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Five Ratemaking Takeaways From FERC's Panhandle Eastern Pipe Line Company, LP Order

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On December 16, 2022, the Federal Energy Regulatory Commission ("FERC") issued Panhandle Eastern Pipe Line Company, LP, its first opinion and order on an initial decision in a Natural Gas Act ("NGA") Section 4 general rate case proceeding in nearly ten years. The last NGA Section 4 general rate case to be fully litigated was *El Paso Natural Gas Co.*, a 2013 decision that derived rates based on a test period that straddled 2010 and 2011. *El Paso Nat. Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at P 73 (2013) (El Paso), *order on reh'g*, Opinion No. 528-A, 154 FERC ¶ 61,120 (2016), *order on compliance & reh'g*, Opinion No. 528-B, 163 FERC ¶ 61,079 (2018). The changes experienced by the natural gas industry since that time are immense. For example, *El Paso* predated market changes spurred by hydraulic fracturing that accelerated the replacement of coal with natural gas for base generation, the export of liquefied natural gas ("LNG"), and the general debate over the future dependence upon and use of natural gas from proposed municipal gas bans to the blending of hydrogen into a gas stream to reduce its carbon footprint.

Yet, despite these monumental shifts in the natural gas marketplace, *Panhandle* often reads like an old school rate case decision, with principles expounded upon that would be familiar to any rate case lawyer practicing before FERC over the past two decades. While much of the decision is straight and narrow, a number of key themes and takeaways can be found in the text. Here are five of them:

1. **The new "last litigated ROE" is 11.25%.**

It is an axiom of regulatory law that a regulated monopoly, such as an interstate natural gas pipeline company, is permitted the opportunity to earn a reasonable return on its investments. The just and reasonable return on equity ("ROE") is one of the most litigated components of any rate case because ROE can be one of the largest drivers of a rate increase or decrease. In *Panhandle*, FERC set the pipeline's ROE at 11.25%. This is the median return generated when FERC averaged the results it obtained from a Discounted Cash Flow analysis and a Capital Asset Pricing Model analysis using a five-member proxy group.

FERC policy often uses the "last litigated ROE" as a proxy for just and reasonable rates when it is developing initial rates for existing facilities being acquired by a new pipeline. It has also relied upon the "last litigated ROE" in rulemaking proceedings that concerned pipeline rates. Prior to *Panhandle*, the last litigated ROE was the *El Paso* decision's 10.55%. Hence, *Panhandle* marks an increase of 70 basis points and may change the calculation made by pipelines and shippers when they consider whether to litigate a rate case proceeding or agree to a black box settlement without a stated ROE.

2. **There continues to be ratemaking uncertainty spurred by *United Airlines v. FERC*.**

In 2018, FERC revised its ratemaking policy to prohibit pipelines organized as pass-through entities for income tax purposes, such as master limited partnerships (MLP), from collecting an income tax allowance ("ITA") in their rates. *Inquiry Regarding the Comm'n's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Revised Policy Statement), *order on reh'g*, Revised Policy Statement Rehearing Order, 164 FERC ¶ 61,030 (2018). The 2018 policy also considered the treatment of accumulated deferred income tax ("ADIT"). Prior to the 2018 policy change, MLP pipelines had recorded ADIT to compensate them for the tax timing difference between the accelerated depreciation permitted by the Internal Revenue Service and the straight line depreciation required by FERC ratemaking. ADIT served as a debit to rate base, so a higher ADIT lowered rate base, resulting in lower rates, while a lower ADIT resulted in a higher rate base, with ADIT resetting to zero whenever there was a taxable event, such as a sale or restructuring, consistent with tax normalization rules. The 2018 policy held that MLP pipelines could retain their ADIT balances when their ability to collect an ITA was abolished, as opposed to refunding amounts to pipeline shippers, because doing so would result in unlawful retroactive ratemaking. This policy on MLP rates followed *United Airlines v. FERC*, a 2016 D.C.

Circuit decision holding that FERC acted arbitrarily and capriciously for permitting such a recovery because it had not explained why this would not result in a double-recovery of income tax costs in rates, both from the ITA and from the return on investment. *United Airlines, Inc. v. FERC*, 827 F.3d 122 (D.C. Cir. 2016). In 2020, the D.C. Circuit issued *SFPP, L.P. v. FERC*, which affirmed the 2018 policy change as consistent with *United Airlines*. *SFPP, L.P. v. FERC*, 967 F.3d 788 (D.C. Cir. 2020).

The *Panhandle* pipeline reorganized as an MLP in 2018, prior to the policy change, making *Panhandle* the first fully litigated NGA Section 4 general rate case to grapple with the precedent initiated with the *United Airlines* decision. It considered the treatment of ADIT and excess ADIT ("EDIT"), both in rate base and the equity component of capital structure. FERC followed its precedent that permitted the removal of ADIT from rate base, but held that the maintenance of a rate base account for EDIT as a regulatory liability, and the amortization of EDIT back to ratepayers, did not violate the rule against retroactive ratemaking. It then held that this rate base treatment for ADIT and EDIT then necessitated the removal of ADIT from the equity component of capital structure, as well as the removal of EDIT from retained earnings used to determine the equity component of capital structure. The practical result of this finding was to thin the equity component in capital structure used to calculate the pipeline's rates. In a partial dissent, Commissioner Danly encouraged rehearing on whether *SFPP* required this result.

3. Arguments about the future of natural gas use may be unavailing for ratemaking purposes.

In *Panhandle*, FERC set depreciation rates based upon a 35-year economic life. FERC held that it did not have a uniform 35-year economic life policy, but they adopted a 35-year economic life consistent with its prior precedents, and consistent with what the pipeline had proposed. In doing so, FERC rejected calls for a longer economic life based upon abundant natural gas supply, as argued for by its own trial staff. However, the *Panhandle* decision also sets up a marker for rate case litigants that may argue for shorter economic lives based upon public policies and market preferences that could reduce future natural gas demand. A shorter economic life would result in higher depreciation rates.

Certainly, future reduction to natural gas demand is a prevailing argument made by opponents to new pipeline infrastructure in the context of FERC's "public need" determination under NGA Section 7, and has previously been entertained by some of the FERC commissioners. And, while the future use of natural gas was discussed in NGA Section 7 orders issued concurrently with *Panhandle*, as well as in depreciation testimony and briefs filed in the underlying rate case proceeding, the debate was neither acknowledged nor discussed in the Panhandle text. This suggests that, for ratemaking purposes, FERC may not be ready to deviate too far from its prior precedent.

4. Affiliate contracts remain subject to intense scrutiny.

A prominent issue in several orders voted on at FERC's December 2022 open meeting, including *Panhandle*, concerned affiliate contracts and whether they result in just and reasonable rates. The *Panhandle* NGA Section 4 rate case was borne, in part, out of an investigation under NGA Section 5 into the affiliate relationship between a pipeline and a storage company. A holdover from that investigation considered whether the *Mobile-Sierra* doctrine protected a negotiated rate agreement between the affiliates and whether the rate therein could be passed on the pipeline's customers. FERC demurred on the larger issue of whether Mobile-Sierra could apply to affiliate contracts and did not issue an order as to the justness and reasonableness of the contract rate, but instead as to the justness and reasonableness of the rate based onto the pipeline's ratepayers, effectively requiring the pipeline to absorb the difference. Otherwise, FERC reiterated its precedent that a pipeline typically has a heavier burden of proof to support the need for affiliate contracts, or the rates contained therein, when it is in a rate case posture. FERC found that in some instances the pipeline met its burden while in other instances it did not.

5. FERC generally defers to the pipeline on rate design.

Pipeline rate design constituted another important topic in the *Panhandle* proceeding, including how the pipeline classified and allocated costs to different cost centers and classes of ratepayers. In almost all instances, FERC deferred to the pipeline on matters of rate design, including whether to continue an existing rate design or to adopt proposed changes. This is not surprising. Third parties seeking changes to a pipeline's rate design have an elevated burden of proof under NGA Section 5. They must demonstrate that the existing rate design is unjust and unreasonable and that their proposed changes are just and reasonable. A pipeline has the same burden, but often has access to additional data that makes it easier to overcome. One of the few areas where FERC rejected the pipeline's proposed rate design concerned changes in the allocation of costs to small customers, a class of customers that FERC has traditionally protected.

