Institute for **ENERGY LAW**

THE CENTER FOR AMERICAN AND INTERNATIONAL LAW

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# THE ENERGY DISPATCH

A PUBLICATION OF THE IEL YOUNG ENERGY PROFESSIONALS COMMITTEE

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*The Energy Dispatch*, the IEL's Young Energy Professional newsletter, contains substantive articles on trending legal issues in the energy industry, interviews, and professional development.

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## Young Energy Professionals Highlight – Julia Valencia, Legal Counsel, Global Legal/Legal-Americas, Topsoe, Inc.

Interview by Barbara Light, Norton Rose Fulbright US LLP

**BL: What was your path towards becoming a lawyer?**

**JV:** The law always drew my attention because I love to read and write. However, I was unsure of the time and financial commitment when I graduated from college, so instead of diving into law school, I did something completely different and moved to Spain to teach English and earned my Master's in Bilingual Education. After two years in Madrid, I decided to take the plunge into law school. When entering into law school, I did not know what kind of lawyer I wanted to be. All I knew is that I eventually wanted to connect my international background with my legal career.

**BL: How would you describe your practice?**

**JV:** I am thrown into a variety of issues on a day-to-day basis. However, as a commercial attorney a lot of my practice entails negotiating contracts from NDAs to technology licenses to equipment and catalysts supply agreements in both Spanish and English as I support our Latin America office as well as the U.S.

**BL: What do you enjoy most about working in-house?**

**JV:** One of the things I enjoy most about working in-house is being the attorney to help get a deal together that represents the best interests of the company in a sale. Contract negotiations are huge puzzles that involve so much coordination and organization of both hard skills and soft skills. Additionally, I love learning about the business and getting to work closely with non-lawyers on reaching a deal. I have learned so much from some of the members of the commercial team who are some of the brightest engineers I've ever met.

**BL: As in-house counsel, do you have any tips or advice for how young lawyers working with outside counsel can assist you in your role?**

**JV:** I think it is important for outside counsel to know their client's business so they can assess how the legal risks of what is probably a nuanced issue apply to the business. I would recommend looking at their client's website and studying what they sell, then researching what are some common legal issues that may pop up with that industry or product. There have been times where outside counsel has given me a whole laundry list of issues without emphasizing which ones are actually applicable to the business or brought up a solution that is not feasible for the business, and that was not helpful at all. If they had studied our business and what we do, we could have avoided that.

**BL: Do you have any advice for young lawyers seeking a career in-house?**

**JV:** For young lawyers seeking a career in-house, I would recommend reaching out to other in-house attorneys that work in a company or industry that you aspire to work in. Don't be shy about asking them if you could have a few minutes of their time just to learn how they got to where they are but also show gratitude, as one of the most generous gifts someone can give you is their time.

**BL: What do you like to do when you are not working?**

**JV:** When I am not working I am most likely spending time with my family which typically includes, but is not limited to: reading to or playing with my daughter, Laura, we're avid Pete the Cat and Eric Carle fans; enjoying a nice conversation with my husband (which usually gets cut short if our toddler is around); and planning for the arrival of our second daughter in June. I also serve as the family chef, dog walker, stylist, house manager, historian, and social events coordinator. When I'm not doing that, I'm listening to or reading a book recommendation from Goodreads or working out.

## Expert Interview with Kurt Strunk, Vice President, Charles River Associates

Interview by Baldomero Casado, Foley Hoag LLP

*Kurt G. Strunk is a Vice President at Charles River Associates. He is a seasoned energy and finance expert with 30 years of experience working in energy disputes and as an advisor to energy companies, governments, and regulators. He has provided expert testimony at trial over 40 times and written reports on over 100 occasions in international and domestic arbitration, litigated court disputes, and adversarial regulatory proceedings. Mr. Strunk has addressed the quantum of damages in construction disputes, breach-of-contract cases, and alleged expropriations. He has also testified on asset and contract valuation, mergers and acquisitions, regulatory reform, cost of capital, pipeline access, and the design of competitive energy markets. Mr. Strunk has deep expertise in the energy sector, including oil and gas production, midstream pipelines and electric transmission, power plants (solar, wind, hydro, nuclear, and conventional coal and gas), wholesale and retail markets for power and gas, upstream and downstream oil markets, and distributed energy resources such as rooftop solar. He has led due diligence and valuation exercises in support of investors in a variety of power, oil, and gas M&A transactions.*

### BC: How did you become an energy expert? What came first, finance or energy?

**KS:** Finance came first. I began my career as a consulting economist in the early 1990s. For the first two years, I crunched numbers, calculating damages in securities litigation, mainly fraud on the market claims and some broker-dealer disputes. It was great training because I had to be ready for a team of talented lawyers and experts to pick apart the analysis and this finance training taught me to produce litigation-quality work product.

But I quickly transitioned to energy and that happened, coincidentally, because I was in the right place at the right time. I happened to be working at a firm of economists when the energy sector faced major changes, creating the need for economists' input into structural and regulatory reform. When I began my career, the state-owned monopoly power providers in England and Wales had just been broken up and privatized. The power generation business, previously regarded as a natural monopoly, was suddenly opened up to competition. Older, less-efficient coal-fired power plants were shuttered and new, more efficient, and cleaner natural gas plants replaced them. The success of the restructuring process in the UK led the regulator in California to publish its April 1994 Blue Book outlining how California would restructure its power sector and introduce competition. Two years later, the Federal Energy Regulatory Commission issued Order 888, strengthening the framework for competitive power in the US.

