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Editor's Note

One of the great advantages of publishing remarks from the President of the Energy & Mineral Law Foundation Board of Trustees at the beginning of each volume of the Energy & Mineral Law Institute Annual Proceedings is that they act as a historical record of the year in the history of the foundation, documenting its challenges and successes. Over the last two years, I have revisited these remarks on many occasions to find inspiration from the passion each of our previous presidents has felt for the organization, and comfort in the knowledge that EMLF has weathered hard times before and come out stronger than ever. It is in this spirit that I add these remarks to the historical record.

In March of 2020, as we were eagerly planning the 41st Annual Institute to be held in Amelia Island, Florida, the rapid spread of the newly discovered virus COVID-19 caused shutdowns throughout the country, closing retail stores and restaurants, restricting travel and gathering, and sending office workers online. EMLF members learned to use Zoom and Microsoft Teams, and both worked and socialized online from their homes. Needless to say, every conference we had planned for 2020 was either postponed or pivoted to a virtual format, and due to the unique circumstances, we were not able to publish an academic volume in 2020.

Though we were proud of the webinars and virtual conferences we presented — notably, the 41st Annual Institute and Fall Symposium and Safety Seminar held virtually in October of 2020, the Special Institute on Solar Power held virtually in January of 2021, and the Oil and Gas Environmental and Regulatory Institute held virtually in February of 2021 — we were so happy to be able to hold the 42nd Annual Institute in person in Memphis, Tennessee in June of 2021.

This volume represents scholarship from the 42nd Annual Institute, as well as other conferences held virtually during the COVID-19 pandemic, and represents the 41st and 42nd volumes of the Energy & Mineral Law Institute. Though, at the time of this publication, the COVID-19 pandemic continues to persist and impact the Foundation and our individual lives, we remain hopeful and optimistic as we look to a new chapter.

I would be remiss if I did not say a word of thanks, and record here the efforts of our pandemic-time presidents, Timothy J. Hagerty and Kevin L. Colosimo, whose unwavering leadership and counsel have ensured that EMLF has continued to thrive during this difficult period. A second note

of appreciation is in order for our 2020 and 2021 program chairs, Karen J. Greenwell, Robert L. McLusky, and Anthony J. Giuliani, I. Bobby Majumder, and Stephanie L. Burt, who endured uncertainty, postponements, and format changes to oversee successful conferences.

And finally, a thank you to our members, patrons, and sponsors for your flexibility and support as we navigated the roadblocks of 2020 and 2021.

Anna Girard Fletcher
Editor-in-Chief, Energy & Mineral Law Institute
Executive Director, Energy & Mineral Law Foundation

Preface

Kevin L. Colosimo
EMLF President 2020-2021

Thank you for your support, participation, and most of all your attendance at our 42nd Annual Institute. Given the challenges of the last year brought on by the pandemic, we saw returning to live programming for this year's Annual Institute as both a challenge and an opportunity.

Travel restrictions, vaccination, and virus protocols, not to mention childcare and family obligations were foremost on our minds as we made the decision to forge ahead for our first ever visit to Memphis. At the same time, we heard our members' voices asking for live programing and yearning for the opportunity to meet and discuss pressing and dynamic issue in Energy Law, as well as visit colleagues old and new.

The 2021 Annual Institute Programming Committee coalesced around the thoughtful leadership of Co-Chairs Stefanie Burt and I. Bobby Majumder. Stefanie and Bobby recognized the importance of providing timely and insightful programming to the energy law community in a time of uncertainty and change.

A new administration and regulatory regime in Washington, D.C. focused on climate change, emphasis on renewable energy sources, de-carbonization and ongoing challenges to fossil fuels, the failure of the power grid following climactic aberration in Texas, and the ongoing challenges facing the energy community in wake of Covid-19 were just some of the topics front and center at this year's Annual Institute. And, I'm proud to say that our lineup of speakers and presenters was as diverse and inclusive as the topics they represented.

A word of thanks to a long-time friend and supporter of EMLF and this year's Keynote Speaker, Charles Patton, EVP of American Electric Power, for his sage wisdom and keen insight into the ever-changing energy landscape one last time as he sails toward a well-deserved retirement. Godspeed Charles.

Most importantly, we gathered in Memphis to fulfill our mission of scholarship. This year, despite the financial challenges of Covid-era, the EMLF awarded $30,000 in scholarships to 11 well-deserving law students at six law schools. Many of those scholarship recipients, along with some of their peers and recent law school graduates, joined us in Memphis, without

cost, through the lasting legacy of the Russ Schetroma Scholarship Fund. I would be remiss not to mention the tireless work of the Scholarship Committee and the fiscal responsibility and discipline of past EMLF leadership, whose forethought carried EMLF through a difficult financial period.

Finally, we recognize our dear friend and colleague Erin Magee with our highest honor — the John L. McClaugherty Award. Erin represents the finest among us, and her willingness to serve the EMLF and the energy industry community is unyielding. Thank you Erin for your passion and dedication.

As my presidency winds to a conclusion, I am grateful for many individuals who come together in leadership of the EMLF — its officers and executive committee, trustees and committee members, and certainly its fine staff under the leadership of Executive Director Anna Girard Fletcher.

I am grateful to all those who rose to the occasion during this tumultuous time, presenting webinars, providing written content, organizing conferences, sharing ideas, mentoring law students, and always working for the betterment of the energy law community. I am grateful and thankful for our patrons and sponsors, without whom EMLF could not survive.

My thanks to my firm, Frost Brown Todd, for encouraging and supporting my involvement in EMLF. I am grateful to Sheila Nolan Gartland, whom I've worked alongside at EMLF for so many years and into whose trusted and capable hands I pass the gavel of leadership. Finally, I'm grateful to each and every member of this fine organization; I am so proud and honored to call you my colleagues.

Chapter 1

Practicing Ethically Online and On Air: The Intersection of Media and Legal Ethics

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Synopsis

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§ 1.01. Introduction.

Part of ethical representation may involve representing clients in the media — responding to journalists and television reporters, either online, in print, or on air. Rule 1.4(a)(2) of the ABA Model Rules of Professional Conduct requires a lawyer to "reasonably consult with the client about the means by which the client's objectives are to be accomplished." This can include a detailed media plan. Sophisticated clients may be reasonably reluctant to have attorneys speak on their behalf, having employed or trained professionals for this specific purposes in mind. Attorneys may also be just as reasonably reluctant to make public statements. Nonetheless, there is always the possibility that an exciting or unusual issue — or controversial client — will pique attention and the next phone call or email might be from a journalist looking for answers. Attorneys should be prepared in advance for that call or email and understand both client expectations and the ethical limitations on what can or should be said.

Attorneys may consider themselves as acting entirely outside of the public eye and not requiring training on media relations. But it is always possible that a fraught motion hearing will attract public notice — and extremely likely that a firm marketing department might want to share information on recent successes on a website or email. A comfortable grasp of the ethical limitations on what one can and cannot do on the phone, on a microphone or online should be maintained and sometimes refreshed.

The rules that are most commonly implicated by attorney interactions with media include Model Rules of Professional Conduct 1.6 and 3.6.[1] These rules control interactions between attorneys and traditional journalists as well as attorneys posting updates and accomplishments online.

§ 1.02. Ethically Speaking to the Media on Behalf of Your Client While Protecting Confidentiality.

Rule 1.6 controls the confidentiality and the release of client information by the attorney:

Client-Lawyer Relationship

(a) A lawyer shall not reveal information relating to the representation of a client unless the client gives informed consent, the disclosure is impliedly authorized in order to carry out the representation or the disclosure is permitted by paragraph (b).

(b) A lawyer may reveal information relating to the representation of a client to the extent the lawyer reasonably believes necessary:

(1) to prevent reasonably certain death or substantial bodily harm;

(2) to prevent the client from committing a crime or fraud that is reasonably certain to result in substantial injury to the financial interests or property of another and in furtherance of which the client has used or is using the lawyer's services;

(3) to prevent, mitigate or rectify substantial injury to the financial interests or property of another that is reasonably certain to result or has resulted from the client's commission of a crime or fraud in furtherance of which the client has used the lawyer's services;

(4) to secure legal advice about the lawyer's compliance with these Rules;

(5) to establish a claim or defense on behalf of the lawyer in a controversy between the lawyer and the client, to establish

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1 Model Rules of Prof'l Conduct r. 1.6, 3.6. The ABA's Model Rules of Professional Conduct are available online here: https://www.americanbar.org/groups/professional_responsibility/publications/model_rules_of_professional_conduct/model_rules_of_professional_conduct_table_of_contents/. Almost all states have adopted these rules, although there are some minor variations and additions. For example, Florida is contemplating an addendum to these rules, as will be further discussed below.

a defense to a criminal charge or civil claim against the lawyer based upon conduct in which the client was involved, or to respond to allegations in any proceeding concerning the lawyer's representation of the client;

(6) to comply with other law or a court order; or

(7) to detect and resolve conflicts of interest arising from the lawyer's change of employment or from changes in the composition or ownership of a firm, but only if the revealed information would not compromise the attorney-client privilege or otherwise prejudice the client.

(c) A lawyer shall make reasonable efforts to prevent the inadvertent or unauthorized disclosure of, or unauthorized access to, information relating to the representation of a client.[2]

In short, part (a) tells us what we have to keep confidential; (b) tells us what we do not have to keep confidential, and (c) tells us how hard we have to try to keep things confidential.

Part (c) is especially interesting at this time because the understanding of what is "reasonable" effort to prevent access to information is constantly changing. For example, the ABA recently indicated that it may no longer consider the use of unencrypted email to be "reasonable" by attorneys, although it stopped short of saying that encrypted email must be adopted as standard.[3] This was a change from a previous opinion in which the ABA said that the use of email was in fact reasonably protective of confidentiality.[4] With the rise of ransomware attacks and spyware, the understanding of how vigilant an attorney must be is evolving.

The ABA has focused in on lawyer and law firm blogs (as well as social media accounts) as a potential source of lapses in confidentiality, issuing a 2018 "Formal Opinion 480" entitled "Confidentiality Obligations for Lawyer Blogging and Other Public Commentary."[5] This is a fairly stern opinion, limiting much of what a lawyer might otherwise mention in an innocuous

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2 Model Rules of Prof'l Conduct r. 1.6.

3 ABA Comm. On Ethics & Prof'l Responsibility, Formal Op. 447 (2017) (noting that "it is not always reasonable to reply on the use of unencrypted email.").

4 ABA Comm. On Ethics & Prof'l Responsibility, Formal Opinion 99-413 (1999).

5 ABA Comm. On Ethics & Prof'l Responsibility, Formal Opinion 480 (2018).

firm social media update or newsletter. Formal Opinion 480 says that a lawyer's duty of confidentiality is broad and covers all information related to the representation, not just information learned from the client. That prohibition is quite broad and likely misunderstood by most: ALL information related to the representation falls under the purview of Rule 1.6. This applies even if the information about the client's representation is found in a court record or other public record. A client can give consent to discuss the public-facing aspects of their case under (a), but without that consent, even public information about the overall case and its progress cannot be disclosed by the lawyer to anyone: "The duty of confidentiality extends generally to information related to a representation whatever its source and without regard to the fact that others may be aware of or have access to such knowledge."[6]

Formal Opinion 480 goes on to note that the "salient point is that when a lawyer participates in public commentary that includes client information, if the lawyer has not secured the client's informed consent or the disclosure is not otherwise impliedly authorized to carry out the representation, then the lawyer violates Rule 1.6(a)." The Opinion acknowledges what it terms "First Amendment considerations," but emphasizes that free speech rights are often limited when lawyers act in their representational capacities.[7]

While this is "just" a Formal Opinion from an ABA committee, and lacking binding authority, it nonetheless does reflect actual ethics practice throughout the country. For example, in Illinois, an attorney was suspended for five months by the state bar when he posted a video clip on Youtube that he felt exonerated his client.[8] He had obtained the video through the discovery process. The governing state body, the Illinois Attorney Registration and Disciplinary Commission, found that the attorney had failed to obtain informed consent from his client in violation of Rule 1.6(a) to post the video. The attorney went on to sue the Commission in federal court, but lost when

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6 *Id*.

7 *Id*.

8 Jana Hanna, *Lawyer sues after his YouTube post of client leads to suspension*, Illinois bar journal (May 2014), https://www.isba.org/ibj/2014/05/lawpulse/lawyersuesafterhisyoutubepostofclie

the federal court stated that his suit was an attempt to "obtain collateral review of an ARDC decision in federal district court."[9]

In Massachusetts, a lawyer was reprimanded when he posted about an ongoing case on his Facebook page. This was not an attempt to brag about results, but rather a run-of-the-mill update about the attorney's day: "I am back in the Boston office after appearing in Berkshire Juvenile Court in Pittsfield on behalf of a grandmother who was seeking guardianship of her 6 year old grandson . . . ."[10] The client was told about the post (and ensuing comments) and complained about it to the state disciplinary board. Considering the lack of identifying information on the post, one might think the board was understanding about the lapse. One, however, would be wrong. The Board was extremely uncompromising in its opinion, pointing out that "Even if there were no evidence that a third party actually recognized the client in the post, we would still conclude that the respondent had violated Rule 1.6(a). There is no requirement that a third party actually connect the dots."[11] Rather, the Board ruled, it is a rules violation if it is "reasonably likely that a third party could do so."[12]

Worse for this Massachusetts attorney, he pled that he had been a long-standing member of the Bar without any prior disciplinary actions, and the Board responded by noting that, "He is an experienced attorney. He should understand the importance of protecting client confidences . . . his experience should have caused him to proceed with extreme caution before disclosing any information about his client's case . . . In addition, social media is not new. Facebook was established in 2006. It (along with other social media such as Twitter, Instagram and LinkedIn) are part of the everyday lives of most

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9 Gilsdorf v. Att'y Registration and Disciplinary Comm'n of Supreme Ct. of Illinois, No. 13-CV-3405, 2014 WL 3495734, at *3 (C.D. Ill. July 14, 2014)

10 Karen Rubin, *Facebook posts that revealed client info bring public reprimand for MA lawyer*, The Law for Lawyers Today (Nov. 21, 2019), https://www.thelawforlawyerstoday.com/2019/11/4684/

11 Board Memorandum, Bar Counsel v. Frank Arthur Smith III, Commonwealth of MA Board of Bar Overseers of the Supreme Judicial Court, No. 16-2019 (available at https://bbopublic.blob.core.windows.net/web/f/pr19-16.pdf).

12 *Id*. at 7.

Americans. . . . Having chosen to use Facebook, the respondent was required to follow the rules for maintaining client confidences on its platform."[13]

But we can contrast these results in Illinois and Massachusetts with two others — from Virginia and Colorado respectively. In Virginia, an attorney was initially sanctioned for writing blog posts on his firm's website detailing cases he had won. In one of these, he wrote about obtaining a positive outcome for his client even though his client's failed drug test had come up in the court proceeding. The Virginia disciplinary board took issue with that revelation and suspended the attorney, but the Supreme Court overturned those sanctions: "The [Virginia State Bar] argues that it can prohibit an attorney from repeating truthful information made in a public judicial proceeding even though others can disseminate this information because an attorney repeating it could inhibit clients from freely communicating with their attorneys or because it would undermine public confidence in the legal profession. . . . To the extent that the information is aired in a public forum, privacy considerations must yield to First Amendment protections. In that respect, a lawyer is no more prohibited than any other citizen from reporting what transpired in the courtroom. Thus, the circuit court did not err in concluding that the VSB's interpretation of Rule 1.6 violated the First Amendment."[14]

And in Colorado, an attorney escaped consequences for ongoing online commentary and fundraising about her animal-rights-activism-related cases and clients. The Colorado Supreme Court noted that the attorney had obtained client consent to disclose information about the cases and their own financial condition and, moreover, "Respondent carefully timed most of her social media posts to keep one step behind the development of the public record."[15]

So, under Rule 1.6, we have outcomes that vary depending on whether the client consented to the disclosures made and whether the case itself was concluded. The opinions appear media-neutral, as these cases involved Facebook, Youtube, a lawfirm blog page, and GoFundMe pages, but the

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13 *Id*. at 10.

