third-party buyer purchases the gas in an arm’s length transaction.\textsuperscript{82} Natural gas companies paying royalties via the net-back method must account for each expense incurred between the wellhead and buyer, which is then charged to the mineral owner.\textsuperscript{83}

\textbf{C. The Net-Back Method in Theory}

Natural gas royalties have historically been based on the gross proceeds from the gas sold at the wellhead.\textsuperscript{84} This is no longer the practice because, as discussed \textit{infra},\textsuperscript{85} changes in regulatory policy have moved the first point of sale

\begin{footnotesize}
\begin{enumerate}
\item \textit{Id.} at 386.
\item WILLIAMS & MEYERS, supra note 64, at 441–42.
\item WILLIAMS & MEYERS, supra note 64, at 413 (“Fractionation is the process whereby mixed natural gas or ‘raw make’ is separated into its component parts.”).
\item See generally Byron C. Keeling, \textit{In the New Era of Oil and Gas Royalty Accounting: Drafting a Royalty Clause That Actually Says What the Parties Intend It to Mean}, 69 BAYLOR L. REV. S16, 524–25 (2017) (discussing how different courts allow lessees to calculate royalties when intra-company sales are made).
\item Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1154 (Pa. 2010).
\item DONLEY, supra note 55, § 104, Keeling, supra note 82, at 517.
\item See \textit{infra} Part IV.
\end{enumerate}
\end{footnotesize}
further “downstream,”86 away from the wellhead. As a result, there is no longer a market for natural gas at the wellhead.87 Leases executed prior to this shift, however, specified that royalties must be based on the value at the wellhead.88 Currently, the downstream value of natural gas is higher than that at the wellhead; this price difference is a direct result of the costs of gathering, treating, and transporting the gas to the market.89

Lessees that attempt to stay true to history and, coincidentally, pay a smaller royalty, have developed a system to recreate the lower wellhead price. Known as the “net-back” method, this process attempts to estimate the value of natural gas if it were sold at the wellhead.90 Lessees argue that the only accurate way to determine the price difference between the true market value91 and artificial wellhead price is to deduct each post-production expense from the amount received.92

The net-back method requires the lessee account for, allocate, and deduct expenses from the gross proceeds before paying the lessor’s royalty. The lessee first takes the gross price received at the interstate pipeline—the first point of sale—and deducts numerous expenses.93 These expenses typically include, but are not limited to,94 the costs of gathering, processing, and transporting the gas.95

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86 “Downstream” refers to operations performed after a specified reference point. WILLIAMS & MEYERS, supra note 64, at 285. This Note uses the natural gas well itself as the reference point, and all operations occurring beyond the well are considered downstream.

87 Leggett II, 800 S.E.2d 850, 857 (W. Va. 2017) (“As a result [of deregulation], oil and gas are no longer sold ‘at the wellhead,’ but rather are sold downstream of the wellhead, typically at the interstate pipeline.”).

88 Keeling, supra note 82 (“Until fairly recently, the vast majority of royalty clauses required that the lessee calculate its royalty payments ‘at the well’ or ‘at the wellhead.’”).

89 Leggett II, 800 S.E.2d at 857 (“[O]ne of the effects of [post-production operations] . . . is that the sales price is enhanced from the wellhead price because it is now a marketable, useable product when it is first sold at market . . . .”).

90 Kilmer v. Eleco Land Servs., Inc., 990 A.2d 1147, 1149 (Pa. 2010) (“This calculation is called the ‘net-back method,’ as its goal is to determine the value of the gas when it leaves the [wellhead] . . . .”).

91 The “market value” of natural gas is the price that a willing buyer would pay to a willing seller in a free market. 3 KUNTZ, supra note 51, § 40.4.

92 Leggett II, 800 S.E.2d at 853–54 (“EQT maintains that the only way to capture the statutorily-required ‘wellhead’ price is to utilize this so-called ‘net-back’ or ‘work-back’ method which deducts postproduction expenses from the sales price to duplicate the ‘wellhead’ price.”).

93 Young v. Equinor USA Onshore Props., Inc., 982 F.3d 201, 203–04 (4th Cir. 2020).

94 See infra Section VII.B.

95 WILLIAMS & MEYERS, supra note 64, at 800.

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The lessee then charges the lessor his pro rata share of each expenditure. After each expense has been accounted for, apportioned to the lessor, and deducted, the lessee can estimate the wellhead price. This artificial, net price is used to calculate the lessor’s royalty instead of the gross price received by the lessee.

A hypothetical is helpful to illustrate the net-back method’s financial impact on mineral owners. For example, suppose Joe inherited a 50-acre mineral estate from his grandfather in Ritchie County, West Virginia. Prior to his death, Joe’s grandfather leased the minerals to Robin Gas Company (“Robin Gas”). The lease provides for a standard one-eighth royalty, meaning Joe will receive 12.5% of the proceeds from the gas sold from his minerals.

Robin Gas recently drilled a single natural gas well on the property that produces approximately 500,000,000 cubic feet of gas (500,000 MCF) each month. The market price of gas is $2.50/MCF, and Robin Gas receives $1,250,000 in gross proceeds each month. Before paying Joe’s royalty, Robin Gas must use the net-back method to recreate the wellhead value of gas. Robin Gas is notorious for charging mineral owner’s for excessive expenses, and Joe is no exception. Unsurprisingly, his royalty is reduced by 40% once Robin Gas calculates the wellhead value as $1.50/MCF. If Robin Gas used the true market price, Joe would receive $15,625 for his share of the natural gas. Unfortunately, his royalty is based on the artificial wellhead value and his check reflects that fact. Joe’s monthly royalty is $9,375, over $6,000 less than it would be if Robin Gas paid the royalty based on the gross proceeds instead of the net proceeds.

III. ORIGINAL ENACTMENT OF THE FLAT-RATE STATUTE

As the natural gas industry evolved, several innovations revolutionized business practices and were unforeseen by the parties to flat-rate leases. First, drilling technology improved dramatically during the industry’s first 100 years. Gas companies were able to drill further into the earth, producing gas.

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96 The lessor’s pro rata share is the product of her royalty interest (usually one-eighth), net mineral acres owned, and the percentage of her minerals included in the entire pool. How Do I Calculate My Royalty Interest Within a Pooled Unit?, GATEWAY ROYALTY (July 29, 2019), https://gatewayroyaltyllc.com/how-do-i-calculate-my-royalty-interest-within-a-pooled-unit/.