After the 1994 release of the Blue Book, a leading economist from England, Sally Hunt, who had been instrumental in the England and Wales restructuring, put together a team to advise on the restructuring process in California. She recruited me that same year and I was soon living in Los Angeles and working on sector restructuring and the design of a new, competitive power market.

The assignment in California led to many subsequent engagements advising on power sector restructuring in other states in the US and in Latin America. By 1998, I was engaged as an advisor to the Mexican Ministry of Energy on power sector restructuring. But that assignment not only involved the restructuring of the Comisión Federal de Electricidad, it also addressed how competitive power generators would procure gas supply from PEMEX. From that point onward, my focus was not only on power, but also on oil and gas.

### BC: Would you please describe your practice and the type of projects you advise on?

**KS:** My practice is a healthy mix of transaction advisory, domestic and international disputes, and regulatory matters. The disputes and advisory elements reinforce one another. Dispute work makes you keenly aware of what can go wrong and problems that arise, for example, with incomplete contracts. Doing the work as an advisor in turn gives you a stronger bench presence as an expert witness.

### BC: Tell me about the transaction advisory side. What type of advice do you provide?

**KS:** My team offers a variety of services to investors and companies engaged in M&A activity in the energy sector. Sometimes that work focuses on regulatory due diligence, answering questions such as: Are the assumptions in the financial model that pertain to outcomes of future regulatory proceedings reasonable? What regulatory risks exist and what is the scale of those risks. In the case of unregulated assets, the work may focus on market due diligence. The investor might want help understanding competitive dynamics in the market, understanding the rules of the market and likely market outcomes. I have also been an expert witness in proceedings seeking regulatory approval. One role of an expert in those cases is to explain how the transaction will affect customers of the regulated entity and whether there will be a net benefit or at least no harm to customers.

**BC: Turning now to your disputes practice, it involves domestic and international disputes. How does working on international disputes differ from doing the same domestically?**

**KS:** While the technical skills—e.g., discounted cash flow analysis or other valuation approaches—tend to be the same, the international work requires additional skills. Adaptability and cultural awareness can be critical when working on international disputes. Facing a tribunal comprised of individuals with multiple nationalities, the expert must be aware of cultural differences and attuned to differences in perspectives and industry customs and practices across geographies. Having myself attended INSEAD, a global MBA program with students from over 160 nations, I had early exposure to the multi-national and multi-cultural environment that permeates the world of international disputes.

International work also requires a broad understanding of international energy policies and markets. Unlike the situation in the US that has long favored private ownership of energy assets, many of the investor-owned energy assets outside of the US were part of the wave of privatizations that began in the UK in the 1980s and accelerated across the globe in the late 1980s and early 1990s. An understanding of this evolution, familiarity with the concession frameworks that accompanied the privatizations, and the creation of multi-national and multi-dimensional energy companies can often be important for an expert to put elements of current international disputes into context.

**BC: Given your experience advising on a wide range of areas within the energy sector (including oil and gas, pipeline access, electricity generation, and renewables), which area do you perceive as having the highest potential for disputes in the near future?**

**KS:** The energy transition requires a scale of capital investment on a new level relative to past investment cycles. The capital required is in the trillions of dollars. In light of supply-chain issues that linger following the COVID-19 pandemic, high levels of inflation, and a volatile geopolitical environment, I expect project delays and project cancellations to trigger new disputes. Many of these could be commercial disputes, but others could be investor-state.

That's not to say there won't be disputes related to traditional energy investments in oil and gas and mining. Those will continue in addition to the energy transition related disputes.

**BC: Finally, what do you enjoy the most about your job?**

**KS:** While I love the variety of the work that my team takes on, most important is the people I meet. These cases require the creation of multi-disciplinary teams, and it is amazing to see how engineers, economists, lawyers, and energy executives can come together and deliver high-value results. Whether that's winning an international arbitration, closing a merger, or breaking ground on a new energy project, the amount of work put in to get there and the collaboration required amongst team members is formidable. I most appreciate working side-by-side with intelligent and dynamic colleagues and learning about them as people.

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## Two Circuits, One Unambiguous Clause: Applying the Same Cost-Deduction Language Across Jurisdictions

Katherine Raunikar, BakerHostetler LLP

Two federal circuit courts recently interpreted identical lease language governing the deduction of post-production costs. Although the governing law in each case had a different default rule on post-production cost deductions, the courts noted that the leases' language unambiguously replaced those default rules. The cases serve as a cautionary tale for what can happen if parties specify in a lease what is a "marketable" product.

### The Lease Language – Market Enhancement Clauses

The language at issue originates from leases with a Market Enhancement Clause ("Clause"), which generally prohibits deductions to create a "marketable" product but allows deductions for enhancing the value of that already "marketable" product:

> It is agreed between the Lessor and Lessee that, notwithstanding any language contained . . . above, to the contrary, all royalties or other proceeds accruing to the Lessor under this lease or by state law shall be without deduction directly or indirectly, for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder to transform the product into marketable form; however, any such costs which result in enhancing the value of the marketable oil, gas or other products to receive a better price may be proportionally deducted from Lessor's share of production so long as they are based on Lessee's actual cost of such enhancements.