HIFIA A Bi-Partisan Bill to Build Out Hydrogen Transport Infrastructure

Ben N. Reiter, Emily P. Mallen, Christopher A. Treanor, and Susan H. Lent, Akin Group

On March 2, 2023, a bi-partisan group of Senators introduced a package of legislation dubbed the Hydrogen Infrastructure Initiative aimed at facilitating the build out of the hydrogen infrastructure necessary to transport, store, and deliver hydrogen. The Hydrogen Infrastructure Initiative includes four separate pieces of legislation: (i) the Hydrogen for Ports Act (S.647), (ii) the Hydrogen for Industry Act (S.646), (iii) the Hydrogen for Trucks Act (S.648), and (iv) the Hydrogen Infrastructure Finance and Innovation Act ("HIFIA") (S.649). While all four bills could play an important role in assisting the development of hydrogen infrastructure in the U.S., HIFIA is likely to be of outsize importance given its focus on addressing one of the most significant barriers to the widespread deployment of clean hydrogen: the ability to cost-effectively transport it from where it is produced to where it will be consumed. Senators Chris Coons (D-DE) and John Cornyn (R-TX) are the initiative's original co-sponsors.

Hydrogen has a potentially large role to play in decarbonizing numerous sectors of the economy. But unlocking hydrogen's potential may require it to be transported long distances via pipeline, long considered the most cost-effective transportation method. At present, there are roughly 1,600 miles of hydrogen pipelines in the U.S., most of which are concentrated along the Gulf Coast.

If the clean hydrogen economy is truly going to scale up in the next decade to the extent many predict, the U.S. will need to build out many more miles of hydrogen pipelines or convert existing pipelines to carry hydrogen. HIFIA, if passed, would represent a promising first step towards resolving regulatory uncertainties and assisting with financing these energy transition projects. It is modeled off of WIFIA (for water infrastructure), TIFIA (for transit infrastructure) and the recently enacted CIFIA (for carbon transport infrastructure), and is comprised of the following four elements:

1. **HIFIA Pilot Program** - The bulk of HIFIA is devoted to establishing a pilot program pursuant to which the Department of Energy ("DOE") would provide grants, long-term low-cost supplemental loans or technical assistance to hydrogen transport, storage or delivery projects, including new hydrogen pipelines, and retrofitted natural gas pipelines that can transport at least a blend of hydrogen and natural gas and rail projects. In selecting projects to receive HIFIA grants or loans, DOE would be required to identify projects that, to the extent practicable, are large capacity, common carrier infrastructure, aid in creating hydrogen economies of scale, and, among other things, generate the greatest benefit to low-income or disadvantaged communities. DOE would be required to coordinate the HIFIA Pilot Program, to the maximum extent practicable, with the Infrastructure Investment and Jobs Act's $8 billion hydrogen hub program.

2. **Broadening Title XVII Innovative Clean Energy Loan Guarantee Program** - HIFIA would make clean hydrogen projects eligible to receive a DOE loan guarantee under Title XVII's Innovative Clean Energy Loan Guarantee Program. Under Title XVII, which is administered by DOE's Loan Programs Office (LPO), commercial scale, first-of-a-kind projects that reduce greenhouse gas emissions and are defined as "eligible projects" are able to receive DOE-backed loan guarantees. Although Title XVII currently includes "[h]ydrogen fuel cell technology for residential, industrial, or transportation applications" in its definition of eligible projects, HIFIA would substantially broaden Title XVII to include any "[h]ydrogen technologies applicable to 1 or more end-use sectors, such as power generation, transportation, aviation, storage, industrial, and chemicals, including hydrogen fuel." Given that LPO now has in excess of $60 billion in loan authority under Title XVII to utilize, HIFIA's expansion of the definition of eligible projects could be a significant boost to hydrogen projects, including hydrogen transport infrastructure. If the program is implemented like CIFIA, the DOE is expected to distribute the funds as low cost loans instead of grants. Applicants will need to be aware of the terms of the loans and particular DOE-specific requirements.

3. **Required Regulatory Assessment** - HIFIA would require the Federal Energy Regulatory Commission ("FERC"), Surface Transportation Board ("STB") and Pipeline and Hazardous Materials Safety Administration, in coordination with DOE, to perform an assessment of their collective jurisdiction over the siting, construction, safety, and regulation of hydrogen transportation infrastructure, including the blending of hydrogen in natural gas pipelines. If the required assessment discloses that additional authority is needed by these agencies to support the deployment of hydrogen transport infrastructure, they would be required to submit a report to Congress within 270 days of HIFIA's enactment identifying what additional authority they required. The agencies would also be responsible for identifying HIFIA pilot projects' eligibility to recover costs under FERC or STB regulated rates. HIFIA's required regulatory assessment could help to resolve areas of considerable uncertainty regarding the regulation of hydrogen pipelines.

4. **Hydrogen Pipeline Corridors Study** - HIFIA requires DOE, the Environmental Protection Agency, and the Council on Environmental Quality, along with other relevant agencies, to conduct a study assessing the potential layout of hydrogen pipeline corridors. The agencies would also be

required to consider other aspects of building out hydrogen infrastructure such as costs, the ability to site pipelines within existing linear infrastructure corridors, the impact of hydrogen leakage, a framework for monitoring and reporting hydrogen leakage, and the reduction in carbon intensity based on blending various amounts of hydrogen into natural gas.

While there is not sufficient political will to immediately pass these proposals, these bills are likely to come up for debate as Congress works towards reforming federal permitting across energy projects.

In-House Counsel Q&A With Emma Kerr, Phillips 66 Managing Counsel, Transactions, Real Estate And Procurement

Interview by Parker Lee, McDermott Will & Emery LLP

PL: Please tell us a little bit about Phillips 66, your role on the legal team, and some of the day-to-day functions you cover.

EK: As Managing Counsel, Transactions, Real Estate and Procurement, I oversee a team that works not only within the midstream commercial and transactional space, most specifically the gas gathering and processing deals, but also the real estate and procurement functions of the company. Prior to my recent move into this role, I was entrusted with working with Phillips' Midstream Business Development team, specifically within the crude pipeline space, as well as advising the company with respect to its joint ventures, in the creation, governance, and operation thereof. Also, as a member of the Commercial Transactions team within the Legal Department, I've been fortunate to do several M&A transactions with our Corporate Business Development team.

PL: You have one of the coolest backgrounds prior to becoming a lawyer out there! How has that experience shaped your career as a lawyer, and do you find yourself using some of those skills on a day-to-day basis?

EK: Not sure about the "coolest background" comment, but I'll take it! I come from a performing arts background. My first career was as an actress, both in theater and film, and was the career I thought I would have forever (as all people in the arts think at one point)! There was a point in college that I knew I loved the law and was extremely interested in that path; however, through my Con Law professor's endless mentoring and wisdom, I decided to pursue the performing arts path. Several years later, I realized that that path wasn't for me anymore, at least not in the professional sense, and proceeded to law school.

My legal career started in litigation, and many people assume that the acting career would be a significant benefit, especially in the courtroom. And that may very well be true for others; however, it definitely was not the case for me. But aside from that aspect, I think being in the performing arts has given me a resiliency, drive, and dedication to the work.

PL: Phillips 66 is a huge company that touches so many different parts of the energy industry. What are some of the things that you have learned about the energy industry since joining Phillips 66?

EK: I think the biggest thing that I have learned is that it's amazing how intricate and complex the energy world is. Each segment of the energy value chain is so different, and how they interplay with each other is such a balancing act.

PL: For private practice lawyers considering a move in-house, what advice would you share or encourage people to consider before making that move?

