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INDUSTRY UPDATES

Between a Rock and a Hard Place: Ohio's Seventh District Upholds Perpetual Limestone Lease in *Schubert v. Subtropolis Mining Co.*

Christopher W. Rogers, FBT Gibbons LLP

What happens when a lease for limestone mining is expressly perpetual and disclaims the implied covenant of reasonable development? According to Ohio's Seventh District Court of Appeals in *Schubert v. Subtropolis Mining Co.*, 2026-Ohio-3720 (7th Dist.), you have a valid, enforceable, perpetual lease.

The Lease and the Dispute

The underlying "Option Lease Agreement" was executed on July 23, 2012 between Harold and Susan Conder (as Grantors) and Subtropolis Mining Co. (as Grantee) covering approximately 96.82 acres in Springfield Township, Mahoning County, Ohio. *Schubert*, 2026-Ohio-3720, ¶¶ 34, 49–51. The lease granted Subtropolis the right to mine limestone, and upon the grantee's election to exercise the option, the parties agreed to several critical provisions:

- Under "Mining Rights," the lease provided that the grantee "shall have the right on the subject premises to do all things reasonably necessary to search for, locate, gain access to and to effect the profitable removal of limestone." *Schubert*, 2026-Ohio-3720, ¶ 21.
- The lease also expressly disclaimed any implied obligations: "There shall be no express or implied obligation on Grantee to develop the subject premises at any particular pace or in a particular manner, all such determinations as to the time, pace, manner, and type of development to be at Grantee's sole subjective discretion." *Schubert*, 2026-Ohio-3720, ¶ 22.
- The lease was also expressly perpetual in nature: the "Term" provision stated the grantee "shall hold these leased premises for a term of ten (10) years, from and after the date of execution of this lease agreement; or until all the limestone on or under these leased premises are no longer needed by the Grantee in connection with the mining, extracting and removing of limestone from contiguous properties of these leased premises, whichever term is the longest." *Schubert*, 2026-Ohio-3720, ¶ 24.
- The lease was also integrated: under "Covenants in Writing," the parties agreed: "This agreement is subject to no promise, understanding, condition, agreement or circumstance except such as are expressly written in the foregoing instrument." *Schubert*, 2026-Ohio-3720, ¶ 26.

The appellants—successors in interest who acquired the property via quitclaim deeds in 2020—filed suit in March 2025 seeking quiet title, arguing the lease was an unenforceable perpetual, non-developmental lease void as against public policy. *Schubert*, 2026-Ohio-3720, ¶¶ 2–3, 13. It was undisputed that, more than a decade after execution, no mining operations had ever commenced. *Schubert*, 2026-Ohio-3720, ¶ 7. Subtropolis, for its part, had been faithfully making monthly advance royalty payments—first $97/month, later voluntarily increased to $485—totaling over $32,000 between the original grantors and their successors. *Schubert*, 2026-Ohio-3720, ¶ 4.

Disclaimers of Implied Covenants Work

Affirming the trial court's decision on summary judgment, the Seventh District's analysis turned on two interrelated doctrinal threads: the implied covenant of reasonable development and Ohio's treatment of perpetual leases.

The appellants relied heavily on *Ionno v. Glen-Gery Corp.*, 2 Ohio St.3d 131 (1983), which held that a lease that fails to address the timeliness of development will be subject to an implied duty to operate with reasonable diligence. *Schubert*, 2026-Ohio-3720, ¶ 30. But the Seventh District found *Ionno* inapplicable because unlike the lease in *Ionno*, the Subtropolis lease expressly addressed timeliness by placing all discretion with the lessee, Subtropolis. As such, the scenario the Ohio Supreme Court foretold in *Alford v. Collins-McGregor Operating Co.*, 2018-Ohio-8—

that "parties can prevent application of the implied covenant of reasonable development by including in the lease 'express provisions to the contrary,'" including "a general disclaimer of implied covenants[,]" came to fruition in the Subtropolis lease. *Schubert*, 2026-Ohio-3720, ¶ 31.

The Seventh District also cited *Hupp v. Beck Energy Corp.*, 2014-Ohio-4255 (7th Dist.)—the precursor to the Ohio Supreme Court's decision in *State ex rel. Claugus Family Farm, L.P. v. Seventh Dist. Court of Appeals*, 2016-Ohio-178, which this author also previously covered—for the proposition that "[w]here the lease specifies that no implied covenant shall be read into the agreement, an implied covenant to develop under *Ionno* cannot be imposed." *Schubert*, 2026-Ohio-3720, ¶ 35.

While acknowledging that "[p]erpetual leases are not favored by the law," the court nevertheless had to give effect to the language of the Subtropolis lease before it. *Schubert*, 2026-Ohio-3720, ¶¶ 43–44. Thus, applying the standard articulated in *Hallock v. Kintzler*, 142 Ohio St. 287 (1943) (that a lease will not be construed to create a perpetual right unless the language clearly shows such intent), the Seventh District was compelled to conclude that the parties had intended for a potentially perpetual lease where the end date was 100% determined by the lessee. *Schubert*, 2026-Ohio-3720, ¶¶ 38, 44.