*The Grissoms, LLC v. Antero Res. Corp.*, --- F.4th ----, No. 24-3676, 2025 WL 984418, at *3 (6th Cir. Apr. 2, 2025); *Corder v. Antero Res. Corp.*, 57 F.4th 384, 390 (4th Cir. 2023).

### Sixth Circuit Interpretation under Ohio Law

In *The Grissoms, LLC v. Antero Resources Corporation*, gas underwent three stages in post-production: (1) separating crude oil and wellhead gas (selling the oil), (2) processing the wellhead gas to obtain methane (e.g., residue gas) and Y-Grade (selling or transporting residue gas for sale), and

(3) fractionating the Y-Grade into ethane, propane, butane, and natural gasoline (selling or transporting constituent natural gas liquids for sale). 2025 WL 984418, at *2; *see also* 8 WILLIAMS & MEYERS, OIL AND GAS LAW SCOPE (defining "Y-grade mixture" as "[a] liquid hydrocarbon mixture that exists after the methane has been removed and prior to the term that the liquid hydrocarbons are subject to Fractionation"). Antero paid landowners royalties from the sales' "gross proceeds," from which the Clause permitted certain post-production cost deductions. *Id.*

The question was whether Antero "properly deducted from the landowners' royalties the costs to 'process' the natural gas (separating methane from the other gas products) and to 'fractionate' the remaining [Y-Grade] (separating the non-methane gas into its constituent parts)" as costs associated with enhancing a marketable product. *Id.* at *4. Ohio law has no default rule on post-production costs; the "terms of the written instrument" instead govern. *Id.* at *3 (quoting *Lutz v. Chesapeake Appalachia, L.L.C.*, 148 Ohio St.3d 524, 71 N.E.3d 1010, 1012 (Ohio 2016)).

The Sixth Circuit affirmed the lower court and held that the Clause unambiguously prohibited these deductions because they "transformed" the products into "marketable form," rather than "enhancing" them. *Id.* It first found that wellhead gas was not "marketable" because it had no existing or futures market, unlike methane. *Id.* Because wellhead gas was not marketable until processed, in the court's view, costs transforming it into methane were not deductible. *Id.* Similarly, because Y-Grade "is not suitable for buyers in the main" and the producer did not show a "traditional end user" would find Y-Grade "useful," fractionation costs for separating it were not deductible. *Id.* The court rejected the producer's proposed "hypothetical middleman" who would buy wellhead gas because the producer "has not identified any meaningful, sizeable, commercial market for this unrefined gas." *Id.* at *5. As a result, the producer could not deduct fractionation or processing costs from sales of gas products. *Id.*

### Fourth Circuit – West Virginia Law

Under West Virginia leases, a court made a similar holding despite applying the Clause to a different market structure and governing law. In *Corder v. Antero Resources Corporation*, the stages were (1) separation of oil and gas, (2) sending wellhead gas into (a) an interstate pipeline to markets for sale, or (b) a pipeline transferring wellhead gas to a plant to be processed into residue gas and Y-Grade, and (3) either (a) selling the Y-Grade at the processing plant or (b) sending the Y-Grade to a plant to be fractionated into individual natural gas liquid products. 57 F.4th 384, 388–89 (4th Cir. 2023). West Virginia follows the "marketable product" rule, generally prohibiting post-production cost deductions from base royalty. *Id.* at 394 (citing *Estate of Tawney v. Columbia Nat. Res., LLC*, 219 W.Va. 266, 633 S.E.2d 22 (2006)).

Like in *Grissoms*, the *Corder* court held the Clause "has a plain, unambiguous meaning: when Antero pays royalties from the sale of a particular product, it may deduct actual and reasonable costs it incurred after that product became fit for sale, as long as those costs enhanced the value of the product." *Id.* at 401. The court explained that "the plain meaning of 'product,'" when in "marketable form," "refers to the particular form of natural gas that [the producer] sells," so "the Clause focuses on whether the form of gas Antero sells—and on which it must pay royalties—is marketable at the time [the producer] incurs a cost." *Id.* The Fourth Circuit found that the phrase "oil, gas, and other products" (or as the court read it, "oil products, gas products, and other products") means "[t]he Clause is not concerned with when 'gas' first reaches a marketable form, but rather when the particular gas 'product' sold does." *Id.* at 399–400.

The court rejected Antero's reading that the Clause envisioned unprocessed gas could be the "product" from which costs are deducted because "it would make only a singular product—unprocessed gas—relevant." *Id.* at 400. The Court explained the Clause envisions "'processing' costs will not be deductible in some circumstances," but "if the proper reference point is the marketability of unprocessed gas, 'processing' costs will always be deductible." *Id.* "Had Antero instead wished to make the marketability of 'unprocessed gas,' the reference point," the court quipped, "it should have said so." *Id.* at 400. The court then remanded the case so the factfinder could determine "which products Antero sold during the relevant time frame, when those products became marketable, and whether Antero incurred the [processing, fractionation, and transportation] costs before or after that point." *Id.* at 401. The court left the issue of which fractionation and processing costs were deductible to the lower court. *See id.* at 401 n.11.