97 See, e.g., Young, 982 F.3d at 205 (detailing the calculations used to charge lessors for post-production expenses).


99 Id.

that was previously believed unreachable. Additionally, gas recovery techniques improved substantially; drillers were able to extract more gas from the reservoir than in decades prior. Second, the introduction of high-pressure pipelines created a market for natural gas. Gas companies could, for the first time, transport the gas to a buyer rather than wasting it. Neither party to flat-rate leases contemplated these developments at the time of signing the lease. Otherwise, the royalty would be based on a portion of the sales proceeds, as opposed to a fixed, rental rate.

Flat-rate lessors suffered the consequences of these unforeseen developments. Prior to the 1930s—when flat rate leases were used—the lessor received adequate compensation for his minerals. For example, in 1925, a lessor receiving a $300 royalty could purchase a Ford Model T with money to spare. Unfortunately, this quickly changed because flat-rate leases did not account for inflation, nor did they allow the lessor to receive a share of the gas sale proceeds once a market developed. To add insult to injury, because the minerals could be held by production, lessors continued to receive the same fixed amount for decades, despite new wells being drilled with these modern techniques. The inequity soon became apparent when lessees were selling the gas and keeping the entire proceeds, except the nominal royalty payment due to the lessor.

In 1982, the West Virginia Legislature convened, intending to eradicate this unfair practice. The Legislature enacted the “flat-rate” statute, originally codified at West Virginia Code section 22-4-1 (later re-codified as section 22-6-
and forever changed how flat-rate lessors would be compensated for their valuable minerals. The Legislature meticulously detailed its basis for enacting the statute; the findings and declarations clause expressly stated the legislative intent to prohibit lessees from exploiting flat-rate lessors. First, a significant amount of natural gas was subject to development under flat-rate leases that paid the mineral owner based solely on the existence of a producing well instead of the volume of gas produced. Second, flat-rate leases provided mineral owners with “wholly inadequate” compensation that was unfair, oppressive, and worked an unjust hardship on mineral owners. Finally, flat-rate leases were decades old and had been entered into at a time when neither the modern technology, nor the depths natural gas was produced from, were known or contemplated by the parties.

Based on these findings, the Legislature declared that it was West Virginia’s policy to prevent natural gas production under flat-rate leases. Consequently, the Legislature found that the State had an obligation to prohibit issuing a drilling permit for future wells that would pay a flat-rate royalty. A lessee could, however, escape this permit prohibition by agreeing to pay the lessor a one-eighth royalty. The lessee could do so by submitting, in his permit application, an affidavit swearing the lessor would be paid “not less than one eighth of the total amount paid to or received by [the lessee] at the wellhead” in exchange for the gas produced and sold.

Contrary to critics of the flat-rate statute, the Legislature did not impair existing contractual obligations. Rather than amending or nullifying flat-rate leases, the statute prohibited the West Virginia Department of Environmental Protection from issuing new permits to drill a well under a flat-

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112 The flat-rate statute was originally codified at West Virginia Code section 22-4-1 (1982); the Legislature later re-codified the statute at West Virginia Code section 22B-1-8 (1985) before it was ultimately re-codified at West Virginia Code section 22-6-8 (1994).

113 W. VA. CODE ANN. § 22-4-1(a)(2) (West 1982).

114 Id. § 22-4-1(a)(1).

115 Id. § 22-4-1(a)(2).

116 Id. § 22-4-1(a)(3).

117 Id. § 22-4-1(b).

118 Id.

119 Id. § 22-4-1(e).

120 Id.


122 Section 10, Article I, Clause 10 of the United States Constitution and Section 4, Article III of the Constitution of West Virginia each prohibit the Legislature from impairing contractual obligations. See U.S. CONST. art. I, § 10, cl. 1; W. VA. CONST. art. III, § 4.
rate lease. Following enactment, however, operators would be denied a permit if the lease did not include a royalty tied directly to production; a permit could be granted only if the operator submitted an affidavit, included in the permit application, that stated the mineral owner would receive not less than a one-eighth royalty. Therefore, the flat-rate statute did not impair existing contracts. Rather, its only effect was to ensure no future wells would be drilled unless the mineral owner received at least a one-eighth royalty.

IV. TURBULENT TIMES: NATURAL GAS PIPELINE DEREGULATION

Although the West Virginia Legislature took great care to ensure that flat-rate lessors receive adequate compensation for their minerals, one variable remained that it could not control: natural gas pipeline regulations. The Legislature specified that royalties paid according to section 22-6-8 must be valued “at the wellhead” because, in 1982, federal regulations required the first point of sale be at the wellhead. Changing industry regulations, however, dramatically changed the natural gas sales market, leaving the statutory language—“at the wellhead”—outdated.

During the 1920s, high-pressure, steel pipelines were constructed that could transport natural gas over long distances at relatively low costs. State public utility companies (“PUCs”) initially regulated these pipelines; however, conflicting regulations from each PUC proved too problematic for interstate pipeline companies to manage. As a result, Congress passed the Natural Gas Act of 1938 (“NGA”) and required the Federal Power Commission (“FPC”) to regulate interstate pipelines.

The NGA heavily regulated the natural gas industry and featured three significant constraints. First, under the NGA, all natural gas sales took place at the wellhead. Second, these wellhead sales were made between the producer

123 Section 22-6-6 states that, if all statutory requirements are met, the Director of the West Virginia Department of Environmental Protection will issue a drilling permit. See W. VA. CODE ANN. § 22-6-6 (West 1994).
124 See id. § 22-4-1(d) (stating that no permit shall be issued in the future to drill or rework an existing well unless the lessee pays a one-eighth royalty).
125 Id. § 22-4-1(e).
126 Id.
127 See Associated Gas Distrib. v. FERC, 824 F.2d 981, 993 (D.C. Cir. 1987).
129 Id. Interstate pipeline companies encountered conflicting regulatory orders and protectionist regulatory policies from various state PUCs. Id.
130 Id.
131 See Associated Gas Distrib., 824 F.2d at 993.
(the lessee) and pipeline company (the third-party buyer), in arm’s-length transactions. Third, the pipeline company—acting entirely independent from other market participants—had a monopoly and only transported the gas that it sold. This last feature, known as “bundled” services, was the hallmark of the NGA for 40 years.