Connecting the Dots: From *Alford* and *Hustack* to *Schubert*

In my 2018 article on *Alford v. Collins-McGregor*, I noted the Ohio Supreme Court's holding that there is no separate implied covenant to explore further, and that the implied covenant of reasonable development does the heavy lifting. *Alford* also confirmed that parties can contract around the implied covenant entirely—either through express lease terms governing development or through a general disclaimer.

And in my 2016 article on the Ohio Supreme Court's decision in *Hustack v. Beck Energy Corp.* (formerly *Hupp v. Beck Energy*), I discussed the Court's unanimous holding that the G&T (83) oil and gas leases were not perpetual no-term leases, in part because those leases contained habendum clauses tying the potentially perpetual secondary term to ongoing commercial production. One of *Hustack's* key holdings was that "an implied covenant to produce in a reasonable period of time does not apply when the lease either provides the specific time in which development must occur (i.e. a primary term) and/or where the lease expressly disclaims implied covenants."

Against this backdrop, then, *Schubert* pushes the principles in *Alford* and *Hustack/Claugus* to their logical conclusion, showing that a lease that disclaims the implied covenant *and* contains no production-based secondary term can endure in perpetuity — even when the lessee has never turned a shovel.

The Takeaway

Schubert provides some reassurance that Ohio courts will enforce well-drafted leases according to their express terms—even leases that, in practice, yield a disfavored, perpetual hold on undeveloped minerals. The combination of an express disclaimer, sole discretion over timing, a right-to-abandon clause (in lieu of a lessor termination right), and ongoing advance royalty payments appears to be a durable structure under current Seventh District jurisprudence. As always, of course, the specific words in the lease matter—a lot—as do the circumstances. For instance, would the outcome have been different if Subtropolis was not making ongoing advanced royalty payments?

The parties have the opportunity to seek a discretionary, jurisdictional appeal with the Ohio Supreme Court, so this case remains open to change and should be monitored.

Considerations for Product Storage Arrangements

David Herrold, McGinnis Lochridge LLP

Terminal operations involving the storage, transportation and blending of crude oil or other product can be a balancing act. The operator must keep the terminal compliant with state and federal safety regulations, air emissions permits, and other regulatory requirements. It must also address customer issues, whether product nominations, blending requests, or disputes concerning operations that could challenge the terminal's capabilities and regulatory compliance. Through all of it, the operator is, of course, always watching its "bottom line" to ensure the enterprise stays profitable, while still acting in a commercially reasonable manner and as a prudent operator under its customer agreements.

This article addresses an operator's storage relationships and agreements, specifically, how an operator can better protect itself and limit risk with product-storing customers.

Terminal Storage Agreements

The storage agreement is the foundational document in a crude oil (or other petroleum product) storage relationship with a terminal. Often called a 'Terminal Services Agreement,' a 'Crude Oil Storage Agreement,' a 'Storage Tank Lease,' or some variation, it is the base document governing a customer's storage of product at the operator's facility. It generally covers storage fees (usually "take or pay" – i.e., the customer pays an agreed rate multiplied by the maximum available barrel storage within the tanks being leased despite the amount of product stored), other fees charged, invoice and payment protocols, contract term and renewals, nomination and delivery protocols, agreed terminal services provided to the customer, product title requirements, force majeure, insurance and taxes, indemnification, and product shrinkage or loss, among other things.

Obviously, each party negotiates for its own interests in arriving at the ultimate agreement. The product storer (usually a 'customer,' 'lessee' or 'tenant') is most interested in facilitating its ability to move crude into and out of the terminal, depending on whether the market is in contango (a reason to store) or backwardation (a reason to sell). The operator is, of course, interested in being paid for its services, whether that be storage, blending, testing, transportation or otherwise—that's the terminal's business and what drives profitability. But other considerations are equally important to the operator, especially protecting it from a customer's delinquency and commercially unreasonable requests and protecting the valuable services the terminal extends to the customer.

A separate set of terminal rules sometimes overlays this base agreement, providing further detail on the rights and duties of the parties at the terminal. If they exist separate from the agreement, they can be incorporated into it as additional terms and conditions, binding the customer to them. They tend to be one-sided (in the operator's favor), usually outlining its ability to operate the terminal in its discretion and to ensure its own commercial reasonableness in responding to customer nominations or other requests.

Protections Against Delinquency

Whether or not the storage agreement or terminal rules say so, terminal operators have strong legal protection against customer delinquency and non-payment: lien rights arising in the operator's favor and covering stored product. These rights come from the 'warehouse lien' provisions of the Uniform Commercial Code (UCC)—a standard set of laws adopted by all states (usually in uniform fashion) applicable to the storage of goods, including petroleum products. If effective as to stored goods, these lien rights plausibly give the warehouse a superior interest in the product stored by the customer at the terminal in the event of delinquency or non-payment, including when a dispute leads to the customer's withholding of payment.

The warehouse lien arises automatically in favor of a 'warehouse' (i.e., the operator) when 'goods' (such as petroleum products) are stored with it by the customer (referred to as the 'bailor') under a storage agreement or 'warehouse receipts' (documents identifying the details of the storage relationship and the product stored). Because the relationship of the operator and storer can be viewed somewhat as an extension of credit (i.e., the operator extending substantial services in return for future payments for such services), the lien secure payment to the warehouse for the stored goods covered by the storage agreement or warehouse receipts, including storage fees, transportation costs, insurance, labor and other charges relating to the stored product. It attaches to product stored at the terminal under the agreement, usually within the tanks the operator has dedicated to customer use, although the storage agreement can extend it to the customer's product more generally.