14 Hunter v. Virginia State Bar ex rel. Third Dist. Comm., 285 Va. 485, 503 (2013).

15 Opinion and Decision Imposing Sanctions Under CRCP 251.19(b), People v. Juliet R. Piccone, Supreme Court of Colorado Disciplinary Proceeding No, 19-PDJ041 (2019).

best outcomes for attorneys appear to result when the attorney faced with disciplinary charges can state that the client consented to the disclosure, the disclosure involves public information, *and* the proceeding is in the past.[16]

Another unfortunate aspect of practicing in today's online environment is the ubiquity of online reviews — often negative. This has become a major issue for attorneys — and state bars — struggling to face dishonest or emotionally charged reviews without disclosing any information, even public information, about the representation. The ABA's recent Formal Opinion 498 from 2021 is extremely strict in its view of how attorneys should respond to negative online reviews, possibly to an unrealistic extent.[17]

Formal Opinion 498 suggests that "[l]awyers should give serious consideration to not responding to negative online reviews in all situations. . . As a practical atter, no response may cause the post to move down in search result rankings and eventually disappear into the ether." This seems extremely unrealistic on its face and may reflect a lack of understanding how clients and the public tend to review attorneys. However, there is one other option offered; "Lawyers may respond with a request to take the conversation offline and to attempt to satisfy the person, if applicable. For example, a lawyer might post in response to a former client, 'Please contact me by telephone so that we can discuss your concerns.'"[18] One more option is provided: "An additional permissible response, including to a negative post by a client or a former client, would be to acknowledge that the lawyer's professional obligations do not permit the lawyer to respond. A sample response is: 'Professional obligations do not allow me to respond as I would wish.'"[19]

Per this opinion, almost no other statement is allowed by the ethical rules, particularly Rule 1.6. *"[T]he lawyer may not disclose any information relating to the client or former client's representation without the client or former client's informed consent*. Even a general disclaimer that the events

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16 For general advice on ethical practice across social media platforms, this book is an excellent resource: Jan L. Jacobwitz and John G. Browning, Legal Ethics and Social Media: A Practitioner's Handbook, 2017.

17 ABA Comm. On Ethics & Prof'l Responsibility, Formal Opinion 498 (Mar. 10, 2021).

18 *Id*.

19 *Id*.

are not accurately portrayed may reveal that the lawyer was involved in the events mentioned, which could disclose confidential client information."[20]

Recall that Rule 1.6 includes (b), the things that lawyers can lawfully reveal without violating confidentiality, and there is a "self-defense" exception to the general rule:

(5) to establish a claim or defense on behalf of the lawyer in a controversy between the lawyer and the client, to establish a defense to a criminal charge or civil claim against the lawyer based upon conduct in which the client was involved, or to respond to allegations in any proceeding concerning the lawyer's representation of the client.

However, the New York State Bar Association addressed this "self-defense" exception in relation to negative online reviews and determined that "negative web posting[s]" do not trigger the exception. Only claims and charges in formal proceedings, or a material threat of a proceeding — which typically means a lawsuit, criminal inquiry, disciplinary complaint, or similar procedure, and not a 1-star rant on Google.[21]

Interestingly, the Florida Professional Ethics Committee voted to approve a special exception to Rule 1.6 for online reviews, which would allow a lawyer to reveal confidential information to the extent a lawyer "reasonably believes" it is necessary to "respond to specific allegations published via the internet by a former client (e.g. a negative online review) that the lawyer has engaged in criminal conduct punishable by law."[22] This exception was approved by the Committee but does not appear to have been presented to the Board of Governors of the Florida Bar as of this writing.

§ 1.03. Ethical Trial Publicity.

The primary rule governing trial publicity ethics is found at Rule 3.6 of the Model Rules:

(a) A lawyer who is participating or has participated in the investigation or litigation of a matter shall not make an extrajudicial statement that

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20 *Id*. (emphasis added).

21 New York State Bar Association Ethics Opinion 1032 (10/20/14) (available at https://nysba.org/app/uploads/2014/10/Opn-1032.pdf).

22 Gary Blankenship, *PEC Tackles Knotty Issues of Responding to Online Criticism*, Florida Bar News (Mar. 25, 2021), https://www.floridabar.org/the-florida-bar-news/pec-tackles-knotty-issues-of-responding-to-online-criticism/

the lawyer knows or reasonably should know will be disseminated by means of public communication and will have a substantial likelihood of materially prejudicing an adjudicative proceeding in the matter.

(b) Notwithstanding paragraph (a), a lawyer may state:

(1) the claim, offense or defense involved and, except when prohibited by law, the identity of the persons involved;

(2) information contained in a public record;

(3) that an investigation of a matter is in progress;

(4) the scheduling or result of any step in litigation;

(5) a request for assistance in obtaining evidence and information necessary thereto;

(6) a warning of danger concerning the behavior of a person involved, when there is reason to believe that there exists the likelihood of substantial harm to an individual or to the public interest; and

(7) in a criminal case, in addition to subparagraphs (1) through (6):

(i) the identity, residence, occupation and family status of the accused;

(ii) if the accused has not been apprehended, information necessary to aid in apprehension of that person;

(iii) the fact, time and place of arrest; and

(iv) the identity of investigating and arresting officers or agencies and the length of the investigation.

(c) Notwithstanding paragraph (a), a lawyer may make a statement that a reasonable lawyer would believe is required to protect a client from the substantial undue prejudicial effect of recent publicity not initiated by the lawyer or the lawyer's client. A statement made pursuant to this paragraph shall be limited to such information as is necessary to mitigate the recent adverse publicity.

(d) No lawyer associated in a firm or government agency with a lawyer subject to paragraph (a) shall make a statement prohibited by paragraph (a).[23]

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23 Model Rules of Prof'l Conduct r. 3.6

Rule 3.6 follows a pattern much like Rule 1.6: part (a) sets out the general prohibition and part (b) gives a list of exceptions to the rule against speaking. Part (c) once again brings in "reasonableness" as the standard of behavior.

One lawyer who was sanctioned for trial publicity had filed a class action lawsuit against a grain processing company for its environmental performance. When he spoke to the media about his case, the attorney used unequivocal language:

> Mr. Buzbee told the press, "There is real, verified damage being to people's real and personal property. Ask anyone who lives in the area who every morning has to clean their car because it is covered in soot again. Go down there like I did last night and just look at the smoke billowing out of the facility where it lands. It barely goes above the stacks, moves to the right, crosses the road and starts to slowly permeate into the neighborhood. It is pretty drastic." . . . He also told the press, "He filed the lawsuit after recent testing at homes and public parks revealed dangerously high levels of acetaldehyde and sulfuric acid, among other substances." Two days later, Mr. Buzbee told the press, "Initially we are seeking to speed up this process of cleaning up the air and changing their procedures in order to do business. Ultimately, we seek remediation of the homes and we want to put the homes back in the condition they would have been in but for GPC's conduct." . . . he also stated, "They release several kinds of chemicals and some of these chemicals are very corrosive and so any metal components in their homes, including things like nails, any metals on the outside of their homes, air conditioning ducts, any kind of metal component, this corrosion is accelerated.[24]

The attorney was sanctioned for these statements and his pro hac vice status in the state was revoked as a consequence. "The Court finds Buzbee violated the rule by making the statements he did in the press. The statements assert a foregone conclusion that potential plaintiffs have suffered real, verified damage, an issue contested in the litigation. This kind of statement do

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24 Freeman v. Grain Processing Corp., No. LACV021232, 2012 WL 13140726, at *1 (Iowa Dist. July 09, 2012).

not advance the public's right to have knowledge about the proceedings, but rather taint the jury pool and damage the defendant's right to a fair trial."[25]

In a way it is surprising that the Iowa court judged these statements so harshly, given Rule 3.6(b)'s list of permissible exceptions. One could plausibly argue that his statements to the media involved information contained in a public record (exception 2), included a statement that an investigation of a matter is in progress (exception 3), requested assistance from the public in obtaining evidence (exception 5), and/or warned of the danger from the facility in question (exception 6). However, it appears that it was the unequivocal nature of his comments that irked the court. Had he prefaced these comments with claims like "We allege that . . . ," and "We believe and intend to prove that…" it is possible that he would have not faced the same penalty.

Part (c) provides an interesting footnote to the rule, as it allows an attorney to rebut rumors and public statements by opponents in order to protect a client from substantial undue prejudice.[26] This "defense of client" provision was added in 1994 and to date, appears not to have been tested in any published disciplinary proceedings. There are limitations to the application of the rule: the attorney defending her client to the press must be "reasonable" in her belief that her statements are necessary to protect her client from "undue" prejudice. But apparently the rule has been generally followed by attorneys when called upon to respond to attacks in the press on their clients.

One aspect of trial publicity is being able to speak to the media, as permitted by 3.6(b) and (c), while understanding how the media will reflect and respond to your words. Knowing, for example, the rules of press attribution can be a key part of an ethical practice under Rules 1.1 (competence), 1.4(a)(2) (the means by which a client's objectives are to be accomplished), and of course Rules 1.6 (confidentiality of client information) and 3.6 (trial publicity limitations). There are numerous guides and media trainings available for attorneys and if your practice appears to involve speaking to the press on

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25 *Id*. at *2 (citing Iowa Supreme Court Bd. of Professional Ethics and Conduct v. Visser, 629 N.W.2d 376, 381 (Iowa 2001) (holding that statements reasonably likely to affect the fairness of the proceedings violate Iowa's Rules of Professional Conduct).

26 Model Rules of Prof'l Conduct r. 3.6.

occasion, it may need to be part of your ethical representation of clients to study the rules and practices of journalism.[27]

Another risk of trial publicity, outside of the realm of legal ethics, is defamation. Although lawyers are protected from civil suits for things they say in the courtroom, "that same protection does not apply to interviews to the press on the courthouse steps. Lawyers can face suits for slander for comments to the media."[28] For example, in the wake of the 2020 election and the dozens of federal lawsuits filed around the country by the group of attorneys known as the "Kraken," along with the subsequent dismissals of those suits, one of the major defendants, Dominion Voting Systems Corporation, has filed suit against the Kraken attorneys alleging defamation.[29] The suit claims that defamatory statements were made in the course of the litigation against Dominion when various Kraken members spoke to members of the press.[30]

The defendants filed a motion to dismiss and Dominion opposed, arguing that statements in any media were potentially subject to a defamation action and citing various cases in support that each provide examples of attorney attempts at trial publicity gone wrong:

> First, a law license is not a license to lie, and courts routinely permit defamation actions to proceed against attorneys based on statements made outside the courtroom—even when those statements relate to litigation. *See, e.g., Sang v. Hai*, 951 F. Supp. 2d 504 (S.D.N.Y. 2013) (lawyer's statements at a press conference and on his blog were not

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[27] Gina F. Rubel, Everyday Public Relations for Lawyers (2nd ed. 2019), is a good resource for attorneys facing the media regularly, although this book primarily covers marketing one's services. Shorter articles with helpful information on common practices, the rules of attribution, and other advice for lawyers include: Lisa Meyer, *A Public Relations Plan for Lawyers Demands a Multi-Layered Approach*, 24 Maine B.J. 196 (2009); Jack B. Zimmerman, *Representing High-Profile Clients the Ethical Way*, 67 Tex. B.J. 772 (2004); and Scott H. Segal and Ricardo Reyes, *Masks and Mystification: The Challenges of Media Relations and Public Relations for Lawyers*, 67 Tex. B.J. 752 (2004).

[28] H. Morley Swingle, *Warning: Pretrial Publicity May Be Hazardous to Your Bar License*, 50 J. Mo. B. 335, 338 (1994).

[29] US Dominion, Inc., et al. v. Sidney Powell et al., Civil Action No. 1:21-cv-0040-CJN, D.D.C. (2020).

[30] *See* Defendants' Motion to Dismiss, Dkt. No. 22, filed 3/22/21, US Dominion, Inc., et al. v. Sidney Powell et al., Civil Action No. 1:21-cv-0040-CJN, D.D.C. (2020).

privileged); *3P-733, LLC v. Davis*, 187 A.D.3d 626, 629 (N.Y. App. Div. 2020) (reversing dismissal of defamation claims based on pre-litigation letter because the letter was disseminated to a third party that was not directly involved in the underlying dispute); *Seidl v. Greentree Mortg. Co.*, 30 F. Supp. 2d 1292, 1315 (D. Colo. 1998) ("an attorney who wishes to litigate her case in the press and via the Internet does so at her own risk. There is no absolute privilege under Colorado law for statements by an attorney or by a party made to the press or gratuitous statements posted on the Internet for the purpose of publicizing the case to persons who have no connection to the proceeding except as potentially interested observers.") . . .[31]

The Dominion v. Kraken defamation suit is still proceeding as of this writing, but has provided a fascinating look into the briefing on both sides of a defamation-for-trial-publicity claim.

§ 1.04. Misconduct for Misconduct's Sake: Rule 8.4.

Rule 8.4 is sometimes invoked by courts and disciplinary bodies when attorneys' bad behavior is unconnected to the representation of a client and thus does not necessarily trigger sanctions under other rules. As the rule broadly states:

It is professional misconduct for a lawyer to:

(a) violate or attempt to violate the Rules of Professional Conduct, knowingly assist or induce another to do so, or do so through the acts of another;

(b) commit a criminal act that reflects adversely on the lawyer's honesty, trustworthiness or fitness as a lawyer in other respects;

(c) engage in conduct involving dishonesty, fraud, deceit or misrepresentation;

(d) engage in conduct that is prejudicial to the administration of justice;

(e) state or imply an ability to influence improperly a government agency or official or to achieve results by means that violate the Rules of Professional Conduct or other law;

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[31] Dominion's Opposition to Defendants' Motion to Dismiss, Dkt. No. 39, filed 5/3/21, US Dominion, Inc., et al. v. Sidney Powell et al., Civil Action No. 1:21-cv-0040-CJN, D.D.C. (2020).

(f) knowingly assist a judge or judicial officer in conduct that is a violation of applicable rules of judicial conduct or other law; or

(g) engage in conduct that the lawyer knows or reasonably should know is harassment or discrimination on the basis of race, sex, religion, national origin, ethnicity, disability, age, sexual orientation, gender identity, marital status or socioeconomic status in conduct related to the practice of law. This paragraph does not limit the ability of a lawyer to accept, decline or withdraw from a representation in accordance with Rule 1.16. This paragraph does not preclude legitimate advice or advocacy consistent with these Rules.[32]

Sometimes, as the above-referenced media guides note, attorneys are called upon to opine generally on legal issues or specific cases of interest to the media. Rule 8.4 should be familiar to any such attorney, as it limits how far we can speculate when serving as general subject-matter resources or experts for journalists or when writing on our own behalf.