EK: In-house is very different from private practice. And making the move and really learning to be an in-house lawyer is a transition and takes time. Learn the business—all of the business—as best you can. I like the tree/forest analogy: You need to see the trees, but also need to understand how each tree affects the whole forest. While at a law firm, you may fight tooth and nail for that one tree; as an in-house lawyer, you may realize that that one tree is not quite as important in the large scheme of operations and value chain. Your role is to advise and counsel the business on how they can best make the company be of the most value to its customers, shareholders (if any), employees, and industry, all while protecting it.

PL: You have a big job and lots of responsibility at the office. You have an even bigger job and more responsibility at home with two young children. Do you have any tips to share on juggling your family and professional lives?

EK: As any parent knows, it can be so hard to balance work and home life. And I think there has to be the understanding that balance means that maybe some things get missed. Maybe that extra dish stays in the sink longer than I would like. Maybe I only get four hours of sleep versus six. Or maybe I don't get to review that one contract during the day because I'm with a sick child, but I review it that night after they go to bed. As a solo parent, I have to ensure that my time during the week is very structured, especially on the home front. Also, it's definitely a privilege I'm lucky to have, but if you are able to find and work for someone who supports your situation and trusts you to get your job done, that helps alleviate some of the stress of "how can I do this?". Otherwise, another good tip is to have a great babysitter!

PL: I know you are a big reader, especially about the clandestine government services. Reading anything interesting right now?

EK: I do love my spy books! I'm just started *In the Enemy's House*, by Howard Blum, which details a counterintelligence mission involving a codebreaker and FBI supervisor that uncovered an extensive network of KGB spies. Also, I bought my dad the complete set of John Le Carre novels, which I'm hoping he'll lend to me when he finishes. I finished *The Spy Who Came in from the Cold* recently and will probably read *The Looking Glass War* next. I'm also delving into the wonderful world of toddler parenting books.

Pennsylvania Court Upholds Cross-Unit Drilling Under Act 85

Bridget D. Furbee and Nathaniel I. Holland, Steptoe & Johnson PLLC

On January 24, 2023, the U.S. District Court for the Middle District of Pennsylvania held that Act 85 of 2019, which permits drilling horizontal oil and gas wells across existing drilling units, is not unconstitutional.

Lessor Warner Valley Farm LLC sued Lessees SWN Production Co. LLC and Repsol Oil & Gas USA LLC, alleging that they breached the terms of a 2006 lease by drilling a well that crossed the boundary of the lessor's unit. Warner Valley also sought a declaration that Act 85 was void under the Contracts Clauses of the U.S. and Pennsylvania constitutions.

The District Court granted summary judgment to both lessees, ruling that Act 85 was valid and that the 2006 lease permitted cross-unit drilling. The District Court found that Act 85 did not impair the 2006 lease because the Act does not affect leases that expressly forbid cross-unit drilling. Thus, while Act 85 effectively lifts the 330-foot regulatory barrier to cross-unit drilling, it leaves the parties free to contractually prohibit cross-unit drilling. In addition, Act 85's requirement that the lessees reasonably allocate production between existing units did not impair an existing provision of the lease.

The District Court further held that even if Act 85 substantially impaired the 2006 lease, it was justified by its goals of reducing the economic costs and environmental impacts of oil and gas drilling. Finally, the District Court held that the 2006 lease did not forbid cross-unit drilling, citing the broad terms of the lease's pooling and unitization clause.

FERC Opens 2023 With Leadership Transition

Karl Pielmeier III and Sarah Tucker, Sidley Austin LLP

Former U.S. Federal Energy Regulatory Commission (FERC or the Commission) Chairman Richard Glick has officially departed the independent Commission after failing to secure a reconfirmation hearing before the Senate in December 2022. Glick's departure leaves the Commission with a 2–2 split between Democrats and Republicans that could stall a number of major initiatives that were ongoing under the former Chairman and the Commission's Democratic majority.

On January 3, President Joe Biden named Commissioner Willie Phillips, who is currently serving a FERC term that expires in June 2026, as acting Chairman to temporarily succeed Glick. The White House has not confirmed when it will name a new Commissioner to the five-seat Commission or who is being vetted for Glick's now-vacant seat. Some speculate that a successor to Glick as permanent chair will not be named until summer; the term of Commissioner James Danly is set to expire on June 30.

With a deadlocked Commission, a number of agenda items furthered may be left in limbo — at least for the near future. These include a series of natural gas policy statements that the Commission converted to draft form in March 2022 along with power transmission initiatives aiming to respond to capacity and reliability challenges.

Other recent ambitious policy items may be affected by Glick's absence. The past few months have seen heightened FERC involvement in ratemaking cases. Last month, FERC issued an order (RP19-78) setting a return on equity of 11.25% for Energy Transfer LP subsidiary Panhandle Eastern Pipe Line Co. LP in its first fully litigated natural gas pipeline rate case in almost a decade. Commissioner Allison Clements indicated that she expects the order will "provide important guidance on [FERC's] approach to natural gas rates in coming years." On the power side of FERC's docket (Docket No. ER22-233-000), Portland General Electric Co.

recently submitted a proposed settlement of the company's first rate case in more than 20 years, which if accepted would result in a reduction in the company's requested return on equity from 10.36% to 10.0%. In another rate case, addressed on January 19 in the Commission's first meeting of 2023, FERC conditionally accepted the filing by three Southern Co. subsidiaries in response to a 2022 show-cause order with respect to the companies' formula rate protocols, subject to a further compliance filing.

Meanwhile, presiding over his first monthly meeting as acting chairman, Commissioner Phillips promised to prioritize grid reliability, transmission reforms, and environmental justice and announced plans to hold a roundtable on environmental justice and equity on March 29.

DOE Announces Over $4b In Energy Transition Project Tax Credit and Grant Programs

Sarah Tucker and Curtis Hart, Sidley Austin LLP

The U.S. Department of Energy ("DOE"), alongside the Internal Revenue Service and Department of the Treasury, announced plans to implement programs funded by the Inflation Reduction Act and the Bipartisan Infrastructure Law: the Low-Income Communities Bonus Credit Program (48(e)), the Qualifying Advanced Energy Project Credit (48C)), and the Advanced Energy Manufacturing and Recycling Grant Program. Together, these programs will make available more than $4 billion in federal tax credits and grants for energy transition projects in an effort to "accelerate domestic clean energy manufacturing and ensure traditionally underserved communities benefit from clean energy technologies."

The DOE describes the Low-Income Communities Bonus Credit Program as the most significant tax incentive in U.S. history to promote clean energy investments in communities that might otherwise suffer economically due to transition away from fossil fuels. The bonus tax credit is allocated to 1.8 gigawatts of eligible solar and wind capacity per year across four categories, including 700 megawatts ("MW") for projects located in low-income communities, 200 MW for projects located on tribal lands, 200 MW for qualified low-income residential building projects, and 700 MW for qualified low-income economic benefit projects (each as further described in the Initial Guidance). The program prioritizes certain equity goals described in the announcement (e.g., increasing access to renewable facilities in underserved communities, encouraging new market participants, and providing benefits to communities overburdened by environmental impacts), and the DOE and Treasury have committed to continue to engage with clean energy, environmental justice, and community-based organizations to further the program's equity goals.

The goal of the Qualifying Advanced Energy Project Credit is to expand domestic manufacturing capacity and quality jobs for clean energy technologies, reduce greenhouse gas emissions in the industrial sector, and secure domestic supply chains for critical materials for clean energy technology production. Bolstered by $10 billion of investments into the credit from the Inflation Reduction Act, the Treasury and IRS (in partnership with the DOE) announced their intent to release approximately $4 billion in this first round of tax credits—with $1.6 billion of the allocation set aside for projects in coal communities and an investment tax credit of up to 30% of qualified investments for projects meeting the prevailing wage and apprenticeship requirements.

Last, the Advanced Energy Manufacturing and Recycling Grant Program opened applications for its first round of grants, consisting of $350 million of the overall $750 million available under the program. The program provides grants to small- and medium-size manufacturers that have annual sales of less than $100 million, fewer than 500 employees, and annual energy bills between $100,000 and $2.5 million for projects to build new or retrofit existing facilities to produce or recycle advanced energy products in former coal communities. The DOE provided a mapping tool showing eligible communities for the projects, which must be located in census tracts where (a) coal mines have closed since December 31, 1999, (b) coal-fired power plant units have closed since December 31, 2009, or (c) census tracts are immediately adjacent to (a) or (b). Further, the program will prioritize applications from minority-owned firms, and applicants are required to submit a Community Benefits Plan with its application to demonstrate the project's impact and benefits to the host community and region.