### Observations

In each case, the court looked at whether the lessee "transformed" a product to marketable form, implying that any time a producer "transforms" one marketable product into another, "transformation" costs are not deductible. In other words, even if a producer shows a viable market exists for wellhead gas, when the producer sells residue gas after processing, those processing costs are not deductible under the Clause. Indeed, the producer in *Corder* did transport wellhead gas directly to a pipeline for sale, but the court seemed to give that no weight. By contrast, in *Grissoms*, the court found no market existed for wellhead gas or Y-Grade (without noting whether any wellhead gas or Y-Grade was sold). This leaves open the question of whether the *Grissoms* court would have decided differently had the producer established that it sold wellhead gas or Y-Grade or that a viable market exists for both products. *But see Grissoms*, 2025 WL 984418, at *3 ("Even if a cost enhances a marketable product, Antero *may not deduct that cost if it is required to make another product—a transformed product—marketable*." (emphasis added)).

In sum, the cases lead to two conclusions. First, under language like that in the Clause, producers must be wary of deducting post-production costs necessary to "transform one product into another"—i.e., processing and fractionation—when the producer also sells the transformed product. Second, the cases appear to foreclose the "first" marketable product's relevance to deductions under such language. In other words, even if a producer sells wellhead gas or Y-Grade, a court may not find that those sales allow processing and fractionation deductions when the producer also sells further processed products.

## Mineral Interest Ownership & Operators under Joint Operating Agreements

Hannah T. Warren, Hogan Thompson Schuelke LLP

### Introduction

The joint operating agreement ("JOA") is one of the most ubiquitous agreements in the oil and gas industry. These agreements govern operations of immense financial risk and reward and establish the scope of the parties' roles and responsibilities, including the confines of the principal role of the Operator.

But what happens when that Operator does not own an interest in property being developed? While it may seem like such a scenario would be rare—who would want to be Operator under a JOA if they did not own an interest?—that is far from the case. Many oil and gas organizations have a set of subsidiaries, each of which serves a different role. Thus, the holding entity of the organization's working interest may differ from the organization's operating entity.

How does this work under typical JOAs? Must an Operator own working interest in the property being operated? Surprisingly, older versions of the AAPL Model Form Operating Agreement (the "Model Form")—the most widely used model form in the United States—do not directly address this issue. There is no express requirement for the Operator to own an interest in the Contract Area in the Model Form. But some courts and commentators have found that an ownership requirement is implied. The lack of an express requirement of ownership interest has created a host of disagreement and confusion in how parties navigate the processes of designating and removing Operators.

This paper discusses mineral interest ownership in relation to the Model Form, how the most recent Model Forms have addressed the requirement, and how an Operator can transfer its ownership.

### The Operator

The Operator is "typically charged with full control over physical operations and administrative activities, including title reviews, record keeping, accounting, acquisition of insurance, litigation management, and regulatory filings." Gary B. Conine, The Joint Operating Agreement: A Legal Analysis (Found. for Nat. Resources & Energy L. 2024) ("Conine"), at § 6.1. Due to the Operator's broad scope of control, the largest working interest owner is often designated as the Operator by the other parties to the JOA, each of whom owns a working interest in the Contract Area. This creates "the practical advantage" of ensuring the Operator "has the same motivation as other participants in the success of the operation and controlling costs." *See id.*

*Mineral Interest Ownership*

Requiring that an Operator own and maintain an interest in the minerals that the JOA governs is not a novel concept and has been consistently discussed in both caselaw and industry publications. *See, e.g.*, Conine, at § 6.1 ("Although many operating agreements do not make it an express requirement, the common practice has been to designate the Operator from among the parties to the agreement, each of whom owns a working interest in the Contract Area."); 63 Rocky Mountain Mineral Law Foundation Institute Chapter 29, "What's Different About the New AAPL FORM 610-2015 Model Form Operating Agreement, And Why Should I Use It?" (July 20, 2017) (discussing the changes made to the 2015 Model Form to retract the ownership requirements, which had historically been part of the Model JOA Form prior to 2015); *Stable Energy, L.P. v. Kachina Oil & Gas, Inc.*, 52 S.W.3d 327, 334 (Tex. App.—Austin 2001, no pet.) ("Stable correctly contends that Kachina was vulnerable to being replaced by a successor operator because, at the time of Anchor's alleged election, Kachina did not own a working interest in the well").

Despite such discussion, though, there is no express requirement for the Operator to own an interest in the Contract Area. *See* AAPL Form 610-1977, -1982 & -1989, art. V.B.1. Rather, over the years, the requirement has been implied from the language in the agreement governing the resignation or removal of the Operator. *See id.* "The implication arises from a declaration that removal is automatic if the Operator no longer owns an interest, subject only to the act of appointing a successor." Conine, at § 6.1.

Departing from the implicit requirement, the Form 610-2015 Model JOA contains an entirely new provision that specifically addresses the Operator's ownership interests: "The Operator shall own an interest in the Contract Area[.]" AAPL Form 610-2015 at Art. V.A. Under the 2015 Model Form, operatorship is intended to be limited to only those parties owning an interest in the minerals that the JOA governs unless the parties agree otherwise. *See id.* If the

Operator does not own an interest in the minerals—i.e., it is a "non-owning operator"—it must have a separate agreement with the interest-owning parties, which is either set forth in one of the Article XVI provisions or in an entirely separate agreement. *See id.* Failing to enter into a separate agreement automatically disqualifies the non-owning Operator from acting as the Operator. *See id.* Needless to say, this can create risks for companies that separate their working interest-owning subsidiary from their operating subsidiary unless steps are taken to address this situation.