Often, sadly, rule 8.4 is invoked against lawyers whose own personal domestic matters affect their judgment and result in angry social media posts about opposing counsel or judges.[33]

However, it can also reach more broadly, as a Tennessee attorney recently discovered when he was suspended for online comments on a friend's Facebook post in which the attorney provided advice about how to kill without facing legal consequences: "If you do want to kill him, then lure him into your house and claim he broke in with intent to do you bodily harm and that you feared for your life. Even with the new stand your ground law, the castle doctrine is a far safer basis for use of deadly force. . . . As a lawyer I advise you to keep mum about this if you are remotely serious. Delete this thread and keep quiet."[34] This attorney was found to have violated Rule 8.4 with this advice and suspended for four years.[35]

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32 Model Rules of Prof'l Conduct r. 8.4.

33 *See, e.g.*, Florida Bar v. Sayler, 721 So.2d 1152 (Fla. 1998); In re McCool, 172 So. 3d 1058 (2015).

34 In re Winston Brandshaw Sitton, Supreme Court of Tennessee, No. M2020-00401-SC-BAR-BP (1/22/2021) (available at https://www.tncourts.gov/sites/default/files/in_rewinstonbranshawsitton.opn_.pdf)

35 *Id*.

The Tennessee Supreme Court's lengthy opinion in this issue provides an excellent summary to the overall issues with lawyers participating in our online society:

> [T]here is nothing wrong with lawyers participating in social media. Indeed, much good can come of it. Lawyers can establish an online presence, engage in their communities, show their personalities and interests outside the law, develop relationships on social-media platforms, and market their legal services. Lawyers participating in social media can do much to demystify the legal system.
>
> Nevertheless, attorneys in any setting — including on social media platforms — remain bound by our Rules of Professional Conduct. . . . *Lawyers who choose to post on social media must realize they are handling live ammunition; doing so requires care and judgment*. Social media posts are widely disseminated, and the damage from a single ill-advised comment is compounded and magnified.
>
> The fact that ethically problematic conduct occurs on a social media platform need not always be an aggravating circumstance. However, if the use of social media exacerbates the problem the ethics rule seeks to address, we hold that it may be considered an aggravating factor for purposes of lawyer discipline. Here, *Mr. Sitton's choice to post his comments on a public platform amplified their deleterious effect. . . . the public venue for Mr. Sitton's bad advice created a risk that others would use it as well*.[36]

§ 1.05. Conclusion.

The job of the attorney is that of counselor, advocate and, sometimes, spokesperson. It is in this latter role that we may encounter members of the media or public asking for our thoughts, opinions and reactions, or we may simply want to volunteer them as part of our firm's marketing. We can do all of these things, and we can do so ethically and responsibly, if we pay attention to and actually use and apply the Rules of Professional Conduct in limiting what we say and when we say it. Client consent and protecting client confidences are paramount but should not prevent the successful use of media by counsel.

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36 *Id*. at pp. 22-23.

Chapter 2

A Discussion of Current Pipeline Litigation, Land Rights, FERC Matters, Future Projections, and More

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§ 2.01. Introduction.

This chapter and presentation discuss the current state of pipeline litigation nationwide, including the impacts of COVID-19 on the pipeline industry, ongoing and new developments impacting land rights, developments with the Federal Energy Regulatory Commission ("FERC"), future

projections for the pipeline industry, and more. Environmental activism is on the rise, affecting pipeline projects and litigation nationwide. The COVID-19 pandemic has also had a profound impact on all industries, oil and gas pipelines included. In addition, the rise in cyber attacks has had a profound impact in the past year.

§ 2.02. Recent Events.

[1] — COVID-19.

The COVID-19 pandemic has demonstrated a significant disruption to oil and gas demand. The sudden transition to a "stay at home" work economy last year resulted in a steep drop in demand for gasoline, jet fuel, and like products. Prices for oil plummeted. At one point, on April 20, 2020, WTI crude contracts for May 2020 dropped 306% to negative $37.63 per barrel. This enormous disruption in demand and resulting price decreases resulted in a glut of oil that persisted through much of 2020. Subsequently, the price of oil recovered. Fluctuations of this sort show that in a greening energy market, oil and gas are still relevant. Thus, the pipelines that carry those fuels are still relevant and critical to infrastructure.

[2] — Keystone XL Cancellation.

The Keystone XL pipeline has been a hot button political issue for years. The planned oil pipeline was to be 1,179 miles long, stretching from the Canada to Texas. It was designed and intended to carry Canadian oil sands to United States refineries for processing. The project itself endured years of challenges: political, litigation, and otherwise.

The pipeline faced intense opposition from Native American and First Nations groups in both the United States and Canada, as well as from environmental groups. In the United States, the Rosebud Sioux Tribe and Fort Belknap Indian Community sued to stop the pipeline, alleging violations of administrative processes, including environmental, tribal hunting and fishing rights, and the pipeline's impact on cultural sites.[1] Following years of back-and-forth regarding permitting of the pipeline, then-President Trump

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1 Rosebud Sioux Tribe v. Trump, No. 4:18-cv-00118, 495 F. Supp. 3d 968 (D. Mont. 2020).

issued a cross-border permit in March of 2019 allowing the pipeline to move forward and cross the Canadian border. Upon his inauguration into office, President Biden revoked the permit by executive order.[2]

On March 17, 2021, 21 states filed a lawsuit in the Southern District of Texas[3] challenging President Biden's order cancelling the permit. The lawsuit claims a violation of the separation of powers doctrine, alleging that President Biden could not have revoked the permit because Congress had granted the permit previously by operation of law, as well as a violation of the non-delegation doctrine.

Following this legal wrangling, TC Energy Corp. elected to cancel Keystone XL in June of 2021. The cancellation of the project may moot the litigation challenging President Biden's cancellation of the cross-border permit, but to date, the lawsuit is still pending in federal court.

[3] — Atlantic Coast Pipeline Cancellation.

The Atlantic Coast Pipeline took a similar, but shorter, path toward cancellation. The Atlantic Coast Pipeline was announced in 2014. FERC issued a certificate of public convenience and necessity authorizing the project on October 13, 2017. Atlantic acquired by negotiations roughly 98-99% of the land rights needed for the 600-mile pipeline. This pipeline faced tremendous environmental opposition, with multiple legal challenges filed to permits, culminating in a Supreme Court case, which was decided in favor of allowing the pipeline to continue.[4]

In *United States Forest Serv. v. Cowpasture River Pres. Ass'n*, a coalition of environmental groups appealed the issuance of a permit from the United States Forest Service that allowed the pipeline to cross the Appalachian Trial. The appellants were successful in the Fourth Circuit, which held that the Forest Service: (1) failed to analyze whether the substantive requirements of the 2012 Forest Planning Rule were related to the forest plan amendments; (2)

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2 Exec. Order No. 13990, 86 Fed. Reg. 7037 (Jan. 20, 2021).

3 State of Texas, et al. v. Joseph R. Biden, Jr., et al., No. 3:21-cv-00065, (S.D. Tex.) (filed Mar. 17, 2021).

4 United States Forest Serv. v. Cowpasture River Pres. Ass'n, 140 S. Ct. 1837, 1839 (2020).

the Forest Service's finding that the amendments would not have substantial adverse effects was arbitrary and capricious; (3) failed to independently review the FERC's environmental impact statement before adopting it; and (4) lacked authority to grant a right of way across the Appalachian Trail, which was part of the National Park System.[5] On appeal to the Supreme Court, the Court held that: (1) the National Trails System Act did not transfer jurisdiction of the lands crossed by the Appalachian Trail from the United States Forest Service to the Department of the Interior, rather it created a trail easement and gave the Department of the Interior the administrative responsibilities concomitant with administering the Trail as a trail; and (2) because the Department of the Interior had no jurisdiction over any lands, its delegation to the National Park Service did not convert the Trail into lands in the National Park System for purposes of the Mineral Leasing Act, 30 U.S.C.S. § 185(b)(1), thus the Forest Service retained the authority to grant a natural gas pipeline right-of-way under the Trail.[6]

Despite the Supreme Court's decision validating a permit for the crossing of the Appalachian Trail on June 15, 2020, Atlantic elected to cancel the project entirely on July 5, 2020, citing ballooning costs.

As required under the circumstances, Atlantic sought approval from FERC to abandon the project. On July 10, 2020, Atlantic notified FERC of the project's cancellation and requested additional time to complete any work required for restoration and abandonment.[7] Atlantic took several months to compile its plan to wind down the pipeline project. Atlantic submitted its disposition and restoration plan dated December 16, 2020. FERC then issued a Notice of Amendment of Certificates and Opening of Scoping Period and a Notice of Intent to Prepare a Supplemental Environmental Impact Statement and Notice of Schedule for Environmental Review.[8] This outlines FERC's schedule for reviewing the wind down plan from Atlantic and also initiates a new environmental review process,

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5 Cowpasture River Pres. Ass'n v. Forest Serv., 911 F.3d 150 (4th Cir. 2018).

6 *Id*.

7 *See* Modification of Request for Extension of Time of Atlantic Coast Pipeline, LLC, et al., FERC Docket No. CP15-554, Document Accession #: 20200710-5088 (July 10, 2020).

8 *See* Notice of Intent, FERC Docket No. CP15-554, Document Accession #: 20210504-3044 (May 4, 2021).

treating the wind down as almost a new project, requiring a new environmental review and environmental impact statement. Thus, even cancelling the pipeline and abandoning the project entirely will involve significant costs to Atlantic in restoration and remediation of disturbed property.

[4] — Colonial Pipeline Ransomware Attack.

Cyber attacks have become a prevalent, persistent threat to all facets of life, including the successful operation of business technology. Attacks upon critical infrastructure, including pipelines, have become increasingly, and alarmingly, common.

Colonial Pipeline operates one of the largest pipeline systems for refined oil products in the United States.[9] Much of the East Coast of the United States depends on this pipeline for fuel products, including jet fuel, gasoline, diesel, and heating oil.[10] On May 6, 2021, a group known as DarkSide launched a ransomware attack and breached and overtook control of Colonial Pipeline's systems.[11] A ransomware attack is a form of malware designed to encrypt files on a device, rendering the files and the systems that rely on them unusable.[12] The attacker often demands a ransom in order to decrypt those files.[13] The attack disrupted critical fuel supply to the East Coast, causing shortages at gasoline filling stations, and a jet fuel shortage at major airports.[14] Shortly after the hack, Colonial Pipeline conceded to the ransom demanded by

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9 *Colonial Pipeline*, McKinsey Energy Insights https://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/colonial-pipeline/.

10 David E. Sanger, Clifford Krauss, and Nicole Perlroth, *Cyberattack Forces a Shutdown of a Top U.S. Pipeline,* N.Y. Times (May 8, 2021), https://www.nytimes.com/2021/05/08/us/politics/cyberattack-colonial-pipeline.html.

11 *Id*.

12 Stop Ransomware, https://www.cisa.gov/stopransomware (last visited November 1, 2021).

13 *Id*.

14 Tracy Rucinski, *American Airlines adds stops to two flights after pipeline outage,* Reuters (May 10, 2021), https://www.reuters.com/business/energy/american-airlines-adds-fuel-stops-two-flights-after-pipeline-outage-2021-05-11/.

DarkSide, paying roughly 75 Bitcoin, or about $5 million to re-gain control of its systems.[15]

The federal government issued a variety of responses to the ransomware attack. On May 12, 2021, President Biden signed an executive order that: (1) removes barriers to threat information sharing between government agencies and the private sector; (2) implements stronger cybersecurity standards in the federal government; (3) establishes baseline security standards for developments of software sold to the government; (4) implements a pilot program to create an "energy star" type label so the public can determine whether a software was developed securely; (5) creates a standard playbook for responding to cyber incidents for federal agencies; and (6) improves investigative and remediation capabilities.[16] Further, FERC issued a statement calling for an examination of mandatory pipeline cyber standards.[17] This federal review could have significant impacts industry wide as the federal government looks to harden cyber systems against attack.

The Pipeline Security Act[18] ("PSA") was also reintroduced in Congress following the attack. The proposed legislation is the first of multiple legislative responses to the Colonial Pipeline ransomware attack. The legislation seeks to codify the roles of the Transportation Security Administration ("TSA") and the Cybersecurity and Infrastructure Security Agency in securing critical infrastructure pipelines against cybersecurity threats, acts of terrorism, and other threats to physical and cybersecurity of the pipelines or related facilities. Critical infrastructure pipelines are so vital to the United States that their incapacity or destruction would have a debilitating impact on physical or

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15 Nicole Perlroth, *Colonial Pipeline paid 75 Bitcoin, or roughly $5 million, to hackers*, N.Y. Times (May 13, 2021), https://www.nytimes.com/2021/05/13/technology/colonial-pipeline-ransom.html.

16 Exec. Order No. 14028, 86 Fed. Reg. 26633 (May 12, 2021).

17 Press Release, Federal Energy Regulatory Commission, Statement from FERC Chairman Richard Glick: Chairman Glick and Commissioner Clements Call for Examination of Mandatory Pipeline Cyber Standards in Wake of Colonial Pipeline Ransomware Incident (May 10, 2021) (available at https://www.ferc.gov/news-events/news/statement-ferc-chairman-richard-glick-chairman-glick-and-commissioner-clements).

18 Pipeline Security Act, H.R.3243, 117th Cong. (2021).

economic security, public health, or safety within the United States.[19] The PSA would establish a pipeline security section within the TSA, require TSA to implement a strategy to complete hiring and filling of its security staff, and require TSA to convene at least two industry engagement days to work with pipeline facilities and transportation stakeholders on pipeline security. This bill is currently pending in Congress, sponsored by Rep. Cleaver (D-MO-5). It has bipartisan co-sponsors and was placed on the union calendar on July 13, 2021. It is still pending in the House.

The Colonial Pipeline ransomware attack introduces a host of questions that may not have been previously considered by infrastructure and energy companies. Should a ransom be paid in the event of a cyber attack that disrupts energy supply? What are the implications of paying or not paying a ransom? If a ransom is not paid, how will that decision impact current and future operations? If the ransom is paid, is there any assurance the bad actor will release (or has the capability to release) the encrypted data? There are no guarantees. What are the legal ramifications of paying a ransom? Companies should consider sanctions lists maintained by the Office of Foreign Assets Control ("OFAC") and determine what other laws may apply depending on the jurisdiction. Violations of OFAC sanctions can lead to civil and criminal penalties. Under its cyber-related sanctions program, OFAC has identified numerous bad actors, who "fund activities adverse to the national security and foreign policy objectives of the United States."[20] Payment of ransom to these bad actors may violate OFAC regulations promulgated under authority granted by the International Emergency Economic Powers Act[21] or the Trading with the Enemy Act.[22] Per OFAC, victims of ransomware should

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19 Infrastructure Security, https://www.cisa.gov/infrastructure-security (last visited November 1, 2021).

20 OFAC Advisory on Potential Sanctions Risk for Facilitating Ransomware Payments, October 1, 2020, (available at https://home.treasury.gov/system/files/126/ofac_ransomware_advisory_10012020_1.pdf).

21 50 U.S.C. §§ 1701–06.

22 50 U.S.C. §§ 4301–41.

contact OFAC, the Department of Treasury, Financial Crimes Enforcement Network, and/or the Federal Bureau of Investigation.[23]

[5] — The CLEAN Future Act.