Massachusetts Land Court Indicates That Consistency Is Key In Applying Zoning Requirements To Solar Projects

Brian Levey and Hilary Jacobs, Beveridge & Diamond

The Massachusetts Land Court recently struck down a local planning board's denial of an application for a permit for a large-scale solar project as arbitrary and capricious based on conflicting decisions the board had recently made on applications for similar projects.

In *Ironwood Renewables, LLC v. Town of Carver*, Land Court No. 21 MISC 000488 (Oct. 27, 2022), Plaintiff Ironwood Renewables, LLC ("Ironwood") applied for a permit to construct and maintain a 3.26-megawatt ground-mounted solar photovoltaic installation. As required by the local zoning bylaw, Ironwood included in its application a list of the six abutting properties and the project's proposed setbacks from these properties. The zoning bylaw required that large-scale solar projects meet either (1) a minimum 200-foot setback from all abutting properties or (2) a reduced setback from all "direct abutters" based on a waiver request. The zoning bylaw did not define the term "direct abutters." Still, Town Counsel had previously advised the board to interpret that term as "only those abutters directly impacted by the reduced setback." Ironwood's setback plan included (i) requests for waivers to reduce setback to 50 feet from four properties that shared a common property line and (ii) no change to the 200-foot setback for the remaining two properties.

The planning board denied the application on the grounds that Ironwood had not complied with the requirement to submit waivers from the properties of all "direct abutters." The Court found the board's denial to be "a paradigm of arbitrary and capricious decision-making" based on its inconsistency with recent decisions to grant permits to two similar projects with reduced setbacks where the applicants had sought waivers from "direct abutters"—*i.e.*, those properties located along a property boundary that would be subject to a proposed reduced setback—but had not provided waivers for *all* abutting properties. In the absence of any explanation for this change in interpretation of the meaning of the term "direct abutters," the Court reversed the board's decision and instructed it to issue Ironwood the permit for its proposed solar project.

Following this decision, solar permit applicants in the Town of Carter need only seek waivers for reduced setbacks from those properties that directly share a property line with a proposed reduced setback. The Court's opinion also signals to other local jurisdictions that it will hold local planning and zoning boards to some consistency in their decision-making. Solar project applicants should review prior solar applications and decisions in a municipality which may provide guidance on how to best position applications.

Ninth Circuit Causes A Ripple: Reinstates Trump-Era Clean Water Act Rule Governing State Certifications

Eric Christensen and Allyn Stern, Beveridge & Diamond

On February 21, 2023, the U.S. Court of Appeals for the Ninth Circuit issued the latest in a series of opinions involving the Trump Administration's rule interpreting Section 401 of the Clean Water Act ("CWA"). *In re Clean Water Act Rulemaking*, __ F.4th __, 2023 WL 2129631. The effect of the Ninth Circuit's decision is to reinstate, at least temporarily, a rule issued by the Environmental Protection Agency (EPA) during the Trump Administration that significantly scaled back state powers under Section 401. The impact of the Ninth Circuit's decision is likely to be short-lived, as EPA is on track to issue a new rule interpreting Section 401 that will largely restore state and tribal powers.

CWA Section 401 requires the sponsor of any project requiring a federal permit that will result in a discharge of pollutants into the waters of a state to obtain a water quality certificate from the affected states or tribes. States may issue or deny a water quality certification and include conditions on a certification. Section 401 provides up to one year from the date a certification is requested for the state or tribe to act, and if no action is taken, the state's authority is waived.

Application of Section 401, especially the one-year limitation, has proven difficult and controversial, producing a difficult and contradictory body of law from the federal appeals courts. In June 2020, the EPA adopted a rule governing certifications under Section 401 that strictly interpreted Section 401's one-year clock and restricted the states' substantive powers under Section 401. Several states, tribes, and environmental groups challenged the rule in the U.S. District Court for the Northern District of California.

As that litigation was getting underway, President Biden was elected, and the Trump-era Section 401 rule was among a list of Trump actions the new Administration directed EPA to revisit on its first day in office. On June 2, 2021, EPA issued a Notice of Intent to replace the Trump-era rule with a new one. Therefore, EPA requested a voluntary remand of the 2020 rule to reconsider and revise it. The District Court agreed to remand the rule but also vacated it. The District Court's decision to vacate the rule was appealed to the Ninth Circuit and, in an unusual move, the U.S. Supreme Court issued a temporary stay of the District Court's decision to vacate the 2020 rule during the pendency of the Ninth Circuit appeal.

The Ninth Circuit's decision reaches an important question of administrative law—whether district courts have the power to vacate administrative rules when an agency requests a voluntary remand of a rule for further consideration. The Ninth Circuit concludes that, under the Administrative Procedures Act, courts can vacate an agency action only if they first determine the agency action is unlawful. Accordingly, the court concluded that the District Court overstepped its authority by vacating the EPA's 2020 rule without first concluding that EPA had acted unlawfully.

The decision effectively reinstates the Trump-era EPA's rule governing state and tribal certifications under Section 401. However, that rule is likely to be replaced soon. EPA completed the public comment period on its 2021 proposal to replace the Trump-era rule in August 2022 and indicates that it expects to issue its new final rule this spring.

CWA Section 401 is a key requirement for any project requiring a federal permit that could impact water quality. Seeking a Section 401 certification is required for, for example, pipelines, hydroelectric projects, and other energy infrastructure requiring a FERC permit and for various construction activities requiring a dredge-and-fill or NPDES permit under the CWA. Sponsors of such projects should pay careful attention to the restrictions currently in place on state action under Section 401 and how state discretion will change under the new rule EPA is likely to issue soon.

The Decisive Decade: The Race To Net-Zero Gets Underway

The US made its energy transition intentions clear when the administration announced its commitment to reach net-zero emissions by 2050—the clock is ticking, but how will M&A play a part?

Jay Cuclis, Arlene Arin Hahn, Michael Rodgers, and David Strickland, White & Case LLP

In December 2021, President Biden announced a new target for the country to achieve a 50 to 52% reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030. To put that into context, in 2020, net greenhouse gas emissions were approximately 17% below 2005 levels.

As a result, fossil fuel operators are now aggressively trying to reduce their emissions. Sustainable energy companies from renewable natural gas to renewable methane are being bought up by oil and gas super-majors, whose balance sheets have expanded thanks to the surging price of energy and fossil fuels in the past two years. By acquiring these assets and incorporating them into their existing infrastructure, thereby creating larger diversified energy companies, these groups have the potential to establish profitable renewables businesses. The bottom line is that fossil fuel companies are adapting to this new environment, and one of the fastest ways to achieve this transformation is through buying rather than building, meaning that there is likely to be substantial M&A activity in this sector. Case in point: Chevron Corp made its biggest investment to date in alternative fuels when it acquired biodiesel maker Renewable Energy Group for $3.15 billion in February 2022.

A Game-Changing Law

A major catalyst for investment in energy transition is the landmark Inflation Reduction Act (“IRA”), which Congress passed in August 2022. It is the most sweeping legislative development in the history of renewable energy income tax incentives. The IRA has reset existing tax credits while introducing new incentives for a variety of renewable energy sources and projects in what will amount to an expenditure of more than $400 billion.

Under the IRA, extant tax credits for traditional solar and wind projects (the value of which, under prior law, had begun to taper off significantly), have been restored to their original dollar value and extended until 2032—and potentially later if emission targets are not achieved in that time. The tax credits are available on the condition that claimants comply with new “wage and apprenticeship” requirements designed to ensure that construction workers are paid prevailing wages, and qualified apprentices registered with the U.S. Department of Labor are used for projects. Moreover, in what will likely serve as a significant boon to the burgeoning carbon-capture, utilization and storage (“CCUS”) industry, under the IRA, tax credits associated with carbon oxide sequestration will enjoy both significant increases in credit value and significant decreases to applicable minimum capture thresholds.