The lien is possessory only. It extends only to the customer product the operator still possesses. If possession is relinquished, the lien falls off the released product as a matter of law. The lien also attaches only to the product identified in the storage agreement, so if the customer's product departs from its designated tanks and is held elsewhere in the facility (perhaps in other customer tanks that have been emptied), the lien likely ceases to attach to it. However, where a storage agreement provides for the lien to attach with respect to charges "in relation to other goods," the lien broadens in scope to those other goods.

A lien against stored product is an important feather in the operator's cap. But it does not automatically get the operator paid for the extent of a customer's default (over and above any letter of credit that may be posted). To convert product collateral to cash and satisfy unpaid debt owed under the storage agreement, the UCC requires the operator to foreclose its warehouse lien against that collateral by public or private sale. A customer that regularly deals in petroleum product is likely to be held out as a 'merchant' in such product, meaning the operator can use the substantially easier private sale mechanism under the UCC to foreclose its lien. It can also opt to sell the product publicly, a much more cumbersome undertaking.

For a private sale of stored product, the operator must notify its customer (and any other person with an interest in the product) of the sale, including the amount owed and the sale terms. Although the customer may not appreciate the sale of its product to satisfy unpaid sums owing to the terminal, it has the right to 'redeem' the product by paying the warehouse lien value and any expenses the operator has incurred in the proposed sale. If redemption does not occur and a sales notice is given, the operator may apply the proceeds to its lien, paying any resulting surplus over to the customer.

An operator whose customer is a product 'merchant' may sell publicly if it chooses; it *must* do so if the customer is not a 'merchant.' The public sales process is more cumbersome, requiring the operator to set a time and place for the sale and a date by which the customer may redeem its product, along with notice of that timeline to the customer and any interested parties. It also obligates the operator to comply with a host of additional requirements, including a sale by auction with pre-published advertisements that again state the customer's redemption deadline. As with a private sale, the operator may then apply sales proceeds to its lien, paying any surplus over to the customer.

Storage Agreement Suggestions

For a terminal operator, five areas deserve attention in negotiating a storage agreement with customers: [i] strong damages limitations language; [ii] broadened lien language; [iii] reasonable governing law and convenient forum requirements; [iv] broad operator discretion; and [v] product quality exceptions.

First, **damages limitations**. While the agreement should not (and likely cannot) negate all damages, a damages limitations clause should be used in the storage agreement or terminal rules. Such a clause limits the amount and types of damages a customer can seek (applied reciprocally to the operator), stripping out consequential and incidental damages, lost profits, prejudgment interest, expectation damages, punitive or exemplary damages, loss in value of the product stored, and the like. The operator can also attempt to impose caps on actual damages—for example, at the aggregate storage charges the customer has paid over a certain period (inception-to-date, year-to-date, etc.). A jury trial waiver is likewise a significant benefit, goes hand in hand with damages limitations, and should be spelled out in the storage agreement. These limitations help the operator better foresee and control the overall risk of its relationship with the storage customer.

Second, **broad lien rights**. A storage agreement need not specify the operator's UCC lien rights for them to arise—they arise 'by operation of law'—but it remains prudent to include them in the storage agreement or the terminal's rules to place the customer on direct notice. The lien rights should apply to the product stored in assigned tanks and also 'in relation to all other goods or product' of the customer, wherever located within the terminal. This gives the operator both the specific and the general liens the UCC affords, and lets it reach customer product held within the terminal but outside the assigned tanks to satisfy unpaid charges and fees. The notice of warehouse lien rights should be conspicuous within the agreement or rules; where possible, the agreement should also define the customer as a 'merchant'—one familiar with and regularly dealing in the types of goods (i.e., product) stored at the terminal. Finally, such clauses should recite that the customer exclusively owns the stored product and that, to the extent others have interests in it (such as lenders or other secured parties), they authorized the product to be in the customer's possession before storage for purposes of storing it with the terminal, or of transporting or selling it, and for the customer to pledge it to the operator for payment due under the agreement in order to procure a warehouse receipt. Terms like these advance the operator's lien claims if issues arise with a delinquent or non-compliant customer.

Third, **governing law and forum**. Parties often negotiate governing law and forum-selection clauses with an eye toward their own states of incorporation or headquarters, or land on a situs that bears no real relation to their relationship. If the relationship later becomes the subject of litigation, the parties may be forced to litigate in unfamiliar territory under unfamiliar law—though as to lien rights, the UCC's uniform nature is a straightforward benefit to lien rights and foreclosure, generally. Serious consideration should be given to choosing the law and forum of the state where the terminal operates and the product is stored, though other business factors certainly call for a different jurisdiction to apply.