On March 2, 2021, Rep. Frank Pallone, Jr. (D-NJ) introduced a bill in Congress titled the CLEAN Future Act.[24] The purpose of the bill is "to build a clean and prosperous future by addressing the climate crisis, protecting the heath and welfare of all Americans, and putting the Nation on a path to a net-zero greenhouse gas economy by 2015, and for other purposes."[25] It includes setting a nationwide Clean Electricity Standard that requires all retail electricity suppliers to obtain 100% renewable electricity by 2035. This standard would mandate retail suppliers to provide an increasing supply of renewable electricity to consumers starting in 2023. It would also authorize $100 billion in funding for a new "Clean Energy and Sustainability Accelerator" to mobilize public and private investments for financing low and zero emissions technology.[26] The bill directs the Environmental Protection Agency to enact standards for all natural gas pipelines, all new and existing sources with equipment that handle liquefied natural gas, and offshore petroleum and natural gas production facilities.[27] It further amends the Natural Gas Act to prevent pipeline companies from using eminent domain until they have obtained all the necessary federal and state permits. This could create a practical problem which could, in certain circumstances, leave pipeline companies in a situation where it is unable to obtain the requisite government permits because it cannot access the properties in question to do the studies needed to complete the permitting process. Further, the bill

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23 OFAC Advisory on Potential Sanctions Risk for Facilitating Ransomware Payments, October 1, 2020, (available at https://home.treasury.gov/system/files/126/ofac_ransomware_advisory_10012020_1.pdf).

24 CLEAN Future Act, H.R.1512, 117th Cong. (2021).

25 *Id*.

26 *Id*.

27 *Id*.

prohibits use of eminent domain for pipelines attached to liquefied natural gas facilities.[28]

§ 2.03. Pipeline Litigation.

[1] — *Mt. Valley Pipeline, LLC v. 6.56 Acres.*[29]

Mountain Valley, at its heart, is a re-affirmation of the right of a condemnor to obtain pre-judgment access to a condemned property prior to a final order of condemnation through a preliminary injunction initially established in *East Tennessee Natural Gas Company v. Sage,* 361 F.3d 808 (4th Cir. 2004). With approval from FERC, Mountain Valley Pipeline, LLC is constructing an interstate natural gas pipeline through West Virginia and Virginia. To acquire land necessary for the project that could not be obtained through negotiations, Mountain Valley commenced eminent domain proceedings under the Natural Gas Act in the Western District of Virginia and the Northern District of West Virginia. The district courts granted Mountain Valley's motions for preliminary injunction and partial summary judgment, which allowed Mountain Valley immediate access to the condemned properties before the determination of just compensation. The landowners appealed to the Fourth Circuit, challenging the district courts' power to grant immediate access. The Fourth Circuit denied the appeal, stating "*Sage* squarely forecloses the Landowners' argument that the district courts lacked the authority to grant immediate possession in a Natural Gas Act condemnation."[30] The Supreme Court declined to hear the case.[31] As a result, *Sage* remains the established law in the Fourth Circuit and other jurisdictions.[32]

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28 *Id*.

29 Mountain Valley Pipeline, LLC v. 6.56 Acres, 915 F.3d 197 (4th Cir. 2019).

30 *Id*.

31 Givens v. Mountain Valley Pipeline, LLC, 140 S. Ct. 300 (2019).

32 *See*, e.g., Transcon. Gas Pipe Line Co., LLC v. Permanent Easements for 2.14 Acres, 907 F.3d 725 (3d Cir. 2018); Fla. Southeast Connection v. 0.821 Acres, 223 F. Supp. 3d 1227 (M.D. Fla. 2016).

[2] — *PennEast Pipeline Co. v. New Jersey.*[33]

PennEast Pipeline Company, LLC is constructing a FERC-approved interstate natural gas pipeline from Pennsylvania to New Jersey.[34] PennEast filed suit in the US District Court for the District of New Jersey under the Natural Gas Act to condemn easement rights from the State of New Jersey. New Jersey moved to dismiss the action based on sovereign immunity. The district court denied the motion to dismiss and allowed PennEast immediate access to the properties in question. New Jersey appealed, and the Third Circuit reversed, holding that Natural Gas Act did not delegate to private companies the federal government's ability to sue nonconsenting states in federal court.[35] The Eleventh Amendment to the Constitution prevents federal courts from exercising jurisdiction over state defendants unless the state consents to jurisdiction.[36]

The Supreme Court granted certiorari and heard arguments on April 28, 2021 to decide whether a private company with the federal right of eminent domain under the Natural Gas Act could condemn state-owned land in federal court. In a 5-4 opinion, the Court held:

> [T]he Federal Government can constitutionally confer on pipeline companies the authority to condemn necessary rights-of-way in which a State has an interest. … Although nonconsenting States are generally immune from suit, they surrendered their immunity from the exercise of the federal eminent domain power when they ratified the Constitution. That power carries with it the ability to condemn property in court. Because the Natural Gas Act delegates the federal eminent domain power to private parties, those parties can initiate condemnation proceedings, including against state-owned property.[37]

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33 PennEast Pipeline Co., LLC v. New Jersey, 141 S. Ct. 2244 (2021).

34 *Id*. at 2247.

35 In re PennEast Pipeline Co., LLC, 938 F.3d 96, 104 (3d Cir. 2019).

36 *See* Hans v. Louisiana, 134 U.S. 1 (1890); Gunter v. Atl. Coast Line R. Co., 200 U.S. 273 (1906).

37 PennEast Pipeline Co., 141 S. Ct. at 2251–52.

This decision confirms the right of pipeline companies to condemn property owned by state or local governments in federal court. This critical right for interstate pipeline companies allows projects regulated by the FERC and federal government to proceed unimpeded by the states through which a given project crosses. The Third Circuit opinion, along with a few other district court cases,[38] created a period of uncertainty over a pipeline company's eminent domain rights with respect to localities. *PennEast* resolved that uncertainty in favor of pipeline companies.

[3] — *City of Oberlin v. FERC*.

This case decided whether a pipeline that will use a portion of its capacity to supply energy to Canada serves the public good of the United States and whether FERC erred in taking the capacity to be consumed by Canada into account in determining the need for the pipeline. The City of Oberlin, Ohio and a coalition of landowners (collectively, "Oberlin") asked the Circuit Court of Appeals for the District of Columbia, on a direct appeal from the FERC decision, to vacate FERC's order authorizing Nexus Gas Transmission, LLC to construct and operate an interstate natural gas pipeline.[39] The pipeline was approved with eight precedent agreements, accounting for 59% of the pipeline's total proposed capacity — two of which were with Canadian companies serving customers in Canada. Oberlin argued that Nexus and FERC could not establish a public interest and need based partly on the exportation of natural gas outside the United States. The DC Circuit agreed in part with Oberlin and directed FERC to explain why the agency considered the export precedent agreements with foreign shippers when analyzing market need for a domestic pipeline.

In September of 2020, FERC affirmed the prior approval of the Nexus pipeline with a 2-1 vote.[40] FERC noted that exports to free trade partners, like Canada, are a public interest. FERC also explained that the pipeline

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38 *See e.g*. Sabine Pipe Line, LLC v. A Permanent Easement, 327 F.R.D. 131 (E.D. Tex. 2017).

39 City of Oberlin v. FERC, 937 F.3d 599, 601 (D.C. Cir. 2019).

40 Nexus Gas Transmission, LLC, 172 FERC ¶ 61,199 (2020).

maintained a domestic component, which would have independently warranted approval, without the Canadian precedent agreements.[41] FERC went on to note a multitude of other reasons to affirm its prior order, noting that the pipeline contributes to the overall development of the gas market and enhances the pipeline grid, provides gas transport to new markets in northern Illinois and other midwestern markets, strengthens domestic economy and international trade balance, and creates jobs.[42] The FERC's subsequent order is again on appeal with the DC Circuit.[43]

§ 2.04. Federal Energy Regulatory Commission.

[1] — FERC Order No. 871.

On May 4, 2021, FERC issued Order No. 871, which precludes construction of any kind while FERC is considering requests for rehearing. This order is a departure from the previous practice of allowing construction to proceed while a rehearing request was pending. The order further clarified that the bar to construction lasts until the earlier of: (1) when a rehearing request is no longer pending, or (2) 90 days after request for rehearing may be denied by operation of law. In conjunction with this order, FERC announced a general policy of staying certificate orders for natural gas pipelines during the rehearing period.

[2] — Considering Impact to Climate.

FERC Chairman Richard Glick has established that a pipeline's impact on the climate is a priority consideration in the approval process of new pipeline projects. Chairman Glick stated:

> "[g]oing forward, we are committed to treating greenhouse gas emissions and their contribution to climate change the same as all other environmental impacts we consider. […] A proposed pipeline's

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41 "Finally, in the alternative, we find that even if the NEXUS project had been presented without the two Canadian companies' precedent agreements, the project would still have had precedent agreements adequate to demonstrate need in support of a public convenience and necessity finding." *Id*. at 62301.

42 *Id*.

43 *See* City of Oberlin v. FERC, No. 20-1492, (D.C. Cir.) (filed Dec. 7, 2020).

> contribution to climate change is one of its most consequential environmental impacts and we must consider all evidence in the record […].[44]

In March of 2021, for the first time, FERC assessed the significance of a proposed natural gas pipeline's greenhouse gas emissions and their contribution to climate change. "In future proceedings, we will continue to consider all appropriate evidence regarding the significance of a project's reasonably foreseeable GHG emissions and those emissions' contribution to climate change."[45] FERC's subsequent orders are reflective of this newly stated policy.[46]

§ 2.05. Conclusion.

Despite the push for renewable and electric energy, pipelines and the resources they deliver remain critical to this country's infrastructure. The COVID-19 pandemic upended energy markets on many levels. Cyber attacks present a new threat to the stability of energy production and delivery. Environmental regulations and activism present challenges to the development of new pipeline infrastructure and to the maintenance and upkeep of existing infrastructure. The response to these critical issues will help shape the energy future of the United States.

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44 Press Release, Federal Energy Regulatory Commission, FERC Reaches Compromise on Greenhouse Gas Significance (March 18, 2021) (available at https://www.ferc.gov/news-events/news/ferc-reaches-compromise-greenhouse-gas-significance).

45 Northern Natural Gas I, FERC Docket No. CP20-487-000 (March 22, 2021).

46 *See e.g.*, Northern Natural Gas II, FERC Docket No. CP20-503-000 (May 20, 2021) ("*[o]ur approval of this proposal would not constitute a major federal action significantly affecting the quality of the human environment*."); Tuscarora Gas Transmission Company, FERC Docket No. CP20-486-000 (May 20, 2021) (""*The forgoing analysis of greenhouse gas emissions is offered for information purposes only, does not inform any part of this order's holding, and shall not serve as precedent for any future order.").*

Chapter 3

Current Energy Markets and Financing Trends

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§ 3.01. Introduction.

The last 18 months have been very up and down in the commodity markets. Current oil futures contracts imply that oil prices will remain in the 60 to 70 dollar range through the end of 2021. Drilling rig counts are slowly increasing off COVID lows of last year. Exploration and production (E&P) companies will need to continue to operate within cash flow generated due to lack of debt and equity growth financing availability. A new problem is developing — energy service businesses are unable to find workers willing to come back to the sector. The lack of service company crews could hold back United States shale's ability to flood the market with new supply in the short term. Currently, the crude market is experiencing price volatility driven from two different affronts: (i) demand destruction due to COVID-19 and its universal impact on the global economy and (ii) oversupply of hydrocarbons because of late production cuts from international and domestic energy producers. Cash flow and demand constraints on domestic E&P companies should hold rig counts close to current levels. At the end of 2020, E&P

companies cut domestic spending capital expenditure budgets by about 32 billion dollars. Until the world economy and oil markets start to grow again oil demand is likely to stay stuck close to current levels.

The equity capital markets have not seen very much in the way of traditional energy new issuances in 2021. To date the only initial public offering (IPO) for an E&P company was Vine Energy's offering in February. Some of the larger publicly listed E&P companies have had success with follow on offerings but in general the window is shut today for new E&P equity offerings. The debt markets have experienced more activity than equity markets but successful offerings tend to be concentrated in larger credit worthy upstream companies. In 2021, the borrowing costs are higher but for the right issuer deals can close. Smaller operators are having less success in the debt markets with several "market testing" processes never closing in the high yield market. Environment Social and Governance (ESG) concerns and portfolio performance hits taken over the last 24 months have significantly limited the appetite of commercial lenders for anything in traditional energy.[1]

All Transactions Announced Date	Target/Issuer	Transaction Types	Transaction Status	Total Transaction Value ($USDmm)	Transaction Primary Features
May 20, 2021	Diversified Energy Company PLC (LSE:DEC)	Public Offering	Closed	225	Follow-on Equity Offering
May 10, 2021	Pioneer Natural Resources Company (NYSE:PXD)	Public Offering	Closed	959	Follow-on Equity Offering
March 2, 2021	Magnolia Oil & Gas Corporation (NYSE:MGY)	Public Offering	Closed	179	Follow-on Equity Offering
February 22, 2021	Vine Energy Inc. (NYSE:VEI)	Public Offering	Closed	301	IPO

1 *Public company profiles*, S&P Capital IQ (database), September 2021.

All Transactions Announced Date	Target/Issuer	Transaction Types	Transaction Status	Total Transaction Value ($USDmm)	Transaction Primary Features
February 3, 2021	Northern Oil and Gas, Inc. (NYSEAM: NOG)	Public Offering	Closed	122	Follow-on Equity Offering
January 7, 2021	Antero Resources Corporation (NYSE:AR)	Public Offering	Closed	199	Follow-on Equity Offering
December 8, 2020	Talos Energy Inc. (NYSE:TALO)	Public Offering	Closed	71	Follow-on Equity Offering
October 27, 2020	EQT Corporation (NYSE:EQT)	Public Offering	Closed	310	Follow-on Equity Offering
September 10, 2020	Brigham Minerals, Inc. (NYSE:MNRL)	Public Offering	Closed	36	Follow-on Equity Offering
August 12, 2020	Southwestern Energy Company (NYSE:SWN)	Public Offering	Closed	138	Follow-on Equity Offering
June 9, 2020	Brigham Minerals, Inc. (NYSE:MNRL)	Public Offering	Closed	91	Follow-on Equity Offering

§ 3.02. Financing Trend #1 in 2021: Special Purpose Acquisition Companies.

A special purpose acquisition company, or SPAC, is a blank check company formed for the purpose of effecting a merger, share exchange, asset acquisition, share purchase or similar business combination with one or more businesses. A SPAC provides an alternative to either traditional IPOs for private companies or a merger or acquisition (M&A) exit. SPAC sponsors have industry expertise and/or strong deal making reputations which would facilitate completing a deal with a public company. The SPAC lists on NASDAQ or the New York Stock Exchange (NYSE) and has a limited time to complete a business combination (typically 18-24 months).

SPAC IPO proceeds are held in escrow solely to be used in completing a business combination. When a merger is completed, it is called a "De-SPAC" transaction. If a SPAC fails to complete a De-SPAC transaction within 18-24 months, the SPAC is forced to liquidate and funds in trust returned to investors. A SPAC is required to target a transaction value where the target company must be at least 80 percent of trust assets.

[1] — Structure.

The capital structure of a SPAC has some key differences to an IPO. A SPAC sponsor receives a "promote" — typically 20 percent of SPAC's common stock for nominal consideration. Sponsors also purchase Warrants in a concurrent private placement. Typically, a SPAC offers Units in the IPO where each Unit comprises one share of common stock and one (or one half or one third) warrant to purchase common stock. Units are typically priced at ten dollars and warrants are typically priced at 11 dollars and 50 cents per share, or "out of the money." Warrants are redeemable by the SPAC after the business combination for one cent per warrant only if the trading price reaches a specific price. Warrants usually are exercisable on later of (i) 30 days after completion of business combination or (ii) 12 months post-IPO. In general SPAC offering size is less than 500 million dollars with most falling in the 100 to 300 million dollar range. SPAC underwriter spreads are generally five and one half percent with three and one half percent deferred until "De-SPAC" transaction occurs.

[2] — Benefits and Challenges.