During the mid-1970s, the NGA’s regulations caused major natural gas shortages, which prompted Congress to change course and deregulate the industry. Congress first passed the Natural Gas Policy Act of 1978 (“NGPA”). The NGPA allowed the Federal Energy Regulatory Commission (“FERC”) to authorize pipelines to offer “unbundled” services and transport gas sold by third-parties. FERC responded in 1985 by issuing Order Number 436, which enticed pipelines to give up their monopoly power and provide unbundled services. Order Number 436’s effect on the industry impressed Congress, who next enacted the Natural Gas Wellhead Decontrol Act of 1989 (“NGWDA”), which ratified FERC’s de facto industry deregulation. In 1992, FERC promulgated Order Number 636 and formally deregulated the natural gas sales market. Order Number 636 required interstate pipeline companies to offer unbundled services, effectively acting as common-carriers for natural gas. Today, natural gas companies market the gas themselves and pay pipeline companies to transport the product to the downstream market.

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132 Id.
135 Natural gas pipeline companies only offered bundled services from 1938 until 1978, when Congress began deregulating the industry. Id. at 717–18.
136 Id. at 716.
139 Pierce, Jr., supra note 128, at 55.
140 Id. at 84.
141 Id.
142 Fagan, supra note 134, at 726–27.
143 Joyce Colson, Upstream, Midstream, Downstream—The Valuation of Royalties on Federal Oil and Gas Leases, 70 U. COLO. L. REV. 563, 593 (1999).
V. THE TANNEY TEST: WEST VIRGINIA’S COMMON LAW COST ALLOCATION DOCTRINE

While the unbundling of natural gas pipeline services improved the natural gas sales market, it also raised new questions. Most notably, who should bear the costs of gathering, treating, and transporting natural gas to the first point of sale became a heavily litigated issue. Two doctrines of cost allocation ultimately emerged in oil and gas producing states. Several states adopted the “marketable product rule,” which requires the lessee to pay all costs until the gas is marketable or ready to be sold. Alternatively, other states embraced the “at the wellhead” rule, demanding the lessor pay his pro rata share of expenses between the wellhead and first point of sale. West Virginia, however, did not address the issue for nearly a decade. Finally, in 2001, the question arose in the seminal case of Wellman v. Energy Resources, Inc.

James and Grace Wellman were lessors in two oil and gas leases covering 200 and 23.5 acres, respectively, located in Logan County, West Virginia. Energy Resources, Inc. (“Energy Resources”), the lessee, had leased the minerals from the Wellmans’s predecessor-in-title; both leases were identical for all practical purposes. Each lease required the lessee pay the lessors a royalty of “one-eighth (1/8) of the proceeds from the sale of gas as such at the mouth of the well where gas . . . is found.”

144 Clough v. Williams Prod. RMT Co., 179 P.3d 32, 36 (Colo. App. 2007) (referring to natural gas pipeline deregulation as “the major catalyst for the current wave of royalty litigation.”).
146 Raynes, Jr. supra note 67, at 1205–06.
147 Sternberger v. Marathon Oil Co., 894 P.2d 652, 659 (Colo. 1994) (en banc) (“[The lessee] has the duty to produce a marketable product, and the lessee alone bears the expense in making the product marketable.”); Garman v. Conoco, Inc., 886 P.2d 652, 659 (Colo. 1994) (“[T]he implied covenant to market obligates the lessee to incur those post-production costs necessary to place gas in a condition acceptable for market.”); Wood v. TXO Prod. Co., 854 P.2d 880, 882 (Okla. 1992) (“[T]he lessee's duty to market . . . include[s] the cost of preparing the gas for market.”).
150 Id. at 257.
151 Id.
152 Id. at 257–58.
Energy Resources entered upon the 23.5-acre tract and, for
approximately five years, operated a single natural gas well. During this time,
Energy Resources sold the gas for $2.22 per MCF, but paid the Wellmans’s
royalty as though the gas sold for $0.87 per MCF. The Wellmans sued Energy
Resources for these unpaid royalties and alleged that they had been short-
changed because Energy Resources improperly charged them with expenses.

The Court began assessing the Wellmans’s claim by noting that the
mineral owner’s royalty has traditionally been paid based on the first point of
sale and is not chargeable with the costs of discovery and production. Recently, the Court noted, lessees have tried to escape this rule by labeling
certain operating expenses as “post-production expenses,” which are in turn
charged to the lessor.

The Court recognized that in West Virginia, the lessee impliedly
covenants to market the oil or gas produced under the lease; this duty to market
includes the responsibility of placing the gas in a marketable condition and
transporting it to the market. Moreover, the lessee has historically borne the
costs of complying with all lease covenants. Therefore, the Court found that
the lessee should bear the costs associated with marketing the gas. The Court
ultimately held that when an oil and gas lease provides for a royalty based on
sale proceeds, the lessee must bear all costs associated with exploring for,
producing, marketing, and transporting the gas to the first point of sale, unless
the lease provides otherwise. When the lease provides that the lessor shall bear
some portion of these expenses, the lessee is entitled to credit for these costs to
the extent they were actually incurred and reasonable.

153 Id. at 258.
154 Id.
155 Id.
156 Id. at 263 (quoting DONLEY, supra note 55, § 104).
157 Id. at 263–64 (citing Davis v. Hardman, 133 S.E.2d 77 (W. Va. 1963)).
158 Id. at 264. These expenses include the costs of placing the gas in a marketable condition and
transporting to the point of sale. Id.
159 Id. at 265.
160 Id.
161 Id. The Court found that, although the lease language could have indicated that the lessor
should bear some portion of the post-production expenses, Energy Resources provided no evidence
to prove these expenses were actually incurred or reasonable. Id. See infra note 163.
162 Wellman, 557 S.E.2d at 265.
163 Id. Before being entitled to these deductions, the lessee must prove, by evidence of the type
normally developed in legal proceedings requiring an accounting, that these costs were actually
incurred and reasonable. Id. The Court further elaborated on this “reasonableness” standard, stating
that “the law’s allowance of reasonable costs . . . is not an invitation to or sanction of creative
accounting.” These costs “must be objectively reasonable . . . [and] actually incurred in the
Five years later, the Court faced the question that Wellman left unanswered: what lease language is sufficient to charge the lessor with his pro rata share of post-production expenses? Plaintiffs/lessors in Estate of Tawney v. Columbia Natural Resources, L.L.C., brought a class action lawsuit against Columbia Natural Resources, L.L.C. ("Columbia") for improperly deducting post-production expenses from their natural gas royalties. The majority of leases indicated that royalties were to be calculated “at the wellhead,” although the gas was sold further downstream.