Additional incentives under the IRA include tax credits for standalone battery storage, clean hydrogen, and manufacturers of components for qualifying clean energy projects and facilities. The legislation also provides for new and potentially game-changing ways to monetize tax credits. This includes transferability provisions—which, for the first time, allow tax credits to be bought and sold between taxpayers—as well as so-called “direct pay” provisions, which allow for taxpayers in loss positions to simply collect cash from the Treasury Department rather than being forced to wait until they have taxable income in order to make tax credit claims.

Focus on Energy Security

There is a notably different emphasis in how U.S. energy incumbents are attempting to decarbonize. Unlike in Europe, where companies are far more focused on renewables, U.S. businesses are directing more investment toward CCUS. This extends beyond the energy sector into adjacent applications.

For example, in December 2022, ExxonMobil, the largest oil and gas company in the U.S. by market capitalization, partnered with Mitsubishi Heavy Industries to deploy the latter’s carbon-capture technology as part of ExxonMobil’s end-to-end carbon-capture and storage services for heavy-emitting industrial customers.

There are two key reasons for the growing investment in CCUS. Rapidly weaning the world off carbon-based fuels will be incredibly challenging because of their widespread accessibility and lower cost relative to renewables. Then there is the question of energy security—renewables continue to face energy storage constraints. Prevailing battery technology, lithium-ion cells, are limited by raw material scarcity and have a relatively short effective operating life.

Private financing is working to solve this. For example, in December 2022, Houston headquartered energy infrastructure company Schlumberger and Saudi Aramco's corporate venture arm backed a $100 million Series A round for EnerVenue, a California startup developing long-life nickel-hydrogen batteries. In due course, advanced battery technologies have the potential to further unlock renewables' contribution to the overall energy mix.

In the shorter term, CCUS offers a timely solution for reducing carbon emissions to help offset the impact of the continued use of traditional energy sources. Like renewables, the space has received a substantial boost from the IRA, which has significantly increased the tax credit value and decreased the applicable minimum capture thresholds for carbon-capture projects. All of this will go a long way toward the government's goal of achieving net-zero by 2050.

U.S. Supreme Court Holds Employees Paid On A Day-Rate Basis Entitled To Overtime

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The U.S. Supreme Court recently held that paying an employee on a "day-rate" basis, even when that day rate was significantly higher than the applicable weekly threshold, does not satisfy the salary-basis test under the white-collar exemptions to the Fair Labor Standards Act ("FLSA"). This case could significantly impact energy sector employers and others who pay otherwise exempt "day-rate" employees. The Court's ruling in *Helix Energy Solutions Group, Inc., et al. v. Hewitt* is important because even highly compensated employees may be eligible to receive overtime payments if their compensation structure solely rests on a day rate.

The FLSA's "White-Collar" Exemptions

Generally, the FLSA requires employers to pay covered employees' overtime at no less than one-and-one-half times their regular rate of pay for all hours worked over 40 in a workweek. The FLSA exempts certain employees from overtime pay provided that certain criteria are met. Among those exemptions are the executive, administrative, or professional employee exemptions, commonly referred to as the "white-collar" exemptions.

The requirements to qualify for these exemptions include: (1) the employee must be paid on a "salary basis"; (2) the employee's salary must be at least $684 per week; and (3) the employee must perform the required duties associated with the exemption. In order to meet the salary-basis test, an employee must regularly receive a predetermined amount of compensation each pay period on a weekly, or less frequent, basis that is not reduced because of variations in the quality or quantity of the employee's work. *See* 29 C.F.R. § 541.602(a) ("Section 602(a)").

The Lawsuit

Michael Hewitt worked as a tool-pusher and supervisor on an offshore oil rig from 2014 to 2017. He regularly worked 84-hour weeks for 28 days at a time. He was paid between $963 and $1,341 per day. His annual earnings exceeded $200,000—well above the $455 per week salary threshold required for the white-collar exemptions at that time (it is now $684 per week). Believing that Hewitt's salary and duties squarely fell within the requirements of the bona fide executive exemption, the company, Helix Energy Solutions Group, did not pay him for any overtime.

Hewitt sued to recover unpaid overtime. The district court in Texas originally rejected his argument, stating he was properly classified as exempt. Hewitt appealed to the Fifth Circuit Court of Appeals, which sided with him. The Fifth Circuit reasoned that the salary-basis test requires an employee to be paid the same amount of salary on a weekly basis or less frequently, irrespective of the days worked in that workweek. Because Hewitt's pay varied by the number of days worked in a workweek, the Fifth Circuit concluded that it didn't meet the regulatory definition of a "salary" for purposes of the white-collar exemptions.

The Supreme Court's Decision

In a 6-3 decision authored by Justice Elena Kagan, the Supreme Court upheld the Fifth Circuit's ruling, finding that the pay structure didn't meet the "salary basis" test of the white-collar exemptions, entitling Hewitt to seek overtime for hours worked beyond 40 a workweek.

The Court held that Section 602(a) "embodies the standard meaning of the word 'salary,'" and "demand[s] that an employee receive a fixed amount for a week no matter how many days he has worked[.]" The Court further held that "nothing in that description fits a daily-rate worker, who by definition is paid for each day he works and no others." In other words, "[a] daily-rate worker's weekly pay is always a function of how many days he has labored. It can be calculated only by counting those days once the week is over—not, as § 602 requires, by ignoring that number and paying a predetermined amount."

The Court rejected the company's argument that, if an employee was paid on a weekly (or less frequent) basis according to some predetermined rate that exceeded the required weekly amount, the salary basis was met.

Any employer who pays its employees via a day rate but does not pay them for overtime hours should carefully review its pay practices and exempt classifications.

Protective Measures Energy Companies Should Consider After Supreme Court Opens Door For Overtime Wage Lawsuits

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The U.S. Supreme Court's decision in *Helix Energy Solutions Group, Inc. v. Hewitt* (No. 21-984) will likely impact companies within the oil and gas industry. The Court held that highly compensated supervisors who typically would be exempt from the overtime compensation provisions of the Fair Labor Standards Act ("FLSA") are entitled to time-and-a half pay for hours worked over 40 hours in a workweek because they receive a daily rate rather than a fixed annual salary.

Make no mistake: the next wave of wage and hour litigation is coming, and it will be costly. Many companies in the oil and gas industry pay their employees and subcontractors based on daily rates or have master service contracts with other companies that do so. The following are some of the steps that companies can take to minimize their risks and prepare:

1. Take stock of potential direct liability: If some employees are paid based on a day rate, re-examine the exempt / non-exempt categories immediately.

2. Consider insurance for potential defense costs: Most employment practice liability coverage excludes wage and hour liability. An endorsement for wage and hour coverage may be available for purchase, although such coverage usually only covers defense costs (not liability) and has a lower sublimit. However, some risk transfer may be better than no risk transfer.

3. Consider lowering potential litigation exposure, particularly to class actions: Employees may be required to sign a mutual agreement to arbitrate certain employment-related disputes (not all),which can include a class action waiver. Contractors may also be required to agree to arbitration and class action waivers. This will greatly reduce potential litigation exposure.

4. Shore up indirect litigation risks from third-party contractors:

- Revise master service agreements to include indemnification for wage and hour claims by a vendor's employees and subcontractors;
- Require vendors to enter into mutual arbitration agreements with their employees and subcontractors that would inure to the benefit of their customers; and
- Consider high-grading existing vendor contracts by spend and vendor type to identify higher risk exposures before approaching vendors about re-negotiating agreements to include the above provisions.

DC Circuit Delivers Valentine To Solar-Battery Hybrids

Eric Christensen and Brook Detterman, Beveridge & Diamond

On February 14, 2023, the U.S. Court of Appeals for the District of Columbia Circuit issued its opinion in *Solar Energy Industries Association v. Federal Energy Regulatory Commission* (___ F.4 ___, 2023 WL 1975079), providing a clear path for hybrid solar-battery and wind-battery projects to qualify for benefits under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The decision upholds the Federal Energy Regulatory Commission's "send-out" approach to PURPA's 80-megawatt ("MW") capacity limit, which measures the capacity of a generator based on the nameplate capacity of the total project to inject alternating current ("AC") power onto the grid, rather than the capacity of individual generating units that are components of a generating project.