A SPAC structure offers many benefits to the issuer and target "Merger Company." A SPAC is an alternative method to access public markets with many of the same benefits as an IPO but with less time required. Generally, in a De-SPAC merger active stockholders can retain majority of shares post-merger while publicly traded shares provide path to liquidity for family members or shareholders not active in business. A SPAC also allows the merged companies a larger platform to raise debt at the time of the combination. SPACs have proliferated in last 24 months to the point that there is high risk of not enough quality targets for all SPACs to transact. This

dynamic should which lead to a higher likelihood of completed transaction in near term as compared to a traditional IPO or a SPAC transaction in 2019 or before.

The SPAC structure also has an increasing amount of hurdles headed its way which include increased government and regulatory scrutiny, strict adherence to global and national accounting standards and the overall increased costs associated with registering as and being a public company. From a structural perspective, some SPAC hurdles include the requirement of the approval of a majority (or super-majority) of its shareholders at a special shareholders meeting. Typically, SPAC's sponsors own about 20 percent of outstanding common stock post-IPO. The SPAC IPO raise is typically about one quarter to one third of expected enterprise value of target to minimize effect of dilution resulting from founder shares and warrants. Some SPAC dilution can be mitigated with a private investment in public equity (PIPE) transaction at the De-SPAC close. Finally, SPACs typically have 24 months to "De-SPAC" in a transaction or they must liquidate and return the funds from escrow.

SPACs have also encountered new legal scrutiny around several target areas. The biggest new area of legal focus is around the treatment of warrants as equity versus liabilities in financial disclosures. The warrant disclosure change required the updating of financials for many older SPACs and will likely continue to be a hot point with investors and regulators.

[3] — Market Activity.

The traditional energy market participated in the early days of SPAC activity (2016 to 2018) with several successful transactions and a couple unsuccessful transactions. The SPAC energy market activity recently has focused more around CleanTech, EV Markets, and Renewables. Large PE backed shale companies are hoping sustained cash flows will bring traditional energy companies back into focus for SPACs looking for sizeable De-SPAC transactions.

Examples of Traditional Energy SPACs

SPAC	IPO Date	Size ($MM)	Status
SIlver Run Acq	2/26/2016	$500	Formed Centennial [2]
Matlin & Partners Acq	3/18/2017	$325	US Well Service [3]
Silver Run Acq 2	3/24/2017	$1,035	AltaMesa (BK) [4]
Kayne Anderson Acq	3/30/2017	$377	Atlas Midstream [5]
Vantage Energy Acq	4/10/2017	$552	Dissolved — failed merger [6]
TPG Pace Energy	5/5/2017	$650	Magnolia O&G [7]

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2 Press Release, Centennial Resource Development, Inc., Silver Run Acquisition Corporation Completes its Acquisition of an 89% Controlling Interest in Centennial Resource Production, LLC (October 11, 2016) (available at http://ir.cdevinc.com/news-releases/news-release-details/silver-run-acquisition-corporation-completes-its-acquisition-89).

3 Press Release, Matlin & Partners Acquisition Corporation and US Well Services, LLC, Matlin & Partners Acquisition Corporation and U.S. Well Services, LLC Complete Business Combination (November 9, 2018) (available at https://www.prnewswire.com/news-releases/matlin--partners-acquisition-corporation-and-us-well-services-llc-complete-business-combination-300747703.html).

4 Press Release, Alta Mesa Holdings, LP, Silver Run Acquisition Corporation II Completes its Business Combination with Alta Mesa Holdings, LP and Kingfisher Midstream, LLC and Becomes Alta Mesa Resources, Inc. (February 9, 2018) (available at https://www.globenewswire.com/news-release/2018/02/09/1338643/0/en/Silver-Run-Acquisition-Corporation-II-Completes-its-Business-Combination-with-Alta-Mesa-Holdings-LP-and-Kingfisher-Midstream-LLC-and-Becomes-Alta-Mesa-Resources-Inc.html).

5 Press Release, Altus Midstream, Apache and Kayne Anderson Acquisition Corporation Announce Closing of Transaction to Create Altus Midstream Company, a Pure-Play, Permian Basin Midstream C-Corp (November 12, 2018) (available at https://www.globenewswire.com/news-release/2018/11/12/1649633/0/en/Apache-and-Kayne-Anderson-Acquisition-Corporation-Announce-Closing-of-Transaction-to-Create-Altus-Midstream-Company-a-Pure-Play-Permian-Basin-Midstream-C-Corp.html).

6 Press Release, Vantage Energy, Vantage Energy Acquisition Corp. Announces Redemption of Public Shares and Subsequent Dissolution (March 29, 2019) (available at https://www.globenewswire.com/news-release/2019/03/29/1790147/0/en/Vantage-Energy-Acquisition-Corp-Announces-Redemption-of-Public-Shares-and-Subsequent-Dissolution.html).

7 Press Release, Magnolia Oil & Gas Corporation and TPG Pace Energy, TPG Pace Energy Holdings Corp. Announces Closing of Business Combination with EnerVest's South Texas Division, Combined Company to be Named Magnolia Oil & Gas Corporation (July 31, 2018) (available at https://www.businesswire.com /news/home/20180731005839/en/TPG-Pace-Energy-Holdings-Corp.-Announces-Closing-of-Business-Combination-with-EnerVest%E2%80%99s-South-Texas-Division-Combined-Company-to-be-Named-Magnolia-Oil-Gas-Corporation).

SPAC	IPO Date	Size ($MM)	Status
National Energy Services	5/11/2017	$210	Gulf Energy [8]
Sentinel Energy Services	11/3/2017	$345	Dissolved — failed merger [9]
Pure Acq	4/13/2018	$102	High-Peak Energy [10]
Trident Acq	5/29/2018	$201	Lottery.com (changed focus) [11]
HL Acq	6/27/2018	$55	Fusion Fuel Green [12]
Osprey Energy Acq	8/23/2018	$275	Falcon Minerals/Blackstone[13]
Switchback Energy Acq	7/26/2020	$314	Entered EV market [14]

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8 Press Release, National Energy Services Reunited Corp., National Energy Services Reunited Corp. Announces the Completion of Its Business Combination with Gulf Energy SAOC and National Petroleum Services (June 7, 2018) (available at https://www.globenewswire.com /en/news-release/2018/06/07/1518651/0/en/National-Energy-Services-Reunited-Corp-Announces-the-Completion-of-Its-Business-Combination-With-Gulf-Energy-SAOC-and-National-Petroleum-Services.html).

9 Press Release, Sentinel Energy Sources, Inc., Sentinel Energy Services Inc. Announces Cancelation of Stockholder Meeting and Redemption of Public Shares (November 6, 2019) (available at https://www.globenewswire.com/news-release/2019/11/06/1942202/0/en/Sentinel-Energy-Services-Inc-Announces-Cancelation-of-Stockholder-Meeting-and-Redemption-of-Public-Shares.html).

10 Press Release, Pure Acquisition Corp., Pure Acquisition Corp. Closes Business Combination for Company to be Named HighPeak Energy, Inc. (August 24, 2020) (available at https://www.globenewswire.com/news-release/2020/08/24/2082407/0/en/Pure-Acquisition-Corp-Closes-Business-Combination-for-Company-to-be-Named-HighPeak-Energy-Inc.html).

11 Press Release, Lottery.com, Lottery.com and Trident Acquisitions Corp. Announce Closing of Business Combination (October 29, 2021) (available athttps://www.globenewswire.com/news-release/ 2021/10/29/2323936/0/en/Lottery-com-and-Trident-Acquisitions-Corp-Announce-Closing-of-Business-Combination.html).

12 Press Release, HL Acquisitions Corp, HL Acquisitions Corp. and Fusion Fuel Green PLC Announce Closing of Business Combination; Fusion Fuel to Trade on Nasdaq Global Market Under the Ticker "HTOO" Beginning on December 10 (December 10, 2020) (available at https://www.globenewswire.com/news-release/2020/12/10/2143314/0/en/HL-Acquisitions-Corp-and-Fusion-Fuel-Green-PLC-Announce-Closing-of-Business-Combination-Fusion-Fuel-to-Trade-on-Nasdaq-Global-Market-Under-the-Ticker-HTOO-Beginning-on-December-10.html).

13 Press Release, Blackstone, Osprey Energy Acquisition Corp. and Blackstone's Royal Resources Announce Combination to Form Falcon Minerals Corporation, a Publicly Traded Oil-Weighted Minerals Company (June 4, 2018) (available athttps://www.businesswire.com/news/home/ 20180604005654/en/Osprey-Energy-Acquisition-Corp.-and-Blackstone%E2%80%99s-Royal-Resources-Announce-Combination-to-Form-Falcon-Minerals-Corporation-a-Publicly-Traded-Oil-Weighted-Minerals-Company).

14 SWITCHBACK, https://switchback-energy.com (last visited September 2, 2021).

§ 3.03. Financing Trend #2 in 2021: Private Equity.

[1] — Value Creation.

Private equity is an asset class which invests in equity securities of operating companies that are not public traded. Private equity funds face high return expectations by their investors which only few in the industry can meet. Private equity funds have four ways to create value for their investors:

- First, private equity funds usually challenge the way the businesses are run and improve operations of these businesses. Although some of very best private equity firms have developed effective re-engineering capabilities to add value to their investments and generate superior returns, this is not the main driver of value creation
- Second, business financing can be improved since many private equity firms have better access to credit markets. Some of them can use the tax shield on the acquisition debt to create value
- Third, incentives that motivate managers to "behave like owners" are at the heart of private equity value proposition. Having the right people in place is critical to success. Private equity investors retain senior managers capable of driving value growth and replace those not up to the task. Incentives between investors and management are fully aligned
- Last but not least, effective contractual structuring of the investment is also a source of value creation in private equity

[2] — Advantages and Challenges.

Private equity backed transactions have specific advantages. Of all the alternative investment classes, private equity can usually provide the largest amounts of money with the deals measured in hundreds of millions or even billions of dollars. These large amounts of funding lead to more opportunities as transaction size is not a major consideration when analyzing a potential investment. Generally, private equity firms are very hands on investors who post close will help re-evaluate every aspect of the business to see how its value may be maximized. Sellers to private equity groups find that the inclusion of experienced professionals intimately involved in a business can also result in major improvements, especially when the General Partner (the

private equity fund), the Limited Partners (the private equity fund's investors), and the firm's managers interests are aligned thanks to incentives.

Private equity backed transactions also come with a series of hurdles which sellers/partners should be aware of as they enter into a transaction. With private equity, a seller generally received more proceeds in their sale transaction, but usually private equity are control investors. As private equity firms often demand a majority stake it often results in the seller left with little or nothing of its ownership going forward. It is a big trade off and often business owners will balk at giving up control when they consider alternatives. Private equity firms' definition of value is very specific and mostly focused on the financial value of the business on a particular date three to five years after the initial investment, when the firm sells its stake and books a profit. Business owners often have a much broader definition of value, with a longer-term outlook and more concern for things like relationships with employees and customers, and reputation, which can lead to clashes post close. The private equity industry is comprised of institutional investors such as pension funds, and large private equity firms funded by accredited investors and rarely can retail investors participate. The private equity institutional investors typically hold their private equity investments for over ten years. The long hold period and high illiquidity lead to higher expected returns.

[3] — Legal Issues.

The legal hot topics for private equity backed transactions tend to be less stringent given the long period of existence of these types of transactions. A key area of legal focus is around the due diligence process prior to closing a transaction and the risks that rapidly change in the world. An example is private equity due diligence for target oil service companies now needs to focus on operational, supply chain and data privacy matters while upstream portfolio companies diligence focus can be on engineering, geology and asset valuations. Representation and warranty insurance has helped reduce some of the diligence risk for buyers but all parties need to be aware of the ever changing world risk demands. Finally, limited partners and investors have increased their demand for ESG reporting across the board which plays into upfront and ongoing diligence efforts.

§ 3.04. Spotlight on Environmental, Social, and Governance Factors in Energy Finance.

Energy companies have the largest exposure to the Environmental ("E") component of general ESG goals. Unless a company solely generates energy via wind and solar, its operations most likely will have a negative drag on environment. Investment dollars historically focused on traditional oil and gas markets are now flowing into projects and companies with robust and materially relevant ESG practices. Money center banks are declining to renew credit facilities based on internal ESG goals and pressure from institutional investors/activist groups. The new institutional investor focus has led energy specific private equity funds to aggressively search for opportunities with positive ESG considerations. ESG reporting is no longer just a public or big company issue. Company practices around ESG communications, reporting, and data analytics will have to evolve and mature rapidly to keep up with investor demands. Larger customers and investors will continue to push their ESG requirements down on suppliers/service providers. The recent changes in both federal and state government leadership has accelerated the ESG movement and may include new influence over emissions, public lands, procurement, foreign relations, trade, and agency appointments. For most energy service businesses, innovation/technology will be the most-critical lever to achieve material improvements in ESG performance.

Climate change regulation is likely to receive greater attention in 2021/2022 globally, as economies seek to drive investment capital from "brown" to carbon-neutral projects and activities. The election of President Biden resulted in a drive for tighter environmental regulation and standards in the United States. China formulated an action plan in 2021 aimed at ensuring the CO2 emissions peak before 2030. Germany held general elections in September of 2021 and carbon emissions were prominently discussed. In 2020, the EU published its emission reduction target for 2030 to at least 55 percent. Renewable growth will accelerate in 2021 as the new administration starts to execute on a platform that includes rejoining the Paris Climate Accord, investing two trillion dollars in clean energy, and fully decarbonizing the power sector by 2035 in order to achieve a larger goal of net-zero carbon emissions by 2050. United States Energy Information Administration forecasts electricity generation from renewable energy sources to rise from

20 percent in 2020 to 21 percent in 2021 and to 23 percent in 2022. The nuclear share of United States generation would decline from 21 percent in 2020 to 20 percent in 2021 and to 19 percent in 2022. Solar and wind will account for 70 percent of the nearly 40GW of new large-scale United States electricity generating capacity that developers plan to bring into commercial operation in 2021.

Risks to the energy sector driven by ESG include but are not limited to a steady decline in demand for product as global markets move to more environmentally friendly energy sources, financing and credit availability, long-term environmental legal exposure to service businesses, lawsuits from outside groups targeting customers in effort to change corporate behavior, and additional risk from industry's slow adoption of Social and Governance aspects of ESG.

Chapter 4

Cross-Unit Wells[1]

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1 The authors wish to thank Baylee Abbott, West Virginia University College of Law class of 2022, for her invaluable assistance in researching and preparing this chapter.

2 At the time of presentation and preparation of the chapter. As of the time of publication, Mr. Tarantelli now works for Honeywell in Charlotte, North Carolina.

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§ 4.01. Introduction.

This chapter focuses on the legal frameworks for drilling unconventional horizontal oil and gas wells across existing voluntary or statutory unit boundaries. Since the widespread drilling of unconventional horizontal wells began in the mid-2000's, technological innovations have increased the length of horizontal wellbores dramatically, from hundreds of feet to tens of thousands of feet. Longer laterals are economically more efficient and have less surface impact than shorter laterals. However, this technological progress creates problems for oil and gas operators who wish to use these new longer, more efficient lateral wellbores on existing units that do not contain sufficient acreage to permit the new longer wells. The primary methods used by oil and gas operators to permit longer laterals on existing units are: 1) amending units to permit longer laterals; 2) obtaining production sharing agreements from all lessors in a unit; 3) overlapping new units with existing units; and 4) drilling allocation wells across existing units. First, we examine these methods and the respective advantages and disadvantages of each approach. Second, we examine and compare the legal frameworks for cross-unit wells in Pennsylvania, Texas and Oklahoma in detail and offer a brief review of other jurisdictions that have permitted cross-unit wells by statute or regulation.