Fourth, **broad discretion**. A storage agreement cannot be so one-sided as to relieve an operator of its 'commercial reasonableness'—the obligation to act as a prudent operator with respect to a customer's stored product. The agreement or the terminal's rules can, however, define the extent of the operator's obligations and better delineate what acts are specifically permitted and, thus, commercially reasonable if the operator undertakes them. For instance, the storage agreement should directly address the operator's discretion to accept or reject nominations, or partial nominations, delivered by its customers. That relieves the operator of having to perform every nomination exactly as the customer outlined it. The agreement should also address the operator's discretion to acknowledge or accept title transfers—transfers of product ownership while the product sits *in situ* at the terminal—which, left unchecked, can work to the operator's disadvantage with respect to its lien rights. Requiring a formal title transfer process and, ultimately, the operator's approval enables the operator to better retain its lien and secured interest in the product sought to be conveyed. Other duties under the storage agreement or terminal rules may be described as discretionary as well, provided the discretion is not so one-sided as to render the customer's rights illusory.

Finally, **product quality**. An operator's duties certainly include an obligation to preserve the product the customer delivers. However, as any operator knows, contamination—whether by water, sulfur or differing grades of product passing through common piping at the facility—can diminish the overall quality of a customer's crude delivered to and stored in its leased tanks. A storage agreement should, therefore, address the operator's exculpation from liability for product quality variation or degradation, reciting the customer's acknowledgment (and acceptance) of conditions that could diminish the quality of its delivered and stored product. Such a clause may effectively reduce the customer's available remedies from the world of tort to a simpler (and more ascertainable) claim for breach of contract, which the operator would then be better able to defend and for which damages claims are somewhat more limited.

Conclusion

Terminal operations can impose significant burdens on an operator. Carefully crafted clauses—ones that protect the operator, more precisely define its obligations and its commercial reasonableness, and strip the customer of potential claims, remedies, and damages—give the operator more certainty in the operator/customer relationship and limit its risk.

Pennsylvania House Bill 2880 Would Create Statewide Siting Standards for Solar, Wind, and Battery Storage Projects

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On October 21, 2026, House Bill (HB) 2880 was introduced in the Pennsylvania House of Representatives to amend the Pennsylvania Municipalities Planning Code (MPC) and establish statewide siting standards for utility-scale solar, wind, and battery energy storage projects. If enacted, the bill would significantly limit local authority over these projects and give developers new tools to challenge restrictive ordinances. Key points for developers, landowners, and municipalities follow.

Statewide Standards Would Cap Municipal Authority

Municipalities would have to permit qualifying renewable energy facilities in agricultural and industrial zoning districts by right, special exception, or conditional use, and they could not adopt permitting or zoning requirements more restrictive than the bill's standards. Municipalities would have six months to make existing ordinances conform; after that, inconsistent provisions would be unenforceable.

The bill would cover solar and wind facilities with at least 20 megawatts of nameplate capacity, energy storage facilities with at least five megawatts of output deliverable for at least four hours, and combined generation-and-storage facilities of at least 20 megawatts. Rather than uniform rules, it sets maximum setback, height, and noise standards—for example, 50- and 150-foot setbacks for solar and storage, a 25-foot solar panel height limit, and a 47-decibel noise limit near homes, schools, and similar sites—and requires decommissioning plans for solar and storage projects. Municipal fees would be capped at the lesser of $1,000 per megawatt or $100,000—with reimbursement of reasonable processing expenses above $100,000—and municipalities could not impose a construction deadline shorter than five years.

New Enforcement Tools Against Restrictive Ordinances

The bill would prohibit "unauthorized local ordinances"—those that prohibit or unreasonably delay, impede, or prevent renewable energy facilities—unless necessary to protect public health, safety, or welfare. An aggrieved person could sue a municipality directly in Commonwealth Court to invalidate or enjoin such an ordinance, or ask the attorney general to review the ordinance and consider bringing suit. Courts could award attorney's fees and costs against a municipality that acted with negligent disregard of state law limits and against plaintiffs whose claims are frivolous or lack substantial justification.

These remedies would apply to existing ordinances as well as new ones and could reshape how renewable energy siting disputes are litigated in Pennsylvania.

New Obligations for Developers

Before applying, developers would have to consult in good faith with each host municipality's governing body on site selection, alternative locations, viewshed and environmental impacts, mitigation, and community benefits, and they would have to provide technical reports addressing project need and cumulative environmental impacts. Developers would also have to enter into legally binding community benefit agreements requiring a payment upon commencement of operation of $1,000 per megawatt of nameplate capacity, prorated among host municipalities. If a municipality refuses to enter into an agreement after good-faith negotiations, the developer would contract with local community-based organizations instead.

Outlook

HB 2880 has been referred to the House Consumer Protection, Technology and Utilities Committee. With little time remaining in the 2025-2026 session, enactment this session appears unlikely. Even so, the bill offers a potential framework for future legislation addressing the balance between local control and statewide energy infrastructure needs.

Developers, landowners, and municipalities should monitor HB 2880 and consider how its standards could affect pending and planned projects.

Read the legislation: Pennsylvania House Bill 2880.