PURPA provides substantial benefits to "qualifying small power production facilities" or "Qualifying Facilities," which are renewable energy generators with capacity of 80 MW or less. Chief among these benefits is PURPA's "must-offer" requirement, which guarantees that Qualifying Facilities can sell their power to incumbent utilities at the purchasing utility's "avoided cost" rate. The question addressed in the DC Circuit's decision was whether Broadview Solar, a solar-storage hybrid facility in Montana, is a "Qualifying Facility."

The Broadview Solaris facility has a 160-MW direct current ("DC") solar array, a 50-MW DC battery, and an inverter with 80 MW of AC output capacity. Initially, FERC ruled that Broadview is a Qualifying Facility based on its long-held view that PURPA's capacity limitation should be determined by how much power the facility can "send out" to the grid. Because Broadview's inverter allows no more than 80 MW of AC power to be delivered to the grid, the facility's "send out" capacity meets PURPA's 80 MW limit.

Utility interests challenged this ruling on rehearing, and FERC reversed course, concluding that the 160-MW DC solar array meant Broadview exceeded the 80-MW output limit and therefore was not eligible for PURPA benefits. This time, Broadview and renewable energy interests sought rehearing, and FERC again reversed course, returning to its traditional rule that a project's capacity should be determined by how much it can "send out." Under that rule, FERC concluded, Broadview's 80-MW inverter capacity established a limit of 80 MW on the amount of AC power the project could deliver to the grid. The fact that the project's solar array could produce up to 160 MW of DC power was irrelevant to the inquiry because the inverter limits the amount of power that can be delivered from the array to the grid at any given moment to 80 MW.

The utility interests appealed this conclusion to the DC Circuit. The DC Circuit rejected the appeal, upholding FERC's ultimate decision and concluding that (i) FERC's "send out" rule is a reasonable construction of PURPA because the statute is not clear how the 80-MW capacity limit should be calculated, and (ii) the "send out" rule is a reasonable approach in light of PURPA's language and legislative purpose.

Absent a reversal of the DC Circuit's opinion on further appeal, the ruling in *Solar Energy Industries Association v. FERC* provides the following key takeaways, which create a clear pathway for renewable energy projects that include energy storage to become Qualifying Facilities eligible for PURPA benefits.

- Under FERC's decision, as upheld by the DC Circuit, the capacity of a hybrid solar-battery project is measured by the amount of AC power the project can deliver to the grid through its inverter rather than by the capacity of individual project components that feed into the inverter.
- As a result of the decision, a hybrid project can meet PURPA's 80-MW limit if its inverters can deliver no more than 80 MW of AC power to the grid. This means that a developer can incorporate a battery storage device into a solar or wind project, and it will still be considered a PURPA Qualifying Facility—even if the capacity of the solar panels exceeds 80 MW of direct current (DC) capacity—so long as the inverter capacity does not exceed the 80 MW AC limit.
- Because adding battery storage to a solar project allows energy to be stored in the battery during hours of high solar intensity, the power can then be released from the battery and injected into the grid when the solar panels are not producing at maximum output. This improves both the project's capacity factor and the project owner's ability to maximize profits by selling power during hours when prices are high.

In short, the decision provides clear guidelines around which a project developer can optimize the design of its hybrid project while still meeting PURPA's 80-MW output limit.

PURPA is an important option for project developers to sell their output, and therefore remains a key driver of renewable energy expansion. With a clear roadmap, developers can now be confident that project configurations with inverters or other equipment limiting the project's "send out" capacity to 80 MW or less qualify for PURPA benefits. Developers can now optimize the solar arrays, storage equipment, and other project components to maximize the value of the project while relying on the "send out" rule to ensure that the project remains within the 80-MW PURPA limit.

The Basics Of Community Solar Projects And Their Application To Multifamily Projects

Andreas S. V. Wokutch, Robert Hillyer, Raghav Agnihorti, Brian Masterson, Brian Zoeller, and Brad Butler, Frost Brown Todd

In recent years, the share of energy produced in the United States through solar photovoltaic (PV) technology has increased exponentially. In 2008, installed solar capacity totaled a mere 0.34 gigawatts, but that figure has now reached 134 gigawatts. *See* Solar Energy Industries Association, Solar Energy Research Data. One particular type of solar facility that has contributed to this dramatic growth is community solar projects (CSPs). For example, in early 2022, the Biden administration announced a target of 25 gigawatts of community solar by 2025. *See* U.S. Department of Energy, DOE Sets 2025 Community Solar Target to Power 5 Million Homes. The U.S. Department of Energy's National Renewable Energy Laboratory defines a community solar project as a "distributed solar energy deployment model that allows customers to buy or lease part of a larger, off-site shared PV system." *See* Nat'l Renewable Energy Lab., Community Solar. The owner or developer of a CSP receives payment from customers "subscribing" to the CSP in exchange for certain economic, environmental, and social benefits (as more fully discussed in Section II). The attraction of the CSP model is its ability to make solar energy accessible to consumers who may not otherwise be able to install PV technology on their property due to insufficient solar resource (the amount of solar energy which reaches a specific location), lack of viable rooftop space, lack of property ownership, or insufficient capital to fund a PV project. These issues often arise in multifamily housing developments where tenants do not own the buildings they reside in but still have an unmet demand for access to renewables and the economic, environmental, and social benefits they bring. This article will provide a basic overview of CSPs generally, the value of CSPs to multifamily developments specifically, and certain legal and regulatory issues associated with CSPs that all stakeholders should understand.

I. CSP Basics and Value Proposition

As noted above, many individuals and organizations that desire to incorporate PV technology into their property are unable to do so because they lack the solar resource, viable rooftop space, property ownership, and/or capital to fund a PV project. In fact, the Department of Energy has estimated that only 22-27% of rooftops are suitable for solar PV installations. *See* Paul Denholm & Robert Margolis, Nat'l Renewable Energy Lab., Supply Curves for Rooftop Solar PV-Generated Electricity for the United States. Even where rooftops are feasible for an installation, many individuals and organizations lease their residential or commercial space. As such, they are likely unable to force or negotiate an installation with the owner of their property. The CSP model solves this problem by developing the project off-site, with potential locations being (among others) vacant or blighted land, landfills or any otherwise unproductive land with sufficient surface area to host a CSP. Consumers are then able to subscribe to that off-site CSP rather than navigating installation on their own property.

Additionally, it simply may be economically infeasible for many consumers to undertake the construction, maintenance, and operation of a rooftop or on-site solar project. CSPs present an opportunity for consumers of all income levels to receive the full benefits of a renewable energy source by allowing them to purchase or lease a smaller subsection of a larger solar facility. This allows them to capture certain economies of scale while still receiving the economic, environmental, and social benefits derived from a CSP.

So, what specifically are the economic, environmental, and social benefits of a CSP? Environmental and social benefits include: (a) an increase in the production of renewable energy, (b) a reduction in the carbon footprint of the CSP operator and subscribers, (c) expanding the overall availability of solar energy—particularly to low-income consumers, and (d) an increase in the ability of local communities to provide for their own energy needs.

Economic benefits from CSPs are also robust and include: (a) bill credits received from the project, (b) revenue from consumer subscriptions, (c) the right to sell renewable energy certificates (RECs), (d) various federal and state tax incentives, and (e) the ability to market to investors an increased focus on environmental, social, and governance (ESG) values/standards. While revenue derived from consumer subscriptions is self-explanatory, below is a brief description of the other economic benefits.