Columbia charged the lessors with the costs of processing and transporting the gas; these deductions were taken in equal amounts, regardless of how far the gas travelled. The lessors received royalty checks that purported to state the amount of gas produced, the price for which gas was sold, and the amount of their royalty. Columbia did not disclose that it was deducting post-production expenses from the lessors’ royalties.

The Court found the lease language ambiguous and therefore insufficient to escape Wellman’s holding that the lessor must receive a royalty based on the sale price. Although the language potentially indicated that the royalty should be calculated at the wellhead, it shed no light as to how or by what method a lessee may do so. Equally important, the leases were silent altogether on the allocation of post-production expenses.

In its holding, the Court set forth a three-prong test that must be met before lessees can deduct post-production expenses. Leases that intend to allocate post-production expenses between the lessor and lessee must: (1)
expressly provide that the lessor shall bear some portion of these costs; (2) identify with particularity the deductions to be taken; and (3) indicate the method of calculating the amount to be deducted. The Court further held that lease language stating the royalty will be calculated “at the wellhead” is ambiguous and, therefore, ineffective to permit the lessee to deduct post-production expenses.

VI. LITIGATION AND LEGISLATION: LEGGETT V. EQT PRODUCTION COMPANY

Following Tawney, the law was well-settled that the lessee in a freely negotiated lease could not deduct post-production expenses, unless the lease expressly stated otherwise. This decision, however, only involved freely negotiated leases. Flat-rate leases governed by section 22-6-8 were not discussed in either Wellman or Tawney, and the Court did not consider whether Tawney had any effect on section 22-6-8 for another decade.

A. Leggett I

Plaintiffs/lessors were owners of an undivided 75% interest in a 2,000-acre mineral estate in Doddridge County, West Virginia. The property was subject to a 1906 lease, which called for a $300 flat-rate royalty. EQT Production Company (“EQT”), the successor lessee, drilled several natural gas wells on the property, and section 22-6-8 required EQT to pay a one-eighth royalty on these wells. The lessors sued EQT and several related entities, alleging that the lessee had improperly deducted post-production expenses from their royalties. EQT did this, the lessors claimed, primarily by establishing subsidiaries that charge the lessors for otherwise impermissible expenses.

174 Id. at 30.
175 Id.
176 Ward Jr., supra note 2.
177 Id.
178 Id.
181 Id. at *4.
182 These related entities included the parent company, EQT Corporation, and several sister-entities, including: EQT Energy, L.L.C., EQT Investments Holdings, L.L.C., EQT Gathering, L.L.C., and EQT Midstream Partners, L.P. Id. at *3 n.1.
183 Id. at *3.
184 Id. at *8.
The majority began its analysis by reviewing both Tawney and Wellman\(^{185}\) and then shifted its focus to whether the same language—“at the wellhead”—was ambiguous as used in section 22-6-8.\(^{186}\) The Court found the statute ambiguous because the same words, when used in the same industry context, are as ambiguous in the flat-rate statute as they are in a lease.\(^{187}\) The Leggett I Court emphasized that the statute provided no more detail than the Tawney leases did regarding gas valuation, royalty methodology, or cost allocation in particular.\(^{188}\) This lack of guidance gave rise to uncertainty, as there may be more than one way lessees could comply with the statute.\(^{189}\) Therefore, the majority found the flat-rate statute ambiguous.\(^{190}\)

The Leggett I Court next sought to discern section 22-6-8’s legislative intent in order to give the flat-rate statute its proper effect.\(^{191}\) The majority found that section 22-6-8 was enacted to right past wrongs, as revealed in the legislative findings and declarations "indelibly engraved into the statute itself."\(^{192}\) Although the statute would achieve its goal of providing mineral owners with adequate compensation regardless of whether the “marketable product” or “at the wellhead” rule was adopted,\(^{193}\) the Court believed it would have been “perversely inconsistent” for a “Legislature so passionately dedicated to ensuring the future flow of adequate compensation to oil and gas landowners to have purposefully provided a mechanism of royalty valuation specifically designed to curtail that compensation.”\(^{194}\) Accordingly, the Court adopted, by a 3-2 majority, the marketable product rule for flat-rate leases\(^{195}\) and held that royalties paid according to section 22-6-8 must be one-eighth of the of the sale price and cannot be diluted with costs incurred beyond the wellhead.\(^{196}\)

\(^{185}\) Id. at *12–15.
\(^{186}\) Id. at *15.
\(^{187}\) Id.
\(^{188}\) Id. at *16.
\(^{189}\) Id.
\(^{190}\) Id. at *15–16.
\(^{191}\) Id.
\(^{192}\) Id. at *16–17.
\(^{193}\) Id. at *17.
\(^{194}\) Id. at *17–18.
\(^{195}\) Id. at *18. The Court said that, although the implied covenant to market does not apply to the original flat-rate royalty, the statute “unquestionably altered the basis of the parties’ bargain going forward.” Id. at *19. Therefore, the implied covenant to market applied to the wells in question. Id.
\(^{196}\) Id. at *22–23.
Wilson: Without a <em>Leggett</em> to Stand On: Arguing for Retroactive

B. Leggett II

Following <em>Leggett I</em>, EQT petitioned the Court for a rehearing, arguing the Court had misapprehended the applicable law.\(^{197}\) Fortunately for EQT, West Virginia Supreme Court Justice Brent Benjamin, <em>Leggett I</em>’s author, lost his 2016 re-election bid to Justice Beth Walker, who took the bench in 2017.\(^{198}\) The newly comprised Court granted EQT’s petition and withdrew its <em>Leggett I</em> opinion, with Justice Walker serving as the swing vote.\(^{199}\)

Upon rehearing, the <em>Leggett II</em> Court found that the <em>Leggett I</em> majority had misapprehended the applicability of contract principles to statutory interpretation.\(^{200}\) The new majority re-examined <em>Wellman</em> and <em>Tawney</em>\(^{201}\) but found both inapplicable because the driving force behind each—the implied covenant to market—does not append itself to statutes.\(^{202}\)

Free from these common law constraints, the Court resorted to canons of statutory interpretation and again sought the Legislature’s intent in enacting the flat-rate statute.\(^{203}\) The new majority found that section 22-6-8 was enacted to ensure fair and adequate compensation for West Virginia’s mineral owners.\(^{204}\) The <em>Leggett II</em> Court found this intent expressed in plain and unambiguous language, demanding royalties be paid at the wellhead.\(^{205}\) Additionally, the new majority believed the Legislature’s purpose of ensuring adequate compensation for mineral owners would still be achieved when royalties are subject to deductions.\(^{206}\) The <em>Leggett II</em> Court ultimately held that royalties paid according to section 22-6-8 are subject to deductions for post-production expenses and that lessees may use the net-back method when calculating these royalties.\(^{207}\)


\(^{200}\) <em>Leggett II</em>, 800 S.E.2d 850, 855 (W. Va. 2017).