Financing for Enhanced Geothermal Systems: Developing Project Finance Today, Further Possibilities in the Future

Michael Cooper, Finance Counsel, Fervo Energy

Cape Station's March 2026 project financing, a $421 million non-recourse facility arranged by a syndicate of nine international banks, was the first construction-stage project financing of its kind for an enhanced geothermal systems ("EGS") project. The facility combined a construction-to-term loan, a tax-credit bridge, and a letter-of-credit facility, underwritten against contracted offtake with Southern California Edison and Shell Energy North America. The transaction matters less as a single data point than as proof that EGS can be financed with the tools of conventional project finance, at a moment when the market is demanding firm, carbon-free generation that can be built faster than nuclear and can run when wind and solar cannot. This piece examines what makes that financing structure different from conventional power project finance, where the market is likely headed as developers move from a single flagship project to a portfolio of them, and the legal and structural case for a geothermal-specific analog to oil and gas reserve-based lending.

I. What Makes Project Finance for EGS Different?

Resource risk is familiar to power project lenders: wind and solar financings depend on assessments of how much energy a project can reliably produce. Conventional geothermal has also attracted project financing, but proving a hydrothermal resource, beyond being a geographic rarity, has historically required substantial drilling investment before lenders had enough evidence to underwrite output. EGS changes that premise. Drilling, stimulation, and completion design can now create the permeability needed for commercial production in rock that would never have hosted a conventional hydrothermal reservoir, and EGS developers deserve real credit for solving much of that problem on the engineering side, turning geothermal development into something closer to a repeatable manufacturing process than a search for a geographic rarity. What EGS project finance still has to work out, in a way conventional power project finance never has to, is how to value that engineered resource: how much heat and flow it will produce, for how long, and with what confidence. That valuation question, more than the underlying engineering, is the real dividing line between financing an EGS project and financing a wind or solar asset, and the market, and the legal documents that memorialize its judgments, are still feeling their way toward an answer.

Cape Station's structure shows one way that additional risk can be bounded rather than eliminated, without purporting to be the only way. Debt sizing there ran off an independently prepared, probabilistic production forecast, backed by a debt service coverage ratio test and a dedicated drilling-and-maintenance reserve, with the forecast refreshed against field-measured flow, temperature, and pressure data. Critically, the collateral package preserved the developer's ability to work over, deepen, or add wells, so that underperformance could become an economic decision about incremental drilling capital, closer to the decision an oil and gas operator makes when a well declines faster than forecast, than a binary, existential risk to the project. That structure is a credible template, and other financings are likely to test variations on it as the asset class matures.

That mechanism only works because the underlying performance data is becoming repeatable, and increasingly, that is not just a Fervo story. Fervo has reported cutting drilling time from 70 days for its first horizontal well at Project Red to 21 days for its fastest Cape Station well to date, while reducing per-well drilling costs across its first four Cape horizontal wells from $9.4 million to $4.8 million. Mazama Energy reported in September 2026 that its second well at Oregon's Newberry Crater site reached 10,350 feet in fifteen drilling days, an 80% improvement over its prior well there. Ormat Technologies has invested in Sage Geosystems and is advancing a two-well Sage pilot at an existing Ormat power plant in Nevada, with drilling preparations underway. Given the pace of activity across the sector, other operators are likely to report similar drilling milestones before long. Improved drilling and measurement data of this kind is what lets an independent engineer build a probabilistic forecast instead of a speculative one, and it is a precondition for the portfolio and resource-based lending structures discussed in Parts II and III: neither is possible without a performance record that more than one company, and eventually a third-party engineer, can underwrite.

II. Portfolio Financing Across Projects and Areas of Interest

Cape Station's financing is a single-project structure. As developers move from one flagship project to a pipeline of them, and to broader areas of interest ("AOIs") with confirmed heat resource but not yet a fully permitted, contracted project, the market will need more than single-project construction-to-term debt to keep up. The scale of that shift is already visible at Fervo: the company reported a contracted backlog of 658 megawatts under binding power purchase agreements as of its second quarter 2026 results, and a subsequent 396-megawatt agreement with Google brought total executed offtake to just over 1 gigawatt, against a development pipeline the company has reported at more than 50 gigawatts spanning multiple projects and AOIs. A pipeline of that scale, spanning multiple phases and counterparties, starts to outrun what a single construction loan is built to finance.

Two developments are worth watching. The first is financing structured at the portfolio level rather than the project level, sized to a company's pipeline rather than to any one asset. As more projects move through drilling, crossflow testing, and construction at the same time, a portfolio facility could expand to fund that activity and contract as individual projects graduate into standalone financing, diversifying resource risk across assets in a way a single-project loan cannot. Within that kind of facility, different assets would likely draw different levels of credit depending on their stage of development, with an early-stage AOI supported by limited subsurface data drawing far less credit than a project that has completed crossflow testing and is ready for construction, so that the facility's overall exposure tracks the actual risk profile of the portfolio rather than treating every asset alike. Agreed repayment and collateral release mechanics would allow projects to enter standalone financing without impairing the remaining portfolio.

Alternatively, the facility could convert from development financing into construction and term debt as specified milestones are achieved.

The second, and more speculative, development is the question of what credit, if any, a lender should extend against confirmed heat in place within an AOI, before a project reaches the stage Cape Station did. Mining finance has long distinguished measured and indicated resources from proven reserves for disclosure and lending purposes, and will sometimes extend limited credit against the former at low advance rates. For an emerging classification framework could support a graduated approach, but lenders have yet to establish broadly accepted conventions for translating resource assessments into borrowing capacity. Whether an analogous, heavily discounted credit product could develop for confirmed-but-undeveloped geothermal resource, tied to independently verified subsurface data rather than a producing well, is an open question, and not an easy one. But it is exactly the kind of question worth asking now, given the pace of demand for firm, clean, baseload electricity. EGS has moved faster over the past few years than almost anyone in the industry expected, and investors, lenders, and governments each have a role to play in being creative about directing capital toward developing the technology and the industry further, rather than waiting for every convention to be settled before acting.