§ 4.02. Developments in Drilling Technology.

For most of the history of oil and gas development, "conventional" vertical wells have predominated in producing oil and gas from subsurface sand formations. Although deviated wells have a long history in oil and gas operations, lateral wellbores did not become widespread until the boom of "unconventional" oil and gas wells combining lateral wellbores with hydraulic fracturing (the pumping of a mixture of water and proppants at high pressure into a wellbore to increase the permeability of the rock). These methods permitted the production of oil and gas from tight shale formations, such as

the Marcellus formation and Utica formation in Appalachia, that were not commercially viable for oil and gas operations using traditional methods.[3]

Lateral wellbores have greatly increased in length over the past 15 years. Drilling laterals out tens of thousands of feet dramatically reduces the number of wells needed to develop an unconventional oil and gas formation. This in turn significantly reduces the cost of development for oil and gas operators.[4] Additionally, longer wellbores mean fewer wellpads and less surface disturbance, helping to conserve natural resources.

The economic and environmental advantages make longer laterals an essential technological innovation for oil and gas producers. However, these wells create challenges for operators who wish to drill longer laterals on units that were not created in anticipation of well laterals that can extend tens of thousands of feet. The new laterals are often simply too long to fit inside the boundaries of existing units. Voluntary and regulatory oil and gas units are premised on the assumption that all of a well will be located within the unit. This assumption supports the acreage-based division of royalties among tracts in a unit typically found in lease pooling clauses and in regulatory division orders. Additionally, jurisdictions with mandatory spacing rules require that wells be set back from unit boundaries. Wells that cross units violate boundary setback rules and questions arise about the proper allocation of royalties when a well is located in multiple units.

Some jurisdictions have responded to the challenge of longer laterals by expressly permitting operators to drill cross-unit wells. As described in greater detail below, Pennsylvania has recently enacted a statute expressly permitting operators to drill horizontal wells across voluntary units unless expressly prohibited by the leases in the unit. In Texas, the Railroad Commission (which regulates oil and gas operations) has permitted cross-unit

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3 *See* Michael Diamond and Jim Curry, "Shale-Driven Industry Changes," 34 Energy & Min. Law. Inst. § 5.04 (2013).

4 *See* Starr Spencer, US Upstream industry relying on longer lateral drilling to boost cash flows, S&P GLOBAL, (May 21, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/oil/052121-us-upstream-industry-relying-on-longer-lateral-drilling-to-boost-cash-flows.

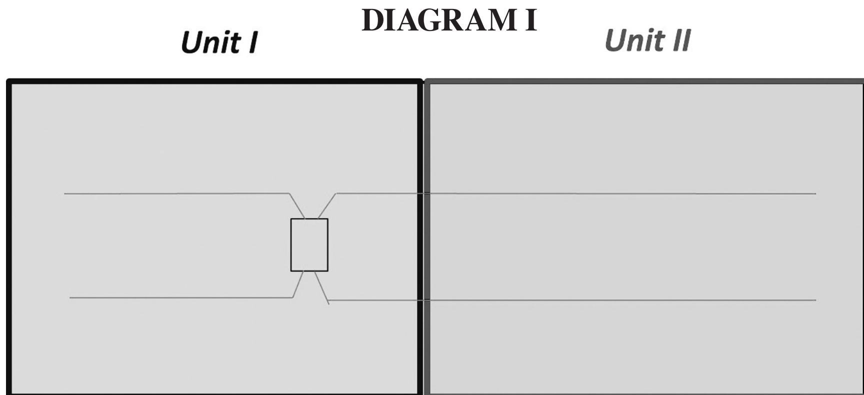
wells through an informal regulatory process. Oklahoma has a formal process for permitting cross-unit wells within its comprehensive regulatory structure.

§ 4.03. Cross-Unit Wells.

Cross-unit wells are simply lateral wellbores that cross unit boundaries into an adjacent unit or un-unitized tract.

Diagram I depicts units with cross-unit lateral wells:

DIAGRAM I



On the diagram the two western laterals from the wellpad are traditional laterals wellbores that lie entirely in Unit I. The two eastern laterals are cross-unit wells that cross from Unit I onto Unit II.

Diagram I makes immediately apparent the economic advantages of cross-unit wells. Unit I and Unit II can be fully developed with four laterals from one pad as opposed to up to eight laterals from two pads. Only one wellpad is required rather than two. Because there is only one wellpad fewer roads must be built to access the wellpad and fewer pipelines built to transport natural gas to a transmission line from the wellpad. Fewer adjacent facilities like water impoundments and tanks are required. Fewer structures like trailers must be built to house workers during drilling, completion and hydrofracturing operations. All of these efficiencies allow the oil and gas operator to reduce the cost of each barrel of oil or mcf of natural gas that it produces. The environmental advantages are also immediately apparent. Fewer wellpads, roads, pipelines and adjacent facilities reduce surface disturbance and the overall impact on the surrounding environment. Longer laterals also permit the development of oil and gas in and under environmentally sensitive areas. Essentially, cross-unit wells

are a true "win-win" for the oil and gas operator, the oil and gas owner and the surface owner (if oil and gas rights are severed form the surface).

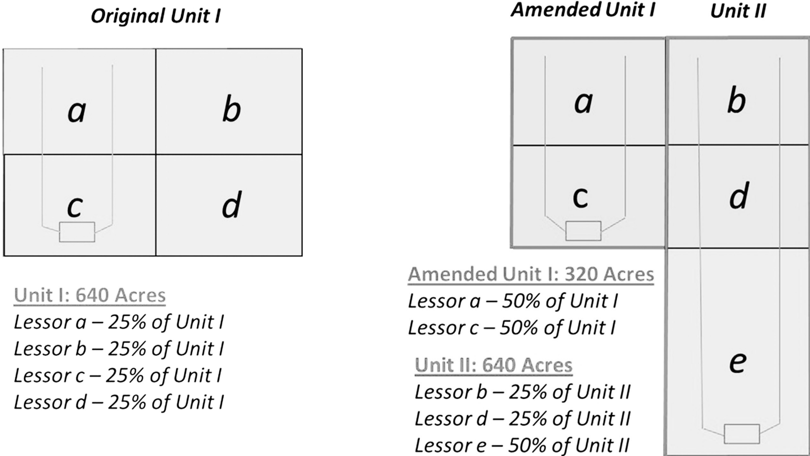
§ 4.04. Existing Methods Used to Permit Longer Wells.

The existing methods used by oil and gas operators to permit longer laterals on existing units are: 1) amending units to permit longer laterals; 2) obtaining production sharing agreements from all lessors in a unit; 3) overlapping new units with existing units; and 4) drilling allocation wells across existing units.

[1] — Amend Existing Units.

The most obvious solution for drilling on a longer lateral on a unit is to amend the unit to add additional tracts needed to drill the longer lateral. Diagram II depicts an amended unit:

DIAGRAM II



Amending a unit has intuitive appeal because at first glance it appears to be the simplest way to permit longer laterals and it works within the traditional lease-based pooling paradigm. However, there are number of practical difficulties in amending units.[5] First, the pooling clauses in all of

5 For a lengthier discussion of the difficulties in amending unit boundaries *see* Williams & Meyers, Oil & Gas Law § 980 *et seq*.

the leases must permit lessee to unilaterally amend the unit after production. If any pooling clauses do not permit this, the operator must obtain lease amendments from all of the lessors from all of those leases. Tracts in areas with a long history of oil and gas development may have dozens of owners of the oil and gas. The transaction costs of negotiating amendments with dozens or hundreds of lessors can be immense. Although the benefits of longer laterals to all stakeholders are demonstrable, some lessors undoubtedly will attempt to leverage their consent to obtain lease modifications such as higher royalties or other more advantageous terms.

In addition, amending a unit usually means increasing or decreasing the size of the unit. If the unit is increased in size, each lessor's proportionate ownership in the unit will be diluted. For example, if a lessor owns 25 percent of the acreage in a unit and the unit is doubled in size the owner now only owns 12.5 percent of the acreage in the unit. Unless production immediately doubles (which is not likely due to the time lag between amending a unit and drilling and producing the new wells), the owner will see their royalties decline (at least in the short term), making them unhappy and more likely to challenge the unit amendment, potentially with a legal claim for breach of the lease. If a unit is decreased in size, depending on the lease terms, the lessee risks losing leases on the acreage removed from the unit, since the acreage is no longer held by production from the unit. Further, amending a unit to create a new unit as depicted in Diagram II can create additional dissatisfaction among the lessors. In Diagram II, owners a and c may complain that they shared royalties with owners b and d for Unit I, but they do not get to participate in royalties from Unit II. These difficulties have led oil and gas operators to pursue other methods for permitting longer lateral wellbores.

[2] – Production Sharing Agreements.

One such alternative to an amended unit is a Production Sharing Agreement ("PSA"). A PSA is an agreement between the operator and the royalty owners in the units as to how production will be allocated among the parties. A PSA can allocate production by any agreed methodology to solve a unit boundary limitation or lease restriction in order to accommodate longer horizontal laterals. Division of royalties can be based on acreage or productive

lateral length. Some operators will proceed once a majority percentage of owners agree rather than waiting until all owners have consented. However, "majority" can be interpreted several ways. Does it mean a majority of the owners? A majority of the tracts? The owners of a majority of acreage in the unit? The primary disadvantage of PSAs is that they have the same transaction costs as obtaining lease amendments. Getting consents is time-consuming and expensive. It can be difficult or impossible to get all owners to consent when ownership is highly fractionated. Different owners may have competing interests in how the royalty is allocated. If the operator proceeds without obtaining consents from all owners, they run the risk of claims from nonconsenting owners that they have violated the terms of their leases. In the end, these difficulties make PSAs a practical solution only when ownership of oil and gas in a proposed unit is highly concentrated.

[3] – Overlapping Pooled Units.

Overlapping units share production and acreage between two or more units that the horizontal wellbore traverses. Essentially, this means unitizing the same acreage twice. The overlapped unit participates on an acreage contribution basis in all wells drilling on the newly formed unit overlapping the original unit the same as if it were a single lease. Production is allocated between units based upon the acreage contribution as opposed to allocating by lateral feet of the horizontal wellbore, thereby following typical pooling clauses of the leases with the resulting royalty formula based on surface acres. This follows the Pennsylvania rule of apportionment.[6] Diagram III illustrates an overlapping unit and the division of interest:

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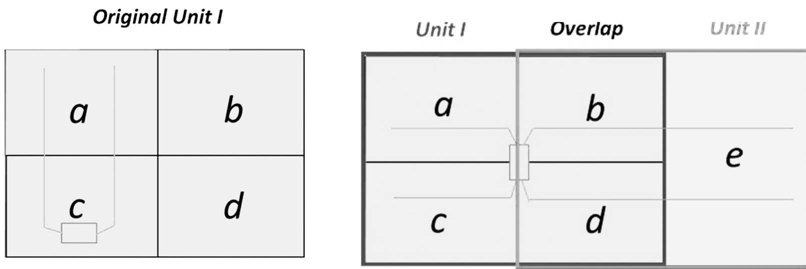
6 For the genesis of the apportionment rule in Pennsylvania see Wettengel v. Gormley, 160 Pa. 559 (1894); *see also* William O. Huie, *Apportionment of Oil and Gas Royalties*, 78 Harv. L. Rev. 1113 (1965).

DIAGRAM III



Unit I: 640 Acres
Lessor a – 25% of Unit I
Lessor b – 25% of Unit I
Lessor c – 25% of Unit I
Lessor d – 25% of Unit I

Unit II: 640 Acres
Unit I – 320 Acres, 50% of Unit II
Lessor a – 12.5% (25% of 50%)
Lessor b – 12.5% (25% of 50%)
Lessor c – 12.5% (25% of 50%)
Lessor d – 12.5% (25% of 50%)
Lessor e – 320 Acres, 50% of Unit II

Overlapping units and dividing royalties in this manner arguably lead to a fairer division of royalties than amended units because the division of interest for each unit does not change over time. In addition, all lessors in the overlapping units receive royalties from all production from the acreage.[7] Moreover, overlapping units are expressly authorized in Pennsylvania by legislation, as discussed below.[8] The primary disadvantage is the legal novelty of overlapping units. In particular there may be legal issues with dedicating the same acreage to two different units in jurisdictions that follow the Texas cross-conveyance theory of pooling.[9]

[4] – Allocation Wells.

The fourth method of drilling longer laterals across existing units is to drill "allocation" wells. An allocation well is a horizontal well that traverses the boundary between two or more leases, two or more pooled units or a combination of leases and pooled units, and for which no agreement exists

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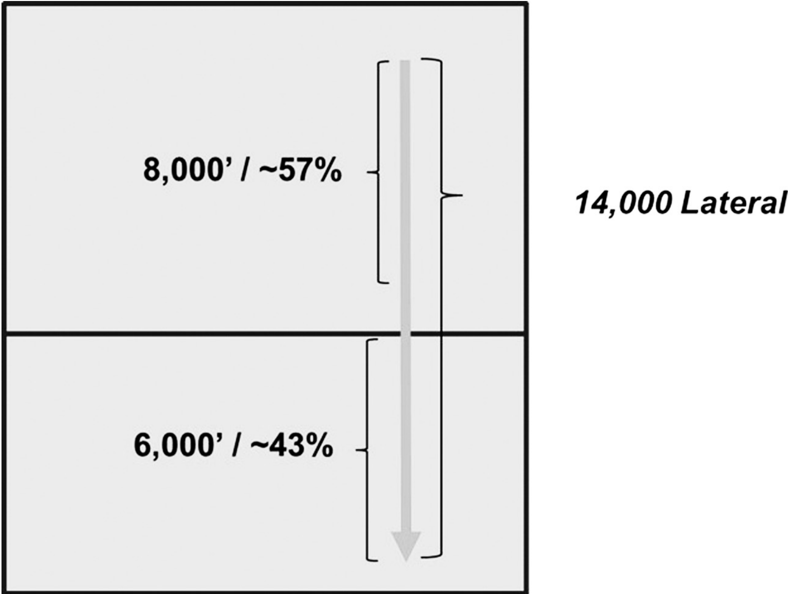
7 For a case involving a claim by royalty owners who did not receive royalties from an overlapping unit, *see* Samson Expl., LLC v. T.S. Reed Properties, Inc., 521 S.W.3d 26 (Tex. App. 2015).

8 *See* 4.05[1].

9 *See* Montgomery v. Rittensbacher, 424 S.W.2d 210, 213 (Tex. 1968).

among the royalty owners as to how production will be shared. Diagram IV shows an allocation well with production allocated to each tract or unit based on its proportion of productive wellbore lateral:

DIAGRAM IV



Allocation wells are expressly authorized in Pennsylvania by legislation and in Oklahoma by a formal regulatory process, as further discussed below.[10] While allocation wells have been permitted by the Texas Railroad Commission through an informal regulatory process, these have been subject to various legal challenges by lessors, including *Elsie Opiela et al. v. EnerVest Operating, L.L.C,* as discussed below.[11] Government-sanctioned allocation wells may well provide the best solution for permitting cross-unit wells with longer lateral lengths. Opposition has primarily arisen from lessors who want to maintain leverage by requiring lessor consent requirements.

10 *See* 4.05[3].

11 Elsie Opiela et al. v. EnerVest Operating, L.L.C., Cause No. 18-06-00153 CVK, 81st Judicial District Court of Karnes County, Texas (Filed June 2018).

§ 4.05. Laws Permitting Cross-Unit Wells.