\(^{201}\) Id. at 858–60.

\(^{202}\) Id. at 860–62.

\(^{203}\) Id. at 863.

\(^{204}\) Id. at 864.

\(^{205}\) Id.

\(^{206}\) Id. at 867.

\(^{207}\) Id.
Before concluding, the new majority acknowledged that this holding stood in direct contrast to Tawney and the rules governing freely negotiated leases;\(^\text{208}\) it felt this divergence was the inevitable result of applying two different canons of construction, however.\(^\text{209}\) Nevertheless, the Leggett II Court invited the West Virginia Legislature to clarify its intent regarding whether section 22-6-8 allows lessees to charge lessors for post-production expenses:

> [T]his Court recognizes the inherent tension between holders of leases subject to our interpretation of West Virginia Code § 22-6-8 and those freely-negotiated leases which remain subject to the holdings of Wellman and Tawney. **We therefore implore the Legislature to resolve the tensions** as it sees fit inasmuch as this Court may only act within the confines of our constitutional charge.\(^\text{210}\)

Justice Margaret Workman, who joined the majority opinion, concurred to emphasize that lessees must not abuse the right to deduct certain expenses and urged the Legislature to enact provisions ensuring that lessors are not charged unreasonable expenses.\(^\text{211}\) Most notably, Justice Workman echoed the new majority by inviting the Legislature to clarify whether section 22-6-8 permits post-production expenses to be deducted from royalties:

> What both the foregoing and the majority’s opinion underscores is the necessity of the Legislature to address these policy-laden issues and declare, by statute, the will of the State’s citizenry in this regard. This Court is constrained to our canons of statutory construction and does not make policy. . . . Where the Legislature’s inaction in the face of such significant changes in the industry leaves this Court to intuit its intentions and/or retrofit outdated statutory language to evolving factual scenarios, the will of the people is improperly disregarded.\(^\text{212}\)

\(^{208}\) *Id.* at 868.

\(^{209}\) *Id.* at 868–69.

\(^{210}\) *Id.* at 869 (emphasis added).

\(^{211}\) *Id.* (Workman, J., concurring). The Legislature responded by enacting West Virginia Code section 37C-1-1, better known as the “Check Stub Bill.” Andrew Graham, *West Virginia, 4 Oil & Gas, Nat. Res., & Energy J.* 463, 470 (2018). This statute requires lessees to provide each lessor specific information relating to production, such as production date, volume of hydrocarbons produced, and price each product sold for; in the event a lessee does not provide this information, the statute confers a cause of action upon the lessee for disclosure and the right to reasonable attorneys’ fees. See *W. VA. CODE ANN.* § 37C-1-1 (West 2018).

\(^{212}\) *Leggett II,* 800 S.E.2d at 871 (Workman, J., concurring).
The Court’s expressed invitations indicated the 2018 West Virginia Legislative Session would be a bellwether moment for mineral owners, as the Legislature was tasked with clarifying whether the Leggett II Court’s interpretation of section 22-6-8 was correct.213

C. Legislative Response to Leggett II: Senate Bill 360

The Legislature immediately responded to the Court’s invitations to clarify whether section 22-6-8 allows deductions for post-production expenses. On January 24, 2018, Senate Bill 360 was introduced in the West Virginia Senate.214 The bill’s short title stated it was “clarifying oil and gas permits not [to] be on flat well royalty leases.”215 Senate Bill 360 proposed to change the statute’s royalty basis from the “total amount . . . at the wellhead” to “the gross proceeds, free from any deductions for post-production expenses, received at the first point of sale to an unaffiliated third-party purchaser in an arm’s length transaction.”216 The bill also included a note that stated “[t]he purpose of this bill is to clarify the royalty owed to a royalty owner in an oil and gas lease.”217

While enacting Senate Bill 360, several Senators explained that the bill was a response to Leggett II’s invitations to clarify the law. For example, Senator Randy Smith expressed his understanding that Leggett II said “the Legislature need[ed] to clarify the law because it was unclear.”218 He further explained that Leggett II’s invitations were the catalyst for Senate Bill 360.219 Similarly, Senator Michael Romano, after discussing the confusion produced by the pair of Leggett decisions, reiterated that the Court “invited [the Legislature] to straighten it out one way or another.”220 While being voted on in the Senate, Senator Charles Trump declared that Senate Bill 360 would “reverse or nullify, redefine the outcome of [Leggett II]” and prohibit lessees from deducting post-production expenses.221 The Senate passed Senate Bill 360—by a vote of 34-0—on February

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215 Id.
216 Id.
217 Id.
219 Id. at 8:37:24.
220 Id. at 8:56:18.
282 The House of Delegates then passed the bill with a vote of 96-2. Governor Jim Justice signed Senate Bill 360 into law on March 9, 2018, ensuring mineral owners will receive one-eighth of the gross proceeds, free from post-production expenses.

VII. SECTION 22-6-8, AS AMENDED BY SENATE BILL 360, OVERRULED LEGGETT II AND APPLIES RETROACTIVELY

Part VII argues that section 22-6-8, as amended by Senate Bill 360, clarified the statute’s prohibition on post-production expenses and therefore applies retroactively. Section A explains how natural gas companies dilute royalties by carefully structuring their businesses in such a way that maximizes the amount of deductible expenses, while Section B illustrates that the net-back method is used to deny mineral owners adequate compensation. Next, Section C proves that the net-back method works an unjust hardship on mineral owners. Finally, Section D argues that Senate Bill 360 clarified section 22-6-8’s prohibition of post-production expenses and therefore applies retroactively.