Bill Credits. Consumers receiving electricity from CSPs can receive credits on their utility bill in proportion to the electricity delivered to them. Where a PV system is located on-site, and the owner of the PV system and the consumer of the electricity produced by the PV system are the same, the electricity generated is delivered directly to the consumer. The local utility then "pays" for any electricity produced in excess of the electricity consumed by the customer. This concept is known as "net metering." *See* Nat'l Renewable Energy Lab, Net Metering. However, CSPs are generally located off-site, so the electricity produced is not delivered directly to the consumer. Instead, the CSP owner interconnects the project to the local utility's distribution grid and delivers power to the local utility. Then, the utility pays the CSP owner in the form of bill credits for any energy the CSP produces, and the CSP owner distributes the bill credits to subscribers in proportion to their purchased or leased area of the CSP. This indirect method of receiving utility bill credits is referred to as "virtual" net metering. In return for the bill credits, the subscribing individuals or entities pay a subscription fee to the CSP owner in conformance with the terms of their subscription agreement. This fee is typically either paid through monthly installments in relation to the amount of electricity generated and constitutes the primary revenue stream for CSPs.

It is worth noting that there are several different models for how bill credits may be distributed to subscribing consumers. The model described above is the most common. However, another common model, for example, is one where the utility pays all of the bill credits to the project owner who then sells the bill credits to subscribing consumers at a discounted rate. This results in a net offset on their utility bill.

RECs and SRECs. Another revenue stream for CSP owners is the sale of RECs and SRECs (solar renewable energy certificates) in states that have an active REC market. A REC is a market-based instrument which represents the property rights to the environmental, social, and other non-energy-based attributes of renewable energy generation. *See* U.S. EPA, *Renewable Energy Certificates (RECs)*. A REC is issued when one megawatt-hour (MWh) of electricity is produced and delivered to the grid from a renewable source, such as a CSP, and a SREC is issued for every MWh of electricity produced from solar energy resources. *See* U.S. EPA, Shared Renewables, [Shared Renewables](). In turn, RECs and SRECs can be sold on the renewable energy market either to utilities attempting to meet state-mandated renewable portfolio standards or to consumers (both individuals and organizations) wishing to establish that their energy usage is tied to renewable energy sources. Generally, states which have enacted Renewable Portfolio Standards have active REC markets for entities needing to meet those standards. *See* DSIRE, *Renewable and Clean Energy Standards (2022)*. In turn, states which have Renewable Portfolio Standards with specific solar carveouts tend to have active SREC markets. *See* DSIRE, *Renewable Portfolio Standards (RPS) with Solar or Distributed Generation Provisions*. However, SREC markets are currently only active in 11 jurisdictions. *See* Lori Bird, Jenny Heeter & Claire Kreycik, Nat'l Renewable Energy Lab., *Solar Renewable Energy Certificate (SREC) Markets: Status and Trends*. Organizations often pursue the purchase of RECs to show an increased corporate focus on ESG matters or to satisfy existing ESG corporate mandates.

Tax Incentives. Federal and state tax incentives can also make CSPs drastically more economically attractive for project developers. For example, the Inflation Reduction Act of 2022 (IRA) has recently extended and expanded two important tax credits for CSPs—the Section 48 Energy Investment Tax Credit (ITC) and the Section 45 Production Tax Credit (PTC). Pub. L. 117-169; 26 U.S.C. § 48. The ITC reduces the federal income tax liability of a project owner by a base credit rate of 6% of the qualified costs of a solar-generating system installed during the tax year. Eligible property includes, but is not limited to, (a) solar PV panels, (b) installation costs, (c) step-up transformers, and (d) energy storage devices. 26 U.S.C. § 48(a)(6). The base ITC rate of 6% is increased to an alternative rate of 30% if certain prevailing wage and apprenticeship requirements are met. 26 U.S.C. § 48(a)(10); 26 U.S.C. § 48(a)(11). These requirements include that "All laborers and mechanics involved in the construction of the project or the maintenance of the project for five years after project completion are paid wages at rates not less than prevailing wages." *Id*. Projects must also ensure that a percentage of total labor hours are performed by qualified apprentices. The PTC, on the other hand, allows owners and developers of solar-generating systems to claim an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by renewable energy sources and sold by the taxpayer to an unrelated person during the taxable year for a period of 10 years after a facility is placed into service. 26 U.S.C. § 45. The current tax credit is set at base 0.5 cents/kWh for projects over 1 MW or an alternative 2.6 cents/kWh for projects that either (1) are under 1MW or (2) meet prevailing wage and apprenticeship requirements. *Id*.

In addition to the base and alternative two-tiered tax credit structure, the IRA also provides for additional bonus credits on top of the ITC and PTC for projects located in energy communities, those that satisfy the domestic content requirement, and those that are located in low-income communities. CSPs that satisfy the domestic content requirement are eligible for a 10% increase in value of the ITC (e.g., an additional 10% to the 30% ITC) or 10% in value of the PTC (e.g., an additional 0.3 ¢/kWh to the 2.6 ¢/kWh PTC). 26 U.S.C. § 45Y(g)(11)(C). Similarly, projects sited in an energy community are eligible for an additional 10% increase in value of the ITC or PTC (e.g., an additional 10% to the ITC or an additional 0.3 ¢/kWh to the PTC). 26 U.S.C. § 45(b) (11)(B). Finally, CSPs that meet the requirements of a qualified solar facility can get an additional 10% ITC bonus for projects located in a low-income community or on Indian land or a 20% bonus if they are classified as qualified low-income residential building projects or qualified low-income economic benefit projects. 24 CFR § 5.2003; 26 U.S. Code §142(d)(2)(B). When combined, the IRA creates bonuses or add-on credits that can potentially push the ITC up to 70% of a project's qualified costs or 3.2¢/kWh in the case of the PTC. Furthermore, CSP developers may realize additional cost savings through the Modified Accelerated Cost-Recovery System (MACRS), which allows them to fully depreciate the cost of their PV system in as little as five years. I.R.C. § 168(I)(1).

Most states offer their own unique tax credits for both developers and producers of renewable energy. The multiplicity and variety of state tax credits places them beyond the purview of this article, but entities interested in developing or subscribing to a CSP should review local tax credits available in their jurisdiction.

ESG. Finally, through the purchase of RECs/SRECs—or by developing or participating in CSPs—organizations have an opportunity to demonstrate an increased focus on ESG corporate values/standards. Such efforts allow organizations to demonstrate a commitment toward increased production of renewable energy, a reduction in their carbon footprint, and the support of local communities. For the multifamily industry, there is also the ability to demonstrate a commitment to providing low-income residents with the benefits of solar power at a reduced cost and potentially even no cost. In turn, the foregoing can all be used to retain current investors and attract new investors, which increasingly demand that the companies in which they invest demonstrate tangible efforts to further ESG values/commitments.

II. Use of CSPs for Multifamily Housing Projects

The CSP model can be effectively incorporated into multifamily housing projects in a variety of ways to provide both tenants and owners with some of the benefits detailed above. However, an important initial consideration in determining how to pursue a CSP for a given multifamily project is whether it will be located on-site or off-site.

On-site projects generally involve rooftop PV installations, which require sufficient roof space to accommodate the project. For such projects, the property owner can act as either a CSP host or a behind-the-meter project host. By acting as a CSP host, the owner receives payment from either an electric utility or third party in return for allowing such utility or third party to install and operate a rooftop system on the owner's property through a lease. The CSP host could then subscribe to the third party's CSP, allowing it to receive benefits associated with a CSP without having to pay for the cost of installation or maintenance. Alternatively, by acting as a behind-the-meter project host, the owner would develop its own on-site system that contributes directly to the building's electricity supply. A behind-the-meter project allows the property owner to directly benefit from the energy cost savings and to pass those savings on to its residents.

Off-site projects could be located anywhere within the local electric utility's service area that has sufficient solar resources. For off-site CSPs, a primary concern of the property owner is likely whether their building is master-metered or multi-metered. Multi-metered buildings have one utility meter for each resident, with each resident being responsible for their own utility bill, while master-metered buildings have a single meter for the entire building, with the building owner typically paying the utility bill. For master-metered buildings, the property owner could subscribe to an existing CSP and receive credits towards the building's utility bill. Alternatively, the owner could purchase land off-site, develop their own PV system and apply the credits obtained to their master-metered building. As with an on-site, behind-the-meter project, the property owner would then decide how to best pass these cost savings to the residents. For multi-metered buildings, the property owner may either (1) choose to develop their own off-site CSP and work to get residents to subscribe in return for credits on their utility bill; or (2) sign up for bill credits at an existing CSP on behalf of their residents and then distribute credits accordingly.