This chapter focuses primarily on laws permitting cross-unit wells in Pennsylvania, Texas, and Oklahoma, but also notes other jurisdictions that address the same, including Louisiana and Arkansas. Each of these states takes a different approach to permitting and regulating cross-unit drilling. The Pennsylvania legislature has recently enacted a statute that establishes the authority of operators to drill cross-unit horizontal wells. Texas has taken a different approach where the Texas Railroad Commission ("RRC") issues permits under an informal regulatory practice to operators seeking to drill horizontal wells across leases and units as "allocation wells" or in accord with "production sharing agreements." Oklahoma, in contrast, has a detailed legislative scheme and formal application process before the Oklahoma Corporation Commission ("OCC") for operators seeking permission to drill cross-unit wells, provided that the well will prevent waste, protect the rights of the owners, and efficiently develop each of the affected units.

[1] – Pennsylvania.

Since 1878 when the first natural gas well was drilled in Pennsylvania, the natural gas industry has grown exponentially and provided significant economic growth in Pennsylvania in particular.[12] Growth in the industry has resulted in various statutory and regulatory changes by the Commonwealth over the years.

In 1979, Pennsylvania enacted the Guaranteed Minimum Royalty Act ("Royalty Act") specifying that leases entered into after September 18, 1979, must provide to lessors a minimum of one-eighth royalty on oil and gas removed or recovered from the property.[13] In 2013, Pennsylvania amended and retitled the Royalty Act as the Oil and Gas Lease Act, commonly known as "Act 66." Act 66 recodified the Royalty Act, imposed new reporting requirements on operators, and added sections for permitting cross-lease development of horizontal wells without specific pooling authority, division

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12 Ross H. Pifer, *What A Short, Strange Trip It's Been: Moving Forward After Five Years of Marcellus Shale Development*, 72 U. PITT. L. REV. 615, 619 (2011).

13 58 Pa. Stat. Ann. § 33 (1979).

orders, and *de minimus* payments.[14] The Apportionment section of the Act 66 provides:

> Where an operator has the right to develop multiple contiguous leases separately, the operator may develop those leases jointly by horizontal drilling unless expressly prohibited by a lease. In determining the royalty where multiple contiguous leases are developed, in the absence of an agreement by all affected royalty owners, the production shall be allocated to each lease in such proportion as the operator reasonably determines to be attributable to each lease.[15]

Essentially, Act 66 provides a statutory mechanism for horizontal drilling across leases without pooling. This provision allows operators to combine leases that are otherwise silent as to pooling rights for development by horizontal wells across contiguous leases. It is often utilized to pool older vintage leases typically signed prior to the incorporation of modern pooling clauses, permitting operators to drill horizontal wells without additional consent from the royalty owners.

Although Act 66 addressed cross-lease drilling, it did not expressly provide for horizontal drilling across separate units. However, cross-unit drilling was subsequently addressed by the Pennsylvania legislature in 2019 when it amended Act 66 by enacting "Act 85."[16] Act 85 provides:

> *(a) General rule*. If an operator has the right to drill an oil or gas well on separate units, **the operator may drill and produce a well that traverses, by horizontal drilling, more than one unit**, if:
> (1) The operator reasonably allocates production from the well to or among each unit the operator reasonably determines to be attributable to each unit. The operator may allocate production on an acreage basis for multiple units provided the allocation has a

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14 58 Pa. Stat. Ann. § 33.1, *et seq*. (2013).

15 58 Pa. Stat. Ann. § 34.1 (2013).

16 Act 85 amended the Royalty Act by adding Section 2.2 entitled "Cross-Unit Drilling for Unconventional Wells." *See* 58 Pa. Stat. Ann. § 34.2 (2019).

> reasonable correlation to the portion of the horizontal well bore in each unit. (2) The traversing well is not expressly prohibited by the terms of a lease.
>
> *(b) Location requirement*. The 330-foot location requirement in section 6 of the act of July 25, 1961 (P.L.825, No.359), known as the Oil and Gas Conservation Law, shall not apply to unit lines traversed by a conservation well.
>
> *(c) Construction*. Nothing in this subsection shall be construed to: (1) authorize an operator to drill an oil or gas well that is not subject to a valid lease or royalty agreement; and (2) automatically expand or diminish the current surface rights of an operator to include operations related to any existing unit or any well drilled between existing units. [17]
>
> (emphasis added).

Act 85 gave operators much needed guidance with respect to cross-unit wells. Unless expressly prohibited by the lease terms, Act 85 expressly permits cross-unit drilling of allocation wells across more than one unit, including overlapping units. While still in its infancy, having only been in effect since January 6, 2020,[18] it is likely that cross-unit drilling under Act 85 will become a more common practice within the Commonwealth. A recent case challenging the constitutionality of Act 85 (as well as asserting a variety of breach of contract claims) has been filed and is currently pending in the U.S. District Court, Middle District of Pennsylvania.[19]

[2] – Texas.

Although Texas has no express statutory or regulatory authority permitting horizontal drilling across lease lines absent pooling rights, an

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17 *Id*.

18 *Id*.

19 *See* Warner Valley Farm, LLC v. SWN Production Co., LLC, Mid. District of PA Case No. 4:21-CV-01079-MWB (2021).

informal regulatory process has been followed by the RRC. As a general practice, the RRC issues permits to operators so long as the operator shows a good faith claim of a right to drill on the property.[20] With respect to allocation of production, the Texas Supreme Court ruled, in *Browning Oil Co., Inc. v. Luecke*, that a lessee may drain oil and gas from neighboring tracts without the owners' consent, but must pay based upon "a determination of what production can be attributed to [each tract] with reasonable probability."[21] Two methods for permitting horizontal wells in Texas across lease lines without a voluntary pooling agreement have been followed by the RRC — allocation wells or PSA Wells.

[a] – Allocation Wells.

As discussed above, an allocation well is a horizontal well that traverses the boundary between two or more leases that have not been pooled and for which no agreement exists among the owners as to how production will be shared.22 The difference between PSA Wells (discussed below) and allocation wells is that an allocation well permit may be obtained without the operator's representation of owner's consent, provided, however that allocation wells may only incorporate tracts traversed by the wellbore.23 In 2013, the RRC approved a drilling permit for an allocation well that crossed two leases, ruling that it had authority to issue horizontal well permits across leases absent pooling.[24] Prior to *Klotzman*, the RRC had permitted approximately 100 allocation wells; since then, it has permitted thousands of allocation

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20 Magnolia Petrol. Co. v. R.R. Comm'n, 170 S.W.2d 189,191 (Tex. 1943).

21 Browning Oil Co. v. Luecke, 38 S.W.3d 625, 647 (Tex. App. – Austin 2000, pet. denied).

22 Clifton A. Squibb, *The Age of Allocation: The End of Pooling As We Know It?*, 45 TEX. TECH L. REV. 929, 930 (2013).

23 Railroad Commission of Texas, PSA Wells, Allocation Wells and Stacked Laterals, Permitting and Completion, by Lorenzo Garza and Joe Stasulli, Slide 22.

24 TEX. R.R. COMM'N, Application of EOG Resources, Inc. for its Klotzman Lease (Allocation), Well No. 1H (Status No. 744730), Eagleville (Eagle Ford-2) Field, Dewitt County, as an Allocation Well Drilled on Acreage Assigned from Two Leases, Docket No. 02-0278952 (Sept. 24, 2013) (final order) [hereinafter *Klotzman*].

wells.[25] However, this RRC decision did not fully address the ability of operators to drill cross-unit allocation wells. In 2018, Monroe Properties protested an allocation well permit application filed by Devon Energy, in which Devon sought to drill a horizontal well across tracts, some of which were previously included in different units.[26] The RRC found that Devon held leases covering the tracts, and noted that due to the 3,324 wells already permitted post-*Klotzman* (as of November 9, 2017), the RRC would continue to follow its practice of allowing allocation wells.[27] The RRC further found that "neither pooling authority nor a production sharing agreement is required to establish a good faith claim for a permit to drill an allocation well."[28] Monroe Properties subsequently sought review of the decision, and the case was later nonsuited.[29]

[b] – Production Sharing Agreement Wells.

The RRC also has a policy of granting drilling permits for wells drilled pursuant to PSAs ("PSA Well(s)"). Operators utilize PSA Wells to combine multiple pooled units that accommodate horizontal wells by entering into PSAs with royalty and working interest owners in the leases committed to each pooled unit.[30] In 2008, the RRC established a policy to grant permits for PSA Wells "when the usual criteria are met and the operator certifies that at least 65% of the working and royalty interest owners in each component

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25 *See* Complaint of Monroe Properties, Inc., et al., re: Devon Energy Production Co., L.P., N I Helped 120 (Allocation) Lease, Well No. 6H, Docket No. 08-0305330 (Dec. 18, 2017) (final order) [hereinafter *Monroe Properties* Complaint].

26 *See* Pls' Original Petition for Judicial Review, Monroe Properties, Inc., SRO Land & Minerals, L.P., and the Lee M. Stratton Living Trust, Mary Elizabeth Stratton, Trustee v. Railroad Commission of Texas, No. D-1-GN-18-001111 (Tex. Dist. filed March 2, 2018), 2018 WL 1318010, appeal dismissed.

27 *See Klotzman, supra.*

28 *See Monroe Properties* Complaint*, supra.*

29 Monroe Properties, Inc., et al. v. Railroad Commission of Texas, Cause No. D-1-GN-18-001111, 53rd Judicial District, Travis County, Texas.

30 *See* H. Phillip Whitworth & D. Davin McGinnis, *Square Pegs, Round Holes: The Application and Evolution of Traditional and Regulatory Concepts for Horizontal Wells*, 7 Tex. J. Oil, Gas & Energy L. 177, 210-213 (2012).

tract have signed the [PSA]."[31] If the operator obtains a PSA with the 65 percent approval threshold, the RRC allows the operator to treat the area covered by the PSA as a single drillsite tract. One of the challenges for operators wishing to use PSAs for cross-lease or cross-unit horizontal wells is obtaining the consent of all, or at least 65 percent, of the working interest and royalty interest owners. However, once obtained, it provides clarity as to the parties' agreement of the allocation of production.

[c] – Methods of Allocating Production.

Various methods are used to allocate production, including (1) surface acreage basis; (2) length of the lateral portion of wellbore beneath each tract; or (3) productive portion of the lateral in each tract.[32] Allocating production based on a surface acreage basis is well-known and relatively simple to compute, merely requiring a determination of the proportion of the lease acreage in the unit divided by the entire unit acreage. Alternatively, production may be based on the lateral portion of the well falling within a particular tract compared to the total lateral footage.

A third method is similar to the lateral length allocation, except that it involves allocating based on the productive portion of the well on each tract, i.e., the length of the well on each tract calculated from the first takepoint to the last takepoint. This method was addressed in *Springer Ranch v. Jones*.[33] In *Springer Ranch*, the court found that receiving royalties on all of the well and not only the production directly from the lessor's tract would not be a "utilitarian construction in light of the business activity the contract pertains to and is unreasonable, inequitable, and oppressive," finding that production should be allocated based on the producing portions of the wellbore traversing that lessor's tract.[34]

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31 *See Klotzman* at 5.

32 Doug J. Dashiell, Texas Railroad Commission Regulation of Horizontal Drilling in Texas Potential Problems and Practical Solutions at the Ernest E. Smith 36th Annual Oil, Gas & Mineral Law Institute, (April 9, 2010).

33 Springer Ranch v. Jones, 421 S. W. 3d 273 (Tex. App. - San Antonio 2013).

34 *Id*.

Cases have been filed in courts across the State of Texas regarding allocation wells and PSA Wells. One such case is *Elsie Opiela et al. v. EnerVest Operating, L.L.C.*[35] The Plaintiffs in *Opiela* allege that the operator breached the lessors' oil and gas lease by drilling an allocation well. Specifically, the Plaintiffs claimed the allocation well was not authorized by the lease, that the well commingled produced oil from another tract of land and that the operator trespassed on the subsurface of the land in question. Plaintiffs are seeking actual damages consisting of "all gross proceeds from that production attributable to the Property without deduction for operating costs." Further, Plaintiff seeks exemplary damages and a permanent injunction against Defendants from producing oil and gas from the well in question. On May 21, 2021, the District Court reversed the RRC's Order and remanded to the Commission for further proceedings, finding, *inter alia*, that the RRC erred (i) in adopting rules for allocation and Production Sharing Agreement well permits without complying with the Administrative Procedure Act, (ii) by issuing the permit in question to Magnolia (successor to EnerVest), and (iii) in finding that Magnolia showed a good faith claim of right to drill the well in question.[36] This case is currently on appeal.[37]

The RRC has, under an informal regulatory practice, permitted the drilling of horizontal wells across lease lines absent voluntary pooling. Although perhaps persuasive, these RRC decisions are only binding on the parties involved, and do not have the force and effect of law. Questions remain until a final binding decision is entered or the legislature resolves the question.

[3] – Oklahoma.

Unlike Pennsylvania and Texas, Oklahoma has express statutory and regulatory provisions addressing cross-unit drilling. Oklahoma provides for a formal application and approval process to regulate the drilling of cross-

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35 Elsie Opiela et al. v. EnerVest Operating, L.L.C., Cause No. 18-06-00153 CVK, 81st Judicial District Court of Karnes County, Texas (Filed June 2018).

36 *Id*.

37 *See* Opiela v. Railroad Commission, Case No. D-1-GN-20-000099, 53d Judicial District Court of Travis County, Texas.

unit wells. The OCC was granted the authority to regulate horizontal drilling under the 2011 Shale Reservoir Development Act, as amended ("Act").[38]

A cross-unit well, or "multiunit horizontal well" is defined as "a horizontal well in a targeted reservoir or targeted reservoirs wherein the completion interval of the well is located in more than one unit formed for the same targeted reservoir, with the well being completed in and producing from such targeted reservoir in two or more of such units."[39] Under the Act, the OCC is authorized to allow multiunit wells upon a determination that the comingling of production from one or more units is necessary to prevent waste and protect the correlative rights of the oil and gas owners.[40] Costs and proceeds from a multiunit well are allocated to the oil and gas owners in each of the affected units which are actually penetrated within the completion interval.[41]

The Act provides a detailed process for application by an operator for approval of a multiunit horizontal well. Information to be submitted includes: (i) the approximate anticipated location of the proposed cross-unit well; (ii) a map showing the location of existing wells in each affected unit and of each proposed well; and (iii) any proposed allocation factor(s) for allocating costs, production, and proceeds from each proposed well.[42] The OCC must find, based on testimony and evidence presented at a hearing, that the proposed multiunit horizontal well(s) will prevent waste, protect correlative rights, and likely lead to the full and efficient development of oil and gas production within each affected unit.[43] Ultimately, production is allocated to each affected unit based on an allocation factor approved by the OCC. The allocation factor for each unit is "determined by dividing the length of the completion interval located within the affected unit by the entire length

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[38] *See* 52 O.S. §§ 87.6-87.9 (2011), renamed the "Extended Horizontal Well Development Act" in 2017.

[39] 52 O.S. § 87.6.

[40] 52 O.S. § 87.8.

[41] *Id*.

[42] *Id*.; *see also* OAC 165:5-7-6.2.

[43] 52 O.S. § 87.8.

of the completion interval" in the well, subject to adjustment as determined by the OCC to prevent waste and adequately protect correlative rights.[44]

The Oklahoma legislative paradigm provides clarity as to an operator's right to drill cross-unit wells.

[4] – Other States with Laws Addressing Cross-Unit Wells.

[a] – Louisiana.