A. The Net-Back Method in Practice

At first blush, the net-back method may sound like an equitable way to allocate costs between lessor and lessee; however, lessees use the net-back method to fleece lessors of their valuable minerals. Gas companies—EQT in particular—best effectuate this by creating wholly-owned subsidiary companies that charge the mineral owner with what would be otherwise impermissible deductions.

EQT Corporation, the parent company, utilizes three main subsidiaries while producing natural gas. First, EQT Production Company (“Production”)
is responsible for leasing property and, as lessee, drilling for and producing natural gas.\textsuperscript{231} Production then sells the gas to EQT Energy, L.L.C., (“Energy”) at the wellhead.\textsuperscript{232} Energy relies on EQT Gathering, L.L.C., (“Gathering”) to gather and transport the gas until Energy sells it to a downstream buyer.\textsuperscript{233}

These relationships become even more convoluted, and at times intertwined, once payments are due. The best way to fully appreciate these intricacies is to work backwards, beginning downstream, and finishing at the wellhead. Energy ultimately sells the gas to an unaffiliated third-party buyer, where it receives the gross proceeds.\textsuperscript{234} Gathering then charges Energy for its transportation services,\textsuperscript{235} based on an annual rate that Gathering sets;\textsuperscript{236} Energy pays Gathering by deducting the gathering and transportation costs from the gross proceeds and is left with the net proceeds.\textsuperscript{237} Energy pays the net proceeds to Production, which it claims to be the “wellhead price.”\textsuperscript{238} Production uses the net proceeds—instead of the gross proceeds—to calculate the mineral owner’s royalty.\textsuperscript{239}

Interestingly, EQT Corporation (“EQT”) appears absent from the entire process, from well to sale. This is not because EQT is uninvolved with its subsidiaries, but quite the opposite. EQT uses these subsidiaries as alter egos to avoid paying the full royalties owed to mineral owners.\textsuperscript{240} EQT restructured its business—forming these subsidiaries—following \textit{Wellman’s} holding that the mineral owner’s royalty must be based on the first point of sale.\textsuperscript{241} EQT relies on the fallacy that these intra-company sales are arm’s-length transactions among independent entities, allowing it to base royalties on the wellhead sale between

\begin{thebibliography}{99}
\bibitem{footnote3} Order Resolving Motions, \textit{supra} note 231, at 41; Alter Ego Order, \textit{supra} note 230, at 3.
\bibitem{footnote4} Alter Ego Order, \textit{supra} note 230, at 3.
\bibitem{footnote5} Dep. Transcript of Kristy Toia, \textit{supra} note 232, at 124:6-10. Gathering, as well as the other EQT entities, uses “EQT Midstream” as a fictitious trade name. Defendants’ Motion for Disqualification of Judge Timothy Sweeney at 1 n.1, Goff v. EQT Corp., No. 16-C-22 (W. Va. Ct. Ct. Ritchie Cnty. Jan. 15, 2021); \textit{see also} Alter Ego Order, \textit{supra} note 230, at 3.
\bibitem{footnote6} Dep. Transcript of Kristy Toia, \textit{supra} note 232, at 50:6–10.
\bibitem{footnote7} Alter Ego Order, \textit{supra} note 230, at 3. Energy engages in a legal fiction at this point in the calculations. Rather than using the actual price received by a third-party purchaser in an arm’s-length transaction as the gross proceeds, Energy uses an index price for the value of gas at the interstate pipeline. \textit{Id.}
\bibitem{footnote8} \textit{Id.}
\bibitem{footnote9} \textit{Id.} at 4.
\bibitem{footnote10} \textit{Id.} at 13.
\end{thebibliography}
Production and Energy. This position is indefensible because these entities are one and the same. EQT and its subsidiaries act in unison and assign profits to each group. The entities then agree to a consolidated business plan with the aim of doing what is best for EQT. Any profits the subsidiaries accrue ultimately make their way back to EQT Corporation, as the parent company controls what capital each subsidiary may own.

B. The Net-Back Method Provides Wholly Inadequate Compensation to Mineral Owners

Gas companies claim the net-back method is a fair way of allocating to mineral owners their pro rata share of expenses, but this pays mere lip service to the idea of equity. Instead, lessees carefully structure their businesses—by forming alter egos—in order to maximize the amount of deductions that can be taken, thereby diluting the mineral owner’s royalty payment. Such a scheme enables the lessee to dictate how much the lessor’s royalty will be, to the point he receives wholly inadequate compensation for his valuable minerals.

Proponents of the net-back method argue that mineral owners should not fret about gas companies inflating costs because the latter is responsible for the remaining seven-eighths. This position is incorrect because it fundamentally misunderstands how the net-back method works in practice. While the total costs are in fact a zero-sum game, which costs are deductible remains in flux. Each subsidiary, Production, Energy, and Gathering, are best thought of as departments, amongst which EQT’s total costs must be distributed. Because

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242 Order Resolving Motions, supra note 231, at 41 (referring to these intracompany sales as “the fly in the ointment” of EQT’s business model); Alter Ego Order, supra note 230, at 5; see also W.W. McDonald Land Co. v. EQT Prod. Co., 983 F. Supp. 2d 790, 804 (S.D. W.Va. 2013) (“[EQT] cannot calculate royalties based on a sale between subsidiaries at the wellhead when the defendants later sell the gas in an open market at a higher price. Otherwise, gas producers could always reduce royalties by spinning off portions of their business and making nominal sales at the wellhead.”).

243 Order Resolving Motions, supra note 231, at 50 (finding that the subsidiaries “have corporation or LLC behind their names but are not real companies, but follow their parent’s orders and directions.”); Alter Ego Order, supra note 230, at 5.

244 Order Resolving Motions, supra note 231, at 45.

245 Id.

246 Id. at 55.

247 See, e.g., Leggett II, 800 S.E.2d 850, 866 (W. Va. 2017); Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1158 (Pa. 2010) (“While [lessors] present a concern that gas companies may inflate their costs to drive down the royalties paid, we find that claim unconvincing because gas companies have a strong incentive to keep their costs down, as they will be paying seven-eighths of the costs.”).
Production’s costs are not deductible.\textsuperscript{248} EQT has no incentive to allocate expenses to Production. On the other hand, every expense Gathering accounts for can be charged to the mineral owner as a post-production expense,\textsuperscript{249} thereby incentivizing EQT to assign Gathering as many expenses as possible. Unsurprisingly, EQT does exactly that. The rate that Gathering charges includes not only the costs of gathering and transporting the gas but also meals and entertainment, uniforms, meter operations and repair, personal property taxes,\textsuperscript{250} salaries, retirement, medical insurance, and office supplies.\textsuperscript{251}

EQT effectively treats mineral owners as business partners that have agreed to shoulder not only the costs of marketing natural gas but also those associated with running the corporate entity. Such treatment is inconsistent with the lessor’s true relationship to the lessee: the former merely supplies a raw material and, in exchange, receives a portion of the sale proceeds.\textsuperscript{252} Unsurprisingly, mineral owners are left feeling the net-back method’s harsh effect. In some instances, EQT’s deductions exceeded the sales proceeds,\textsuperscript{253} meaning the mineral owner owed EQT for selling his valuable minerals.\textsuperscript{254} The net-back method leaves mineral owners stripped of their minerals without payment and is the “wholly inadequate compensation” the flat-rate statute intended to eradicate.