III. The Case for Geothermal Resource-Based Lending

An emerging corollary to these portfolio structures is geothermal resource-based lending, adapting the borrowing-base discipline of oil and gas finance to geothermal assets. In the oil and gas practice, lenders establish and periodically redetermine a borrowing base using engineering assessments of proved reserves, projected net revenues, and assumptions about prices, production, and development costs. A geothermal facility could initially be anchored by producing assets, with more limited credit for development assets supported by independently verified resource assessments and an approved development plan. Eligibility criteria, advance rates, concentration limits, and periodic redeterminations would govern how borrowing capacity grows as additional resources move toward commercial production, rather than assigning lending value to heat in place alone. An approved development plan would connect funding to defined milestones, budgets, and completion schedules, giving lenders a basis for monitoring progress and adjusting availability as development risks change.

The central challenge is connecting an independently assessed resource to a credible route to revenue. Unlike a barrel of oil in the ground, heat in the ground is not sold to anyone: the power purchase agreement monetizes electricity, not heat, so a lender today must look through the drilling, plant, and offtake together to reach cash flow. Oil and gas still offers a useful analogy: gas without access to a pipeline may have substantial resource potential but limited immediate borrowing value. Geothermal similarly requires a path through drilling, surface facilities, interconnection, and offtake before it can support debt repayment. A borrowing base would need to account for the cost, timing, and risk of completing that path.

Separating the subsurface and generation businesses into distinct legal entities, linked by a heat or steam supply agreement, could help define the resource lender's collateral and revenue rights. That separation would not itself eliminate dependence on the power plant or its revenues. Lenders would still need to assess the purchaser's creditworthiness, completion risk, and arrangements preserving operations and payments following default. Resource valuation alone will not establish bankability: lenders also need an enforceable collateral package and a workable means of preserving or transferring the business following default.

For projects on federal lands, diligence must address applicable consent and qualification requirements affecting lease transfers and lender remedies. Where assets already support project debt, existing liens, negative pledges, and restrictions on shared infrastructure may constrain a new resource facility. Initially, unencumbered assets may offer a simpler starting point. New structures may give rise to intercreditor arrangements to allocate priority, control over remedies, and access to infrastructure between resource and project lenders, while avoiding conflicting claims on the same revenues. The relevant structuring questions therefore extend beyond corporate separation to the practical ability to operate, complete, or transfer a project when its original financing plan fails.

An important foundation is now taking shape. The Society of Petroleum Engineers, Project InnerSpace, and varied interested stakeholders are developing the Geothermal Resources Management System ("GRMS") as a geothermal corollary to the Petroleum Resources Management System that is the foundation for reserve-based lending. The next challenge is translating that classification framework into lending conventions: what evidence supports inclusion

in a borrowing base, how much credit different development stages receive, and how independently verified performance informs periodic redeterminations. Lenders will also need agreed forecasting assumptions for output and thermal decline, reporting requirements, and remedies when a redetermination reduces borrowing capacity below outstanding debt.

None of that makes the idea premature so much as it defines the agenda. If geothermal converges on shared classification, forecasting, and lending conventions, a geothermal resource-based lending market is a plausible next step: more predictable access to capital and borrowing capacity that grows as resources are demonstrated and projects mature, rather than a fresh, bespoke negotiation for every project. Getting there starts with naming the destination: lenders and developers agreeing on a bankable initial structure, government (specifically the BLM) buying in to support geothermal development on federal lands, and the industry then iterating on that structure.

Conclusion

Cape Station answered the threshold question of whether a single EGS project can be financed with the tools of conventional project finance. The harder, and more interesting, question is whether the market, and the contracts, collateral packages, and corporate structures that lenders and developers negotiate, can standardize enough to finance many projects at once, across a pipeline rather than one deal at a time. That standardization is as much a legal exercise as a financial one: it depends on classification conventions, model contract terms, and corporate structures that do not yet exist in geothermal in the form they do in oil and gas or wind. Energy lawyers who help build those conventions now, while the asset class is still young enough to shape, will have written the playbook the rest of the industry uses to scale.

Stop Letting Energy Data Control Your Legal Strategy

Don Mangum, Epiq

Energy companies face unprecedented legal, regulatory, and reputational risks. For many, data is the Achilles heel that, left unaddressed, invites catastrophe.

In an industry shaped by decades of acquisitions, legacy systems, and evolving environmental regulations, legal teams confront a simple but costly reality: if you don't control your data early, it will control your case later.

This is where matters go off track, and where the right legal technology strategy separates leaders from everyone else.

Energy Data Poses a Unique Challenge

In the face of rising risk, energy companies must take strategic steps to maintain compliance. Energy organizations carry history in every sense of the word. Their data estates are older, larger, and less uniform than those of most other industries. Mergers introduce incompatible systems. Regulatory requirements from national, state, provincial, and local bodies are changing frequently.