These modifications to the Model Form require oil and gas companies that have separate subsidiaries that conduct operations to take steps to address this division. But these changes also help parties to avoid the disagreements that historically plagued the earlier Model Forms, specifically regarding ownership in the context of resignation or removal of Operators. That said, to the extent that an Operator fails to satisfy the ownership requirements upon which the parties agree, the case law interpreting Article V.B. in AAPL Form 610-1989 and addressing resignation or removal would continue to apply.

*Assignment of Interest*

An issue that frequently arises is whether and, if so, how the Operator can assign its interest or role under the JOA to a third party. This is particularly important for companies that employ separate subsidiaries to serve as Operator on their oil and gas projects and may want to assign operatorship rights to those subsidiaries.

The 1989 Model Form is silent as to assignability. The most recent 610-2015 Form, however, does state that "[o]peratorship is neither assignable nor forfeited except in accordance with the provisions of [ ] Article V." AAPL Form 610-2015 at Art. V.A. Under the 2015 Model Form, the assignment through the sale or transfer of an Operator's full interest or an interest in excess of the minimum agreed to by the parties is deemed a "resignation" and triggers the formal selection of successor Operator process. *See id.* at V.B.2, V.B.6. This modification to the most recent Model Form also helps parties to side-step issues when it comes to transfer of interests, especially when it is unclear if the Operator is transferring its interest or merely delegating operatorship functions.

In sum, Operators generally must own and maintain a mineral interest in the Contract Area, which ensures that the parties to the JOA are financially aligned in the success of the operation and minimizing costs. Under the most recent 2015 Model Form, however, the parties may agree to a non-owning Operator, but such an agreement must be expressly agreed either in a separate agreement or in the JOA. In any context, absent language to the contrary, non-operators may risk waiving the formal requirements of mineral interest ownership or selection of a successor Operator, especially if the non-operators prolong bringing suit to oust the successor Operator.

**Conclusion**

Though the most recent Form 610-2015 Model JOA gives certainty to many of the formerly implied requirements under the earlier Forms, the 2015 Model Form is not yet in wide use. Many parties negotiating a JOA today continue to use the 1989 Model Form. Thus, while the 2015 Model Form can be a guiding north star, parties must continue to rely on the caselaw interpreting the earlier Forms. Caselaw is uniformly clear that an Operator, particularly an initial Operator, must own and maintain a mineral interest under the Contract Area to satisfy the formal requirements, absent any language in the JOA.

## Colorado Finalizes New Water Usage Standards for Oil and Gas Operations

Jim Tartaglia, Steptoe & Johnson PLLC

The Colorado Energy and Carbon Management Commission (ECMC or Commission) recently adopted new regulations aimed at limiting freshwater usage, and in turn promoting the use of recycled produced water, to support oil and gas operations across the state (collectively, Rules). This article provides a high-level summary of the Rules.

**Background**

Produced water is any water that is co-produced with hydrocarbons at the wellhead. Depending on several factors, a well operator will either dispose of produced water that it extracts (often by subsurface injection) or instead will recycle or reuse that produced water to support other drilling, completion, or enhanced recovery operations. A primary goal of the Rules is to incentivize the recycling and reuse of produced water by operators, and in turn, decrease the amount of fresh water used in oil and gas development processes.

The impetus for the Rules dates back to House Bill (H.B.) 23-1242 (effective June 7, 2023), which enacted directives focused on the use of fresh water in oil and gas operations. That legislation imposed certain specific reporting requirements, and further mandated that the Commission adopt new regulations "to require a statewide reduction in fresh water usage, and a corresponding increase in usage of recycled or reused produced water, at oil and gas locations." *C.R.S. § 34-60-134(5)(c)(I)*. H.B. 23-1242 also created the Colorado Produced Water Usage Consortium (Consortium), comprised of 31 members representing an array of public and private stakeholders. *See C.R.S. § 34-60-135(2-3*). One of the Consortium's first statutory tasks was to develop a series of recommendations to guide the Commission in its development of the Rules. *See id. at -135(4)*. Based on the

Consortium's recommendations, the statutory directives, and a six-month administrative record with substantial public and industry input, the Commission announced that it had finalized and adopted the Rules on March 12, 2025. The Rules become effective April 30, 2025. *48 Colo. Reg. 7, 848 (Apr. 2025).*

**New Produced Water Usage Standards**

The Rules establish basin-wide targets that each operator must meet by ensuring that, for a given compliance period, a minimum percentage of its total water usage is recycled produced water or an acceptable alternative. *See 2 C.C.R. 404-1-431.* Under the Rules, "Recycled Produced Water" includes any produced water that is reused in oil and gas operations, with or without reconditioning. *See id. at -100.* Further, the reuse of any of the "Recycled Produced Water Alternatives" (Alternatives) enumerated in the Rules' definition will be accounted for like Recycled Produced Water when measuring compliance. *See id.* These Alternatives include brine and other chemical-rich liquids that are commonly disposed of and not returned to the hydrological cycle. *See id.*