\textit{C. The Net-Back Method Works an Unjust Hardship on Mineral Owners}

Allowing lessees to deduct post-production expenses via the net-back method works an unjust hardship on mineral owners for several reasons. For


\textsuperscript{249} See Order Resolving Motions, supra note 231, at 41.


\textsuperscript{251} Transcript of Trial, supra note 8, at 150–52.

\textsuperscript{252} \textit{Accord Leggett I}, No. 16-0136, 2016 W. Va. LEXIS 890, at *21 (W. Va. Nov. 17, 2016) (“In a properly functioning royalty system, lessor-owners of oil and gas interests are accurately cast as suppliers of raw materials necessary to develop a finished product. For such raw materials, such lessor-owners are paid a one-eighth proportionate price accounted for as a cost of goods sold. Lessor-owners do not sign on to be the lessee’s business partner or a participant in a joint venture with the lessee, and they should not be compelled to assume risks or expenses that would typically be associated with that sort of role.”).

\textsuperscript{253} Dep. Transcript of Kristy Toia, supra note 232, at 117:6–22.

\textsuperscript{254} This is especially egregious conduct. EQT claims to sell the gas at a loss, despite West Virginia’s recognition of the “cessation of production doctrine.” This doctrine allows a lessee to temporarily halt production if the reason for doing so is incidental to normal operation of the lease. Bryan v. Big Two Mile Gas Co., 577 S.E.2d 258, 266 (W. Va. 2001). Further, a lease will not terminate for lack of production if the lessee has a good faith belief that operations will be profitable in the future. Lowther Oil Co. v. Miller-Sibley Oil Co., 44 S.E. 433, 436 (W. Va. 1903).
starters, lessees will naturally deduct expenses that are either unreasonable or not actually incurred. This, in turn, places mineral owners in a bind. Savvy lessors, who realize their royalties are being diluted, will look to pursue legal action. Unfortunately, some mineral owners will be unable to hire counsel because their damages—the amount of improper deductions—are not enough to warrant a lawsuit. Based on these realities, gas companies perform a cost-benefit analysis when deciding what expenses to deduct from royalties. The result is unsurprising: the company makes a calculated business decision to deduct as many post-production expenses as possible.

Mineral owners that have the resources to litigate royalty disputes still face an uphill battle. Lessees that shortchange their lessors’ royalties force the latter to hire an attorney, file suit, and then endure years of litigation, an act the West Virginia Supreme Court has expressly warned against. Lessors face yet another hurdle during discovery when they must parse through the lessee’s intra-company sales records. Improper expenses are often artificially inflated and hidden under less suspicious line items, impeding the fact-finding process.

255 Lustgarten, supra note 19.
258 See W.W. McDonald Land Co. v. EQT Prod. Co., 983 F. Supp. 2d 790, 816 (S.D. W. Va. 2013); EQT also deducts severances taxes from lessors’ royalties, despite the fact that West Virginia Code section 11-13A-3(a) clearly places this responsibility on the producer alone. Dep. Transcript of John Bergonzi at 276:18–20, Kay Co. v. EQT Prod. Co., No. 1:13-CV-151 (N.D. W. Va. Aug. 17–18, 2018). This practice is simply indefensible. Under West Virginia law, the lessor is not responsible for paying any portion of severance taxes. Transcript of Trial, supra note 8, at 201 (ruling that EQT’s decision to charge the lessor for severance taxes is erroneous as a matter of law).
259 Patrick Leggett, the named plaintiff in the Leggett decisions, endured four and half years of litigation before passing away on May 7, 2017, a mere 19 days before Leggett II was decided. Patrick D. Leggett, PARKERSBURG NEWS & SENTINEL (May 9, 2017), https://www.newsandsentinel.com/obituaries/2017/05/patrick-d-leggett/. Similarly, Garrison Tawney, the named Plaintiff in Estate of Tawney v. Columbia Natural Resources, L.L.C., passed away at age 90, three years prior to his case making it before a jury. HUR HERALD (Sept. 16, 2004), http://www.hurherald.com/obits.php?id=12700.
262 Anderson, supra note 65, at 602–03.
Deciphering these records is a daunting task that even the nation’s best forensic accountants struggle to perform. Consequently, royalty disputes often become a battle of the experts, and the lessor’s expert maximizes the amount of improper deductions found, while the lessee’s expert minimizes the same. In the end, the lessor receives damages that are a product of compromise, either by settlement or court order. Results such as this further injure minerals owners because gas companies are incentivized to inflate their purported costs with the aim of finding a more favorable middle ground in future disputes. This behavior—artificially inflating costs in order to better the bottom line—works an unjust hardship on all mineral owners, especially those who do not have the means to vindicate their rights.

D. Senate Bill 360 Clarified Section 22-6-8’s Prohibition of Post-Production Expenses and Applies Retroactively

Although there is a general presumption against retroactive legislation, statutory amendments that clarify existing law apply retroactively. Indeed, statutory amendments do not ipso facto constitute a substantive change in the law. The legislature, for instance, may amend the existing law to make its original intent unmistakably clear. Clarifying amendments, therefore, are no more retroactive than a judicial determination construing and applying a statute because each merely states what the law is and has always been.