The above options constitute some of the more common methods and pertinent considerations for incorporating a CSP into a multifamily housing project. However, in determining the most effective and efficient model for incorporating a CSP, owners will need to consider their own unique circumstances and tailor an approach that works best for them. Among other factors, property owners will need to consider the minimum size of the CSP or CSP subscription necessary to benefit their property, the available square footage on their property for such a project (or the cost of purchasing property off-site), and the level of demand among their tenants for such a program. All of these factors play an important role in deciding how to best incorporate a CSP into a multifamily housing project.

III. Legal and Regulatory Issues Associated with Multifamily Community Solar Projects

A. Legal Issues

Multifamily CSPs present a number of unique legal issues that potential owners/developers should consider. First, there are recurrent issues that must be handled when drafting subscription agreements (also referred to as power purchase agreements), which are the contracts entered into between the CSP owner and subscriber. If the CSP is directly owned by the multifamily property owner, and the subscribers are residents, then the subscription agreements will be with tenants and need not be opened up for negotiation. However, if the subscription agreement is between a multifamily property owner desiring solar energy and a third-party CSP owner, then the contract may be open for negotiation. If the multifamily property owner is a CSP host, then the property owner would also need to negotiate a lease or similar agreement with the utility or third-party CSP owner that will install, repair, and maintain the CSP on the multifamily property.

Particular attention should be paid to the ability to terminate and/or assign subscription agreements, as there may be tension between CSP owners (and their financiers) concerned with the overall stability and integrity of the CSP portfolio and subscribers who may wish to terminate or assign their interest in the CSP. In addition, multifamily owners/developers must consider whether existing encumbrances on their property (e.g., easements, declarations, ground leases, zoning approvals, and/or mortgages and associated loan agreements) create prior approval rights or other barriers to installation. That review is most applicable for on-site CSPs, but it may also be relevant for building a CSP off-site or contracting with third-party CSP owners that provide the solar energy from off-site. Moreover, to the extent that a multifamily project is part of a joint venture seeking to capitalize on tax credit structures, a property owner should engage in a careful review of the operating and partnership agreements controlling what can and cannot be done by the property-owning entity, and the property owner should consult its own tax counsel. Finally, given that multifamily projects are residential in nature, a review should be conducted as to residential leasing laws to make sure that subscription agreements or other flow-down benefits to tenants do not run afoul of laws in the state where the property is located.

Moving away from contract-specific issues, there are also legal issues associated with locating CSPs. While it is true that CSPs may be located anywhere with sufficient solar resources, there are issues that can arise with the siting and permitting of these projects. One unique issue is the fact that many states include in their CSP-enabling legislation a requirement that CSPs be located within a certain distance from their subscribers. This limitation can result in competition for suitable sites within acceptable proximity to the customer base, which, in turn, can result in lengthy permitting delays. Additionally, CSP developers must be aware of local zoning restrictions and keep in mind that zoning authorities may not allow CSPs to be sited on agricultural or other specific types of land.

B. Regulatory Issues

There are some fairly broad regulatory issues that potential CSP owners/developers should be aware of. First and foremost, community solar is largely a creature of state policy. As such, the CSP model may not be viable in states which have not passed enabling legislation. For example, not all states allow for virtual net metering—a policy that must be implemented in a deregulated market or expressly enacted through state legislation. In states that lack the ability to virtually net meter, CSP developers may find it difficult to locate investors or subscribers for the program because they will be unable to receive any bill credits from an off-site generating facility. As of 2022, 22 states and the District of Columbia have passed some form of community solar enabling legislation. *See* U.S. EPA, Shared Renewables, *Shared Renewables*.

Second, many states that do have enabling legislation for CSPs set program and project caps for community solar. Specifically, as of May 2022, at least 19 states and Washington, D.C., included caps on their community solar programs. *See* Jenny Heeter, et al., Nat'l Renewable Energy Lab., *Status of State Community Solar Program Caps*. Most program caps are capacity-based and limit the number of CSPs in the state to a certain number of MWs produced. For example, Maryland currently has a program cap set at 583 MW or approximately 1.5% of the state's peak demand. *See id.* at 15-16. Most states with enabling legislation also set a cap on the capacity of individual CSPs (ranging from anywhere between 1 MW to 5 MW). It is important for potential CSP developers to check the status of varying program or project caps for the state in which the project will be located. A CSP may not be feasible if the state is close to capacity under its program cap or if the project cap limits the usefulness of the contemplated CSP.

Third, all CSPs need to be interconnected to the local utility grid and obtain utility approval for net metering through an interconnection agreement. Interconnection costs can be unique to each property, and the policies and application process for interconnection can vary widely from state to state, with lead times being lengthy. Additionally, many CSPs seek locations that are both suitable for solar development and close to potential customers. This combination of high demand and long lead times for interconnection can result in significant project delays if the relevant state has not adopted policies prioritizing the interconnection of CSPs.

Finally, CSP developers will need to be careful to design their project in a way that avoids subjecting it to regulation by the Securities and Exchange Commission (SEC). In *SEC v. W.J. Howey Co.*, the Supreme Court set forth the current test for determining if an offering constitutes a security and, therefore, must be registered with the SEC. 328 U.S. 293 (1946). The Howey test states that an offering constitutes a security when the buyer (a) invests their money (b) in a common enterprise (c) regarding which he has been led to expect profits, and (d) which will accrue "solely from the efforts of a promoter or a third party." Id. at 298-299. While the offering of a subscription to a CSP may arguably trigger its consideration as a "security" under the *Howey* test, the SEC has issued a No-Action Letter to a CSP developer reasoning that the subscribers to a CSP have no expectation of profit, but rather were purchasing a system for generating electricity for their own personal use. *See* Office of the Chief Counsel Division of Corporation Finance Securities and Exchange Commission, *Re: CommunitySun*, LLC . Nonetheless, it is important for any CSP developer to structure and market their program in a way that makes it clear subscribers are not profiting from an "investment" through the CSP, but only receiving electricity for personal use.

IV. Conclusion

Stated succinctly, community solar is a burgeoning opportunity for owners and developers of multifamily housing projects to provide lasting, positive impact on the environment and communities served, while also creating substantial economic benefits. To be sure, there are significant regulatory barriers in some jurisdictions and important legal considerations to weigh, but many of those issues can be overcome through careful and deliberate planning, research, and advocacy.

DIVERSITY, EQUITY & INCLUSION HIGHLIGHT

Join us in person in Houston, Texas on the afternoon of April 27th for Focus on Leadership: Embracing Authenticity, Overcoming Obstacles, and finding Success – a diversity, equity and inclusion and professional development program presented by the Institute for Energy Law.

This program is free and brings together professional development coaches and legal professionals for an afternoon of interactive sessions featuring timely topics.

This half-day conference immediately follows the conclusion of IEL's 2nd Conference on Renewables Project Development. Both programs will be held at the Norris Conference Center (Houston CityCentre) in Houston, Texas.

A Message from IEL

Submissions are open for the June issue of the Energy Law Advisor – Deadline to submit is May 29, 2023. The ELA welcomes submissions of member news, industry updates, case comments, signature pieces, and featured student articles for consideration. Submissions must be in word format and conform with other ELA guidelines.

Thank you to those who volunteered to be IEL publications liaisons – this issue has been a great success and we appreciate your support!

If you are interested in being your firm or company's publication liaison to IEL, please contact Kelly Ransom (kelly.ransom@kellyhart.com) and Emma Espey (eespey@cailaw.org).

MEMBERS IN THE NEWS

David E. Sharp of the law Offices of David E. Sharp P.L.L.C. has been elected chair of the North America Branch of the Chartered Institute of Arbitrators. David is a Fellow in the Chartered Institute and is based in Houston, Texas.

Tom Donaho, Energy Partner at BakerHostetler and IEL Member, published CCUS Regulatory Handbook, a practitioner's guide on CCUS regulatory issues.

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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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