*Basin-Wide Usage Measurements*

As noted above, compliance with the Rules is a basin-wide assessment. When determining if an operator has met the minimum percentage required, the Rules focus on that operator's aggregate water usage across all applicable wells within a designated geologic basin (as those geologic basins are identified in the 2002 version of the Colorado Geological Survey's MS-33 Oil and Gas Fields of Colorado). *See 2 CCR 404-1-431(e)(2).* In line with the Consortium's recommendations, these new water usage standards will be phased in and measured over the course of four-year compliance periods starting on January 1, 2026. *See id. at -431(c)(6).* Operators must also account for any permitted wells outside of an established geologic basin; for purposes of compliance, any "non-basin" well must be treated as and allocated toward the basin nearest in proximity to such well location. *See id. at -431(e)(2).*

The Commission's decision to measure compliance with the Rules across each basin (as opposed to a state-wide average, as the Consortium recommended), or on the other hand measuring at a micro level, was an intricate one. Historically, there has been a large disparity in produced water usage across the state due to differences in topography, infrastructure, and localized water scarcities.

*Four-Year Compliance Periods*

In the first four-year compliance period, "an Operator's geologic basin-wide combined oil and gas developments permitted on Oil and Gas Development Plans [OGDPs] filed after January 1, 2026, and the combined subsequent operations to recomplete or restimulate any existing Well within the relevant geologic basin, will use a minimum average of 4% Recycled Produced Water and Recycled Produced Water Alternative for Well Stimulations commenced before January 1, 2030." *2 C.C.R. 404-1-905(c)(6)(A)(i).* During the subsequent four-year period, "an Operator's geologic basin-wide combined oil and gas development, regardless of when the Wells were permitted, will use a minimum average of 10% Recycled Produced Water and Recycled Produced Water Alternative for Well Stimulations commenced before January 1, 2034." *Id. at -905(c)(6)(A)(ii).* The Rules call for the Commission to conduct further rulemakings by June 1, 2028, to set minimum requirements for the periods beginning in 2034 and 2038. If later rulemakings do not occur, then the Consortium's recommended targets will take effect for later compliance periods: minimum averages of 20% for 2034-2037 and 35% for 2038-2041. *See id. at 905(c)(6)(A)(iii).*

An operator must demonstrate compliance with the water usage standards, measured by that operator's proportionate, aggregate usage of Recycled Produced Water (or Alternatives) across all of a relevant geologic basin. *See 2 C.C.R. 404-1-905(c)(6)(B).* Compliance is calculated as follows: (i) the total volume of Recycled Produced Water used, plus the total volume of Alternatives used; (ii) plus qualifying Recycled Produced Water Credits (Credits, discussed further below); (iii) divided by the total volume of all water used for Well Stimulations at all applicable wells within the basin during the relevant four-year compliance period. *See 2 C.C.R. 404-1-431(e)(2)(G).*

Compliance with these standards, including the creation or transfer of any Credits, will be tracked by several new reporting requirements introduced by the Rules.

**Additional Reporting Requirements to Monitor Compliance**

Operators must demonstrate compliance with the new usage targets via new reporting and filing requirements that call for water usage data to be reported monthly, quarterly, and annually, as further explained below.

*Annual Certifications*

While the Rules establish four-year compliance periods as described above, the Rules require annual reporting of relevant water usage figures, to assess whether an operator is on pace to meet the compliance targets. Starting in 2027, each operator must submit an annual certification by April 1 to the ECMC that states whether the operator met the applicable water usage standard for the previous year(s) in the compliance period. *See 2 C.C.R. 404-1-905(c)(6)(D).* Notably, while 100% compliance with the percentage target is required over the four-year compliance period, the operator must only meet 50% of the applicable percentage target for the period during the first year of a given compliance period. *See id.*

For example, during the first four-year compliance period (for 2026-2030), operators must use a minimum average of 4% Recycled Produced Water and Alternatives for well stimulations. In the first Annual Certifications due by April 1, 2027, an operator must demonstrate that it met a 2% usage target for calendar year 2026; for each year thereafter, the operator must demonstrate its average compliance equaled or exceeded the 4% usage target across all wells for the entire four-year compliance period to date.

If an operator does not meet the minimum usage requirement in any Annual Certification, it must file with the Commission a compliance plan that outlines further steps the operator intends to take in order to achieve the minimum usage target by the end of the compliance period. *See 2 C.C.R. 404-1-905(c)(6)(D)(i).*

*Form 47 – Quarterly Water Use Reports*

The Rules also require operators to report water usage on a quarterly basis using Form 47. *See 2.C.C.R. 404-1-431(e).* The content required in Form 47 is driven directly by statutory amendments from H.B. 23-1242. *See C.R.S. § 34-60-134(3).* In these filings, an operator must provide a detailed report of its water usage for each oil and gas location (i.e., for each well pad), including but not limited to: (i) the sources and volume of fresh water used by the operator at the location; (ii) the sources, types, and volumes of all Recycled Produced Water and Alternatives used by the operator at the location; (iii) the methods and amounts of Produced Water and Recycled Produced Water Alternatives disposed of by the operator at the location; and (iv) the total volume of all water used at the location in each month of the preceding quarter. *See id.; 2 C.C.R. 404-1-431(e)(1).* Each Form 47 must also contain similar volumetric data reported on a basin-wide basis and, if applicable, must contain information regarding the creation, transfer, or application of Credits by the operator during the quarter, and during the applicable four-year compliance period. *See 2 C.C.R. 404-1-431(e)(2).*