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263 Lustgarten, supra note 19.
264 Anderson, supra note 65, at 602–03.
265 Id. at 602.
266 W. Va. Code Ann. § 2-2-10 (West 2017) (allowing statutory amendments to be applied retroactively when the legislative intent is apparent from the context); Piamba Cortes v. Am. Airlines, Inc., 177 F.3d 1272, 1283 (11th Cir. 1999) (“[When an] amendment clarifies prior law rather than changing it, no concerns about retroactive application arise and the amendment is applied to the present proceeding as an accurate restatement of prior law . . . [because] an amendment containing new language may be intended ‘to clarify existing law, to correct a misinterpretation, or to overrule wrongly decided cases.’”) (quoting United States v. Sepulveda, 115 F.3d 882, 885 n.5 (11th Cir. 1997)); Leshinsky v. Telvent GfT, S.A., 873 F. Supp. 2d 582, 590 (S.D.N.Y. 2012) (“Notwithstanding th[e] presumption [against retroactive legislation], several [courts] have held that when an amendment merely clarifies existing law, rather than effecting a substantive change to the law, then retroactivity concerns do not come into play.”); Brown v. Crum, 400 S.E.2d 596, 599 (W. Va. 1990) (per curiam) (retroactively applying a statutory amendment intended to clarify the Legislature’s original intent); State Auto. Mut. Ins. Co. v. Youler, 396 S.E.2d 737, 750–51 (W. Va. 1990) (same).
268 Id.
269 First Nat’l Bank of Chi. v. Standard Bank & Tr., 172 F.3d 472, 478 (7th Cir. 1999) (quoting Pope v. Shalala, 998 F.2d 473, 483 (7th Cir. 1993)).
There is no bright-line test to determine whether an amendment clarifies existing law.\footnote{Levy v. Sterling Holding Co., 544 F.3d 493, 506 (3d Cir. 2008) (quoting United States v. Marmolejos, 140 F.3d 488, 491 (3d Cir. 1998)).} Factors to consider include: (1) whether the legislature declared that it was clarifying a prior enactment; (2) whether a conflict or ambiguity existed prior to the amendment; and (3) whether the amendment is consistent with a reasonable interpretation of the prior enactment.\footnote{Middleton v. City of Chicago, 578 F.3d 655, 663–64 (7th Cir. 2009).} Declarations found in the amendment’s legislative history may be relevant to the analysis, especially if those statements are consistent with a reasonable interpretation of the prior enactment.\footnote{Piamba Cortes v. American Airlines, Inc., 177 F.3d 1272, 1284 (11th Cir. 1999) (citing Sykes v. Columbus & Greenville Ry., 117 F.3d 287, 293–94 (5th Cir. 1997)); Liquilux Gas Corp. v. Martin Gas Sales, 979 F.2d 887, 890 (1st Cir. 1992) (using the “legislature’s expression of what it understood itself to be doing” to determine whether an amendment clarified the law).} The fact that an amendment conflicts with a judicial interpretation of the prior enactment is not dispositive; the amendment may be intended to clarify a conflict that resulted from the judicial interpretation.\footnote{Levy, 544 F.3d at 507.}

The West Virginia Legislature passed Senate Bill 360 to clarify section 22-6-8’s prohibition on post-production expenses. Although section 22-6-8, as amended by Senate Bill 360, does not expressly state that it clarified the law following the Leggett decisions, or overruled Leggett II, the context surrounding its enactment proves this was the Legislature’s intent. First, Leggett II diverged from Leggett I’s interpretation of the flat-rate statute, conflicting whether “at the wellhead” allows lessees to deduct post-production expenses.\footnote{Compare Leggett I, No. 16-0136, 2016 W. Va. LEXIS 890, at *3–4 (W. Va. Nov. 17, 2016) (prohibiting natural gas companies from deducting post-production expenses from flat-rate royalties), with Leggett II, 800 S.E.2d 850 (W. Va. 2017) (allowing natural gas companies to deduct post-production expenses from flat-rate royalties).} Senate Bill 360 was enacted to resolve this conflict. Second, section 22-6-8, as amended by Senate Bill 360, is consistent with a reasonable interpretation of the original enactment. The Leggett I Court interpreted the original enactment to demand that royalties be paid on the gross proceeds received, free from post-production expenses.\footnote{Leggett I, 2016 W. Va. LEXIS 890, at *16–17.} Senate Bill 360 codified this interpretation of section 22-6-8. Third, the Leggett II Court, after recognizing these conflicting results, implored the Legislature to clarify the law and “declare, by statute, the will of the State’s citizenry.”\footnote{Leggett II, 800 S.E.2d at 871 (Workman, J, concurring).}

Senate Bill 360’s legislative history confirms the Legislature’s intent to clarify, rather than alter, section 22-6-8. To begin with, the Legislature acted in response to Leggett II’s invitations to clarify the law; indeed, Senate Bill 360 was...
passed the very next legislative session. Several pieces of legislative material also prove that Senate Bill 360 was intended to clarify the law, including the note attached at introduction that stated the bill was “clarify[ing] the royalty owed.” Senate Bill 360’s short title—declaring that it was “clarifying oil and gas permits not [to] be on flat well royalty leases”—reaffirms this conclusion. Equally significant are the declarations of several Senators, each recognizing that Senate Bill 360 was in response to, and intended to overrule, Leggett II. Senators Smith and Romano each explained that Senate Bill 360 was a direct result of the Supreme Court imploring it to clarify whether section 22-6-8 permits post-production expenses. Senator Trump’s remarks are even more telling: he unequivocally stated that the Legislature was overruling Leggett II. These facts confirm that Senate Bill 360 clarified section 22-6-8 and, consequently, overruled Leggett II.

VIII. CONCLUSION

In conclusion, the West Virginia Legislature undoubtedly passed Senate Bill 360 intending to clarify that lessees are prohibited from deducting post-production expenses from royalties paid according to section 22-6-8. The Legislature enacted the flat-rate statute to ensure that mineral owners receive their fair share of compensation for their valuable minerals. Despite this, natural gas companies have carefully crafted their businesses to dilute royalties owed to West Virginia’s mineral owners, such as the Richardses.

Although the West Virginia Supreme Court held that lessees may deduct post-production expenses in Leggett II, the Court implored the Legislature to clarify section 22-6-8 in light of changing industry regulations and customs. The Legislature responded by passing Senate Bill 360: this bill expressly prohibited lessees from deducting post-production expenses when calculating natural gas royalties. Further, Senate Bill 360 clarified, as opposed to altering, the existing law, as shown by the bill’s legislative history. Therefore, section 22-6-8, as amended by Senate Bill 360, applies retroactively and overruled Leggett II.

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278 Id.
279 Id.
280 See sources cited supra notes 218–220 and accompanying text.
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