Older data estates also mean a higher volume of critical, scanned paper files. And paper-heavy datasets present a whole other challenge to process. Traditional optical character recognition (OCR) struggles with these aging formats that produce inconsistent quality and handwritten notes. Review slows, costs rise, and insights are missed.

AI OCR rewrites this equation. Legacy documents become usable data quickly and accurately. Legal teams revisit older datasets without prohibitive effort and extract value that was previously locked away.

However, while technology does open doors, it won't solve your data problems on its own.

Early Case Assessment Facilitates Planning That Controls Costs

Large datasets create opportunities for insight, but delaying action quickly turns them into a cost driver.

When custodians aren't identified early, when scope isn't defined, when early case assessment (ECA) is skipped, everything becomes reactive. Teams panic, and data volumes balloon. Law firms lose trust in the process and default

to running broad search terms across datasets "just in case."

This approach quietly increases risk. Unfocused searches increase noise, slow review, and drive unnecessary cost. Worse, they create a false sense of completeness while burying critical documents.

Early Case Assessment breaks that cycle. By identifying key custodians and evaluating likely issues early in a matter, legal teams narrow scope before data volumes spiral. Effective ECA provides the foundation for defensible culling strategies and better-informed decisions throughout the matter.

This is where expert support becomes essential. Providers that understand energy data guide culling strategies that reflect industry-specific realities, whether that's environmental compliance records or operational communications.

When paired with summarization and conversational analysis tools, legal teams quickly surface key themes, identify patterns, and prioritize high-value documents.

Using AI Wisely Creates Efficiencies

The appropriate use of AI in legal workflows is nuanced. Applying AI review properly with a small review team to quality-check the results makes AI tools more efficient and cost-effective.

Advanced analytics and summarization tools identify connections and anomalies that manual review misses. They surface "smoking gun" documents earlier in the process. This enables teams to revisit assumptions without starting over.

The cost structure of your AI tool becomes critical here. Tools that charge per prompt discourage exploration. Teams become conservative with questions right when they should be probing deeper.

The right model is flexible and will remove that barrier. Legal teams must be able to iterate on, refine, and investigate datasets without incurring additional fees.

Know Your Data, Control Your Outcome

There is one overlooked advantage in eDiscovery that happens to also be the simplest: knowing your dataset. You can't plan around what you don't understand.

From source systems to document types, understanding your data creates a competitive advantage. Scope matters faster, avoid overcollection, and respond to regulatory pressures with confidence.

That matters particularly in the energy sector. Internal teams routinely ask, "What data is most relevant to this issue?" and "Who knew what, and when?"

Those aren't questions you answer with guesswork.

The More Your Provider Knows, the Faster You Move

Long-term strategic partnerships foster the institutional knowledge, trust, and process understanding required to maintain efficiency when you need it most.

Switching providers might feel like flexibility, but it creates fragmentation. Every new provider must relearn your workflows, reinterpret your data, and rebuild context from scratch.

Familiarity pays off in three distinct ways:

1. Faster case ramp-up because context already exists
2. Consistent, accurate, and efficient data handling across workflows
3. Strategic guidance based on extensive institutional knowledge

The Optimal Framework for Energy Legal Teams

The right path forward for energy companies is anything but incremental.

The most successful teams are taking a holistic, flexible, and adaptive approach. They plan early, define scope with precision, and reduce their datasets before review, long before sprawling email archives, legacy systems, and decades of acquired data drive costs. They factor in the realities unique to the industry: aging paper records, complex environmental matters, and evolving oversight from regulators.

As AI works in tandem with human reviewers, critical insights across massive, heterogeneous datasets become visible. These are also the teams that commit to long-term partners who know their data estate inside and out.

Continuing to treat data as a volume problem will only lead to overspending and underperformance. Energy legal teams that take a strategic approach to data control achieve faster investigations, lower costs, and respond to regulatory requests with confidence.

The Legal Framework for Produced Water: Ownership, Rights, and Regulations (Part 2)

Bobby Majumder, Ian Strang, Edward J. Grattan II, FBT Gibbons LLP

This article is Part 2 of a 3 Part series from FBT Gibbons. Part 1 was featured in the July 2026 issue of the ELA.

As discussed in part one of this series, produced water has become increasingly important in discussions surrounding water scarcity, energy production, and long-term resource management across the Southwest.

As interest in recycling and reuse grows, legal questions have moved to the forefront. Before produced water can be treated, transferred, commercialized, or reused at scale, stakeholders must first determine who owns it and who regulates it.

The answers are not always straightforward.

Ownership and Rights

Legal ownership of produced water has emerged as one of the most closely watched issues in the Southwest, particularly in Texas, where commercial interest in recycling, beneficial reuse, and mineral recovery has grown rapidly.

Historically, produced water disposal was primarily an operational and regulatory issue. Operators needed to manage, transport, and dispose of produced water, often through underground injection. As treatment technologies improved and freshwater scarcity intensified, however, the possibility of utilizing produced water raised a new question: who actually owns it?

In 2025, the Texas Supreme Court addressed that issue in *Cactus Water Services, LLC v. COG Operating, LLC*. The texas supreme court held that, absent contrary contractual language, produced water belongs to the mineral lessee rather than the surface estate because it is a byproduct of hydrocarbon production managed within the oil-and-gas regulatory system.