*Other Reporting Changes*

The Rules also impose several other changes to the ECMC's reporting requirements, including Form 7's report of monthly downhole water usage and disposal or treatment practices for each well. *See 2 C.C.R. 404-1-431(a).* Each operator must also report total fluids and water types used in drilling operations and well stimulation on each Form 5 (Drilling Completion Report) and Form 5A (Completed Interval Report) that the operator files. *See id. at -431(b).*

**Produced Water Credit System Incentives Continued Improvement**

One major highlight of the Rules is the potential to earn tradeable Credits for exceeding the minimum standards in a compliance period. In that event, an operator can claim Credits for the total volume of Recycled Produced Water and/or Alternatives used in excess of what was necessary to meet the minimum threshold for that compliance period. *See 2 C.C.R. 404-1-905(c)(6)(C).* An operator who "creates" a Credit must report the fact on the new Form 47, or on the operator's Annual Certification. *See id. at -905(c)(6)(C)(i).* All water volumes reported under the Rules must be expressed in Barrels; with respect to the credit system, one Credit created or applied is equal to one barrel of water used in excess of or toward satisfaction of the applicable percentage standard for the compliance period. *See id.*

These Credits may be traded to third-party operators in the marketplace, encouraging continued commitment to recycling and reuse by operators that are well above the compliance minimum; provided, however, Credits may be traded and applied only within the same geologic basin and may be held only by approved "Operators" in the state. In other words, there is no avenue for "credit-trading" entities to enter the market. *See 2 C.C.R. 404-1-905(c)(6)(C)(ii).* Any transfer of Credits must be reported to the Commission within ten (10) days of the transfer by filing the new Form 48. *See id.*

The Credit system is intended to bring flexibility to compliance and incentivize continued improvement of recycling practices beyond meeting minimum targets. It does, however, carry certain notable limitations. For example, Credits are subject to expiration—when an operator seeks to utilize Credits that it created, or acquired by trade, to meet its compliance targets, it must apply those Credits within the same four-year compliance period as they were created, or within the first two years of the next compliance period. *See 2 C.C.R. 404-1-905(c)(6)(C)(i).*

**Other Aspects of the Rules**

The Rules formalize several additional requirements for water usage standards, several of which were specifically directed by the statutory amendments of H.B. 23-1242. Examples of these other considerations are outlined below.

*Waste Management Plans*

Any operator required to submit a Form 2A (Oil and Gas Location Assessment) must also submit a detailed waste management plan that outlines "how the Operator will treat, characterize, manage, store, dispose, and transport all types of [E&P Waste] generated" at a well site. Further, each OGDP filed after January 1, 2026, must include a plan that specifies how the operator intends to recycle and reuse produced water as necessary to meet the minimum percentages imposed by the Rules. *See 2 C.C.R. 404-1-905(a)(4).*

*DIC Siting Prohibition*

While the water usage system will necessitate the eventual growth of water treatment facilities and related infrastructure development, the Rules reiterate the broad legislative prohibition against the siting of any new "Centralized E&P Waste Management Facilities" in any area designated as a Disproportionately Impacted Community under existing ECMC regulations. *See 2 C.C.R. 404-1-907(b)(5)*. This includes any facility that "receives for collection, treatment, temporary storage, and/or disposal of Produced Water, drilling fluids, completion fluids, and any other exempt E&P Wastes" generated from oil and gas operations. *See 2 C.C.R. 404-1-100*.

*Air Quality Concerns*

As directed by H.B. 23-1242, the Commission acknowledged in its rulemaking that these new water usage standards would, over time, require infrastructure improvements and operational changes, which themselves could pose additional environmental impacts, namely with respect to air emissions. To address those concerns, the Rules require each operator to submit quarterly reports that detail, in mileage, the operator's reliance on water transport trucks to take fresh and produced water from each well location to and from recycling or disposal sites. *See 2 C.C.R. 404-1-431(f)(1)*. Finally, the Commission has committed to conduct further rulemakings before the end of 2026 that will impose additional requirements on operators to report air emissions associated with their produced water recycling efforts. *See p. 7, Statement of Basis, Specific Statutory Authority, and Purpose, Cause No. 1R, Docket No. 240900229 (available at: [https://ecmc.state.co.us/hearings.html#/rulemaking/producedwater](https://ecmc.state.co.us/hearings.html#/rulemaking/producedwater))*.

### Conclusion

As outlined above, while their enforcement will be phased in over the coming years, the Rules pose a host of new monitoring and reporting burdens on operators in Colorado. Time will tell whether compliance with the Rules will significantly impact the economic viability of new development, at least in certain basins or regions in the state.

## How Junior Associates Should Think About Artificial Intelligence

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### Introduction

It has been almost three years since the "ChatGPT moment" of 2022. Artificial intelligence (AI) is here, integrated into legal research tools, contract review software, and even drafting assistants. For junior associates, this shift isn't just another thing to pay attention to; it is relevant to your daily work and vital to your long-term career prospects.

It is easy to get caught up in the noise of bold headlines predicting that AI will replace lawyers, or vendors promising tools that can turn your job into a few clicks. However, the reality is more balanced. While AI can streamline tasks, it lacks the discernment, nuanced thought process, and doctrinal depth that define effective practice. It is, however, increasingly changing expectations for efficiency, precision, and responsiveness.

Reasonably, some junior associates view AI as a threat. It is critical to understand, though, that the firms investing in these tools are also looking for associates who know how to use them effectively. Your ability to understand, utilize, and manage AI tools will set you apart. The recommendations that follow are intended to help you do that.

### 1. Think of AI As a Tool, <u>Not</u> a Replacement

Think of AI the way you think about Westlaw or Lexis. If you are lucky enough to work for a lawyer who has been practicing for several decades, you have probably heard them recall that these tools replaced "real" legal research. AI is the next step in the same line of evolution: a more dynamic assistant that can digest large volumes of contracts, summarize case law or a markup received from opposing counsel, or even help generate drafts. But ultimately the quality of the work product still depends on you. It depends on your judgment, your legal reasoning, your command of the client's goals, and your ability to understand and utilize AI tools at your disposal. You should not fear AI. But you should fear not knowing how to use it correctly, or at all.

If you have ever used Harvey, Kira, or Casetext CoCounsel, you've already seen what AI can do for your practice. But these platforms are only as good as you are at using them, including your ability to interpret and process their outputs. A junior associate who blindly copies from an AI tool is no more useful than one who doesn't proofread their own work or copies provisions from a precedent contract without reading them. But the associate who can adequately manage the AI, through prompts or a command of the software interface, and refine AI-generated work product into something client-ready? That is an invaluable asset.

### 2. Learn the Task the AI Performs

Just as important as using the right tools is understanding the task those tools are performing. AI can be helpful with just about anything but you can't meaningfully review the output unless you know how to do the work yourself. If you don't understand the legal standard, the structure of a document, or the relevant case law, you won't be able to spot errors, omissions, or subtle misinterpretations in the

AI's output. And because regulatory scrutiny around AI use in legal practice is growing, that kind of oversight isn't optional. Rules regarding the use of AI in legal practice will continue to evolve, and it is not unthinkable that a jurisdiction may implement a ban on the use of certain tools following some unforeseen event. Think of AI as a calculator: useful for speeding things up, but you still need to know how to do arithmetic.

### 3. Understand the Limits (and Risks)

AI is fallible. Judicial decisions reprimanding attorneys for the hallucinations of the AI tools they have used to draft their filings are admittedly entertaining, but they also provide a crucial reminder that these tools are to be used responsibly, and irresponsible use can result in embarrassment, disciplinary action, and ultimately poor results for the client. AI tools can hallucinate cases, misunderstand legal nuance, and give outdated (or entirely false) information. Contract review software with inadequate OCR capabilities will miss things any reviewing attorney would have caught.

AI output is a starting point, not polished work product, and ethical obligations don't disappear just because the technology is new. State Bar Associations still hold attorneys to the same fundamental duties: protect client confidences, avoid incompetence, and ensure that any tools used in your work are properly understood and appropriately applied.

### 4. Use Firm-Approved Tools

Publicly available AI tools often require data-sharing, and uploading client material to those platforms—even just for a "quick summary"—could amount to an unauthorized disclosure.

Your firm likely invests significant time and resources into licensing enterprise-grade AI platforms that are secure, confidential, and integrated into your workflow. That is not just about convenience, it is about risk management. These tools come with safeguards, internal guidance, and sometimes firm-specific training, all designed to keep your work both effective and compliant.

So before you turn to AI, always ensure the tool you are using has been provided by your firm or explicitly approved for the task you are seeking to use it for. You should also ensure that you maintain compliance with any firm policies regarding client approval prior to using AI tools on their matters. Sticking with firm-approved systems isn't just the professional route; it is the safe one.

### 5. Keep Learning

AI is evolving rapidly, and so is its role in the legal profession. Make it a point to follow developments, read your firm's guidance, and experiment (within bounds). If your firm offers training or CLEs on AI tools, attend them. If your practice group hasn't talked about AI yet, bring it up to a senior attorney you trust. Ask thoughtful questions and recognize that the knowledge management professionals sourcing these tools have a deep understanding of them and can rapidly accelerate your ability to use them.

### Final Thoughts

The legal profession isn't being automated away, it is being augmented. As a junior associate, you are in a position to grow up alongside these tools, becoming fluent in a new language that will be second nature to the next generation. You also have the unique advantage of entering the profession at a time where these tools are not ubiquitous, giving you the space to learn not just how to use the tool, but how to perform the task if the tool were ever not available due to regulatory action or technology issues. Embrace AI not as a threat, but as a skillset.

The future winners in the legal industry will undoubtedly have a deep knowledge of the law and how it is applied. But they will also undoubtedly have a deep understanding of how to utilize AI tools to grow, express, and generate value from that knowledge.

Certain portions of this article were initially generated with the assistance of a large language model. In keeping consistent with the article, the output was reviewed carefully and edited heavily.

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# THE ENERGY DISPATCH

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