The holding in *Cactus Water Services* matters beyond abstract property doctrine. It gives operators stronger legal footing to contract for recycling, transportation, treatment, and potentially downstream commercialization of produced water.

The ruling also reinforces the idea that produced water, while water-based, is not simply "water" in the ordinary groundwater sense, but a distinct byproduct associated with the mineral estate and regulated through the oil-and-gas framework administered by the Railroad Commission of Texas and the Texas Commission on Environmental Quality (TCEQ).

Important questions nevertheless remain unresolved. Uncertainty continues regarding how contracts may allocate value from treated water, how extracted byproducts such as lithium should be characterized, and whether future

disputes may arise over royalties, avoided disposal costs, or profits associated with reuse.

Outside Texas, the legal landscape remains fragmented. Produced water ownership and regulatory structures vary by state, and the broader U.S. framework remains inconsistent. That fragmentation complicates regional development because cross-border infrastructure and investment decisions often depend on predictable legal rights.

Legal and Regulatory Pathways and Challenges

Produced water governance is divided across federal and state authorities, and that fragmentation is especially important in the Southwest.

At the federal level, the Bureau of Land Management's 2026 Instruction Memorandum encourages reuse and recycling of produced water from oil and gas production on public lands and directs field offices to identify beneficial reuse opportunities while remaining consistent with existing state and federal requirements.

The policy is notable because it reflects federal support for moving beyond disposal where reuse may help conserve freshwater resources.

Federal environmental law also remains important. In 2025, the Environmental Protection Agency announced its intention to revise produced-water discharge regulations to provide greater flexibility, including possible expansion of where treated oilfield byproducts may be discharged.

That potential shift underscores the degree to which regulatory policy—not just technology—will shape the future of produced water reuse.

In Texas, the regulatory structure is divided principally between the Railroad Commission of Texas, which regulates oil and gas operations and much oilfield water handling, and the TCEQ, which oversees broader environmental permitting and surface-water regulation.

That split structure can complicate beneficial reuse pathways because different intended uses trigger different regulators, permits, and evidentiary requirements.

Texas has gradually moved beyond pilot-stage experimentation toward a more formalized reuse framework. While the Railroad Commission initially established pilot programs to evaluate treatment effectiveness and limit early-stage risk, more recent legislative and regulatory developments signal a broader policy shift.

Those developments include liability protections for reuse activities and the TCEQ's ongoing development of permitting and water-quality standards. Texas remains cautious with respect to large-scale, non-oilfield applications, but the state is increasingly positioning produced water as a viable supplemental water source rather than a purely experimental concept.

Texas also finalized significant oilfield waste-rule changes in 2025, implementing the first major overhaul of its commercial oilfield waste disposal and recycling framework in decades and modernizing requirements applicable to produced-water handling and reuse.

At the same time, standards governing discharge of treated produced water into rivers and creeks remain unsettled. Regulators have begun evaluating—and in some cases issuing—permits for surface-water discharges in regions such as the Permian Basin and Eagle Ford. Questions nevertheless remain regarding water-quality standards, monitoring requirements, and long-term environmental impacts.

New Mexico has taken a more cautious approach. In 2025, the state adopted rules prohibiting discharge of treated produced water from oil and gas extraction to both ground and surface waters.

That prohibition reflects ongoing concern surrounding unresolved scientific and treatment uncertainties. Although the rules remain subject to future reconsideration and ongoing rulemaking proceedings, the divergence between neighboring Southwest states illustrates how fragmented regional policy may complicate broader commercialization efforts.

Key Takeaway

The legal framework governing produced water continues to evolve rapidly. Ownership disputes, regulatory standards, environmental concerns, and commercialization efforts are all shaping the future of produced water reuse across the Southwest.

Texas has emerged as the leading testing ground because of its production volumes, infrastructure, legal developments, and increasingly active regulatory environment. But many questions remain unsettled.

MEMBER NEWS

A MESSAGE FROM IEL

The Institute for Energy Law will present the **IEL Distinguished Leadership in Energy Award** to **Toby Z. Rice** on February 18, 2027, during the Leadership Award Reception and Dinner at the 78th Annual Energy Law Conference. This award is presented annually to a person associate with the energy industry in recognition of extraordinary professional and civic achievement.

The 78th Annual Energy Law Conference will also feature the IEL Legends Award presentation *(recipients to be announced)*, followed by the presentation of the Deans of Oil and Gas Practice Award to **Patrick S. Ottinger** on February 19, 2027.

UPCOMING IEL PROGRAMS

Registration is open for the 15th ITA-IEL-ICC Joint Conference on International Energy Arbitration, January 28-29, 2027 at The Four Seasons Hotel Houston; and IEL's 78th Annual Energy Law Conference, February 18-19, 2027 at The Westin Houston, Memorial City. IEL Advisory Board Members receive complimentary registration to IEL's Annual Conference – AB Members will receive a personalized email with a special registration link later this month. Mark your calendar for the 10th National Young Energy Professionals Conference, March 30-31, 2027 at The Westin New Orleans. Check out our Programs Calendar for registration and more information about upcoming events.

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We are honored and excited to add the following companies and individuals to IEL's membership roster. Please join us in welcoming them to our organization!

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