In Louisiana, all oil and gas units with a depth of 3000 feet or longer require a 330-foot setback from the unit or the lease lines.[45] These setbacks have resulted in large areas of a unit from which oil and gas could not be recovered. In response to these issues, the Louisiana Office of Conservation, the entity responsible for issuing drilling permits within the state, began issuing permits for cross-unit wells that could cross unit boundaries. In 2015, the Louisiana legislature enacted a statute that expressly authorized cross unit drilling.[46] In order to avoid "short units" where an operator could drill a very small portion of the lateral into another unit in order to perpetuate leases in the adjoining unit, the statute provides that no permit will be authorized if an owner in the adjacent unit objects to the drilling of the cross-unit well and the well has less than 500 feet of perforated lateral.[47] This ensures that the rights of interest owners in adjoining units are protected.

[b] – Arkansas.

Cross-unit wells are permitted in Arkansas in conformance with the Arkansas Oil and Gas Commission ("OGC") rules. The OGC is authorized to make exceptions to the rules when such exception "is likely to prevent waste or protect correlative rights of owners within the unit, or both."[48] General Rule B-43 addresses the permitting and production of cross-unit

44 *Id.*
45 *See* La. Admin Code. tit. 43, Pt XIX, § 1905.
46 *See* 43 LA.R.S. 30:9.2.
47 *Id.*
48 Ark. Code Ann. § 15-72-302(c)(1).

wells in certain unconventional gas sources.[49] The application must include, *inter alia*, detailed maps or plats, development plans, minimum perforated lateral lengths, the methods for sharing costs and proceeds, and notice to all owners.[50] Any owner given notice of the cross-unit well application may object to the approval of such application.[51] If necessary, the director may refer the application to the OGC to make a determination.[52] The Rule sets out the methodology to be used for sharing the costs and proceeds of production from one or more separately metered wells, which is generally based on allocation of acreage in the unit.[53]

§ 4.06. Conclusion.

Longer laterals extending tens of thousands of feet in horizontal wells provide clear economic and environmental advantages over conventional wells. However, existing units often do not contain sufficient acreage to drill these more efficient longer lateral wellbores. While there are various methods to obtain the contractual rights for voluntary cross-unit pooling, these are costly and time-consuming. Some of the producing states have addressed this issue by statute, by regulation, or by common regulatory practice. Cross-unit drilling creates novel issues which may continue for years to come as the concerns are brought before regulatory agencies and the courts.

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49 *See* Ark. Admin. Code 178.00.1-B-43.
50 *Id.*
51 *Id.*
52 *Id.*
53 *Id.*

Chapter 5

Tax-Free Exchanges of Energy and Mineral Properties

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§ 5.01. An Introduction to Like-Kind Exchanges.

Section 1031 can be a useful tool for energy and mineral transactions.[1] Typically, when you sell property, you recognize taxable gain or loss, measured by the difference between that property's adjusted basis[2] and the consideration received, or deemed to be received, in the sale.[3] Section 1031 provides an exception to this rule in certain circumstances, which can reduce the seller's immediate tax cost, thereby facilitating the overall transaction.

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1 All "Section" references in this article are to the Internal Revenue Code of 1986, as amended ("I.R.C.") or to the U.S. Treasury Department regulations promulgated thereunder ("Treasury Regulations" or "Treas. Reg.").

2 The "adjusted basis" for determining the gain or loss from the sale or other disposition of property generally is the cost of the property under I.R.C. § 1012 as adjusted under I.R.C. § 1016 for capital improvements and depreciation or depletion.

3 I.R.C. § 1001(a). The consideration received, or deemed to be received, in a transaction for federal income tax purposes is called the "amount realized." Generally, if a seller transfers property subject to a liability, the amount of that liability will be included in the seller's amount realized. Treas. Reg. § 1.1001-2(a). *See also* Crane v. Comm'r, 331 U.S. 1, 6-10 (1947). Liability relief implicates special rules in the like-kind exchange context.

The basic rule is as follows: a taxpayer will not recognize gain or loss on the sale of real property held for productive use in a trade or business or for investment (the "relinquished property"), for other real property of a like-kind that is to be held for productive use in a trade or business or for investment (the "replacement property").[4] The principal justification for nonrecognition in a like-kind exchange is that the taxpayer continues invest in the same kind of property, and has not cashed out of their investment. The term "like-kind" has a relatively broad meaning. Recent Treasury Regulations (discussed below) confirm that the definition of "real property" is broad. Almost any domestic real property interest will be of "like-kind" to another domestic real property interest, so long as one of the interests is not of limited duration.[5] For example (subject to issues of "recapture," discussed below), based on existing guidance, a taxpayer could exchange: (i) mineral properties for a hotel or apartment complex;[6] (ii) improved or unimproved real estate for an interest in overriding oil and gas royalties;[7] (iii) a working interest in an oil and gas lease for an improved ranch;[8] (iv) a coal mine subject to coal supply

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4 I.R.C. § 1031(a).

5 An oil and gas interest, although an interest in real property, is not of "like-kind" to a fee simple interest in real property if the oil and gas interest is of limited duration. Fleming v. Comm'r, 24 T.C. 818 (1955) (holding that an interest in oil and gas that terminated based on the dollar value of oil and gas produced was a "limited" right that could not be of "like-kind" to a fee interest, regardless of state law classification), *aff'd by* Comm'r v. P.G. Lake, Inc., 356 U.S. 260, 268 (1958). In contrast, a working interest or overriding royalty interest in an oil and gas lease that extends to the exhaustion of the mineral interest is "like-kind" to a fee simple interest in real property. The fact that a lease is in its primary term should not affect this analysis, so long as the secondary term is indefinite (i.e., based on operations, drilling and/or production of oil and gas, without a limit with respect to the amount of production).

6 *See* Crichton v. Comm'r, 112 F.2d 181, 182 (5th Cir. 1941) (holding that mineral rights were of like kind to undivided interests in a hotel).

7 *See* Rev. Rul. 73-428, 1973-2 C.B. 303 (ruling that a royalty interest is an interest in real property for purposes of federal income tax law) and Rev. Rul. 72-117, 1972-1 C.B. 226 (ruling that an overriding oil and gas royalty is of like-kind to improved real estate). *See also* Treas. Reg. § 1.1031(a)-1(c) ("The fact that any real estate involved is improved or unimproved is not material [to the like-kind inquiry].").

8 *See* Rev. Rul. 68, 1968-1 C.B. 352 (ruling that a working interest in an oil and gas lease is of like kind to a fee interest in improved ranch land).

contracts for a fee interest in real property subject to a perpetual conservation easement;[9] or (v) any combination of the above.

The term "tax-free exchange" is a bit of a misnomer. Assuming that no taxable gain (also called "boot") is recognized in an exchange, the taxpayer's basis in the relinquished property will carry over as their initial basis in the replacement property (as opposed to having an initial basis equal to cost).[10] Therefore, the taxable gain in reality is deferred until the eventual sale of the replacement property.[11] To obtain complete deferral of federal income tax under Section 1031, the exchanging party must: (i) reinvest *all* of the cash proceeds from the sale of the relinquished property; (ii) obtain equal or greater financing on the replacement property than was paid off or assumed on the relinquished property;[12] and (iii) receive nothing in the exchange except for like-kind replacement property.[13] In some cases, sale or receipt of non-qualifying cash or property (e.g., incidental personal property) simply creates "boot" equal to the value of such cash or property.[14] In other cases, the sale or receipt of non-qualifying cash or property implicates the "actual or constructive receipt" rules applicable to non-simultaneous like-kind exchanges (discussed below) and therefore disqualifies the *entire* exchange.[15]

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9 *See* Peabody Natural Res. Co. v. Comm'r, 126 T.C. 261 (2006) (holding that a gold mine is of like-kind to a coal mine subject to coal supply contracts) and I.R.S. Priv. Ltr. Rul. 200203042 (Jan. 18, 2002) (ruling that a perpetual conservation easement is an interest in real property that may be of like-kind to a fee interest or other perpetual interest in real property).

10 I.R.C. § 1031(d).

11 Sometimes this tax is deferred indefinitely. For example, the taxpayer may dispose of the replacement property in another like-kind exchange or, if the taxpayer is an individual, he or she may die holding the replacement property, stepping up the basis of the property to fair market value in the hands of his or her heirs. *See* I.R.C. § 1014.

12 A shortfall in replacement property debt may be made up by additional equity in the replacement property. *See* Treas. Reg. § 1.1031(j)-1(b)(2)(ii)(A).

13 I.R.C. § 1031(c).

14 Treas. Reg. § 1.1031(k)-1(g)(7).

15 Treas. Reg. § 1.1031(k)-1(g)(6).

A like-kind exchange need not be simultaneous.[16] In fact, most are not. The Treasury Regulations permit the use of a "qualified intermediary," who is treated as the purchaser and the seller of the relinquished and replacement properties, respectively, without actually taking title to such properties.[17] A qualified intermediary generally can be any person *except* for the taxpayer or a disqualified affiliate or agent of the taxpayer (such as the taxpayer's accountant, attorney or real estate agent).[18] Financial institutions, title insurance companies and escrow companies that provide only "routine" financial, title insurance, escrow or trust services to the taxpayer are not disqualified agents.[19] The taxpayer and the qualified intermediary generally will enter into an "exchange agreement," pursuant to which the qualified intermediary agrees take assignment of the taxpayer's rights (but not its obligations) under the relinquished property sale agreement. The qualified intermediary receives the cash proceeds from that sale directly from the purchaser at the closing and holds such "exchange funds" (generally, in escrow or trust) during the relevant exchange period.

In a forward non-simultaneous like-kind exchange, the "exchange period" begins on the date that the taxpayer transfers the relinquished property and spans for not more than 180 days.[20] In the first 45 days of the exchange period, the taxpayer must identify one or more replacement properties by sending a signed notice to the qualified intermediary. The taxpayer may identify three potential replacement properties without regard to their fair market value or may identify any number of replacement properties so long as the aggregate fair market value of the identified replacement properties does not exceed 200 percent of the fair market value of the relinquished property. [21] Because the fair market value of potential replacement properties is not always certain

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16 I.R.C. § 1031(a)(3).

17 Treas. Reg. § 1.1031(k)-1(g)(4)(i).

18 Treas. Reg. § 1.1031(k)-1(k).

19 Treas. Reg. § 1.1031(k)-1(k)(2)(ii).

20 Treas. Reg. § 1.1031(k)-1(b)(2)(ii).

21 Treas. Reg. § 1.1031(k)-1(c).

(and the Internal Revenue Service could second-guess any assumed values), taxpayers using the 200 percent method ideally should leave a substantial cushion (i.e., identify less than 200 percent by a reasonable margin). Each replacement property must be received before the end of the exchange period and must be substantially the same as the property identified.[22] Generally, before the taxpayer acquires a replacement property, the taxpayer assigns its rights under the purchase contract to the qualified intermediary, and the qualified intermediary (stepping into the shoes of the taxpayer) authorizes disbursement of exchange funds directly to the seller of the replacement property at closing. A forward non-simultaneous exchange also may be structured as an "improvements" or "build-to-suit" exchange if the qualified intermediary (or an LLC wholly owned by the qualified intermediary) actually takes title to, and constructs improvements on, the replacement property in a manner similar to an exchange accommodation titleholder ("EAT"), discussed next.[23]

A taxpayer may acquire one or more replacement properties *before* selling the relinquished property, in a "reverse" or "parking" like-kind exchange. For example, suppose the taxpayer needs to construct substantial improvements on the replacement property in order to maximize their deferral under Section 1031. Such a taxpayer may consider a "parking" exchange under Rev. Proc. 2007-37 so that the "exchange period" begins when they acquire the replacement property (rather than when they sell their relinquished property) and their time to improve the property spans the full 180 days, with 45 days to identify the *relinquished* property.[24] Under Rev.

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22 Section 1.1031(k)-1(d).

23 Under this structure, it is much more common for the replacement property to be held by a sole purpose LLC that is wholly owned by the qualified intermediary and disregarded as an entity separate from the qualified intermediary for income tax purposes. The taxpayer's acquisition of the "replacement property" then may be accomplished through a transfer of 100% of the membership interests in such disregarded entity.

24 I.R.S. Rev. Proc. 2000-37, 2000-40 I.R.B 308. Taxpayers who need longer than 180 days to improve the replacement property may consider a "non-safe harbor" parking arrangement. *See* Bartell v. Comm'r, 147 T.C. 5 (2016). Such non-safe harbor arrangements

Proc. 2007-37, the taxpayer transfers its replacement property to an unrelated EAT through its qualified intermediary. The requirements for serving as an EAT are similar to the requirements for serving as a qualified intermediary (described above). Indeed, the qualified intermediary generally may act as the EAT, or may be the sole owner of the EAT, so long as the qualified intermediary is not an S corporation or a tax partnership with disqualified owners.[25] Under Rev. Proc. 2007-37, the taxpayer and the EAT must enter into a written agreement that includes specific language and evidences a bona fide intent to effect a like-kind exchange.[26] The EAT must hold legal title to the property (either directly or through a sole purpose LLC that is wholly owned by the EAT),[27] but in all practical respects, the taxpayer may control the property. For example, the taxpayer may advance funds to the EAT, indemnify the EAT against operating costs, cause the EAT to lease the property to the taxpayer, manage the replacement property and develop the property. The taxpayer ultimately purchases the replacement property (or the entire membership interest of the sole purpose LLC that holds title to the replacement property) using exchange funds disbursed by the qualified intermediary.[28]

Critically, in *any* non-simultaneous exchange, the taxpayer must not be in "actual or constructive receipt" of proceeds from the relinquished property to be applied to the purchase of replacement property (i.e., the exchange funds) at any time before the close of the exchange.[29] Accordingly, the qualified trust agreement, escrow agreement and/or exchange agreement between the taxpayer and the qualified intermediary and/or other exchange facilitators

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are substantially riskier (from both a tax and economic perspective) and require careful oversight of an experienced tax practitioner.

25 *See* Rev. Proc. 2000-37, §§ 4.02(1), 4.03(1).

26 Rev. Proc. 2000-37, § 4.03(1).

27 *See supra* note 23.

28 Rev. Proc. 2000-37, § 4.03.

29 Treas. Reg. § 1.1031(k)-1(f)(1).

must limit the taxpayer's rights to "receive, pledge, borrow or otherwise obtain the benefit of" exchange funds during the relevant exchange period.[30]

§ 5.02. Issues Specific to Energy and Mineral Exchanges.

[1] – "Real Property" Requirement.

In 2018, the Tax Cuts and Jobs Act amended Section 1031 to disqualify exchanges of personal property starting in 2018.[31] In December of 2020, the Treasury Department published final Treasury Regulations that provide welcome clarity regarding the scope of "real property" for this purpose.[32] Prior to the issuance of these Treasury Regulations, the applicable analytical framework was somewhat muddy. In the energy and mineral context, courts often used state law to determine whether an interest is "real property" for purposes of Section 1031.[33] Other, non-binding Internal Revenue Service guidance simply provided that state law "must be considered."[34] For example, a relatively recent Chief Counsel Advice ("CCA") memorandum advised that state law classifications are relevant, but ruled that a steam turbine—which applicable state law classified as real property—was not real property for like-kind exchange purposes.[35] Several early revenue rulings held that state law is not relevant in determining whether an oil and gas interest qualifies as "real property" for purposes of Section 1031.[36] The fact that state law sometimes is unclear or inconsistent further muddies the analysis.[37]

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30 Treas. Reg. 1.1031(k)-1(g)(6).

31 Section 13303 of Pub. L. No. 115-97, 131 Stat. 2054 (2017) (the legislation received its colloquial title, the "Tax Cuts and Jobs Act," through incorporation of prior drafts and not explicit congressional designation).

32 *See* T.D. 9935, 26 CFR Part 1 (12/02/2020).

33 *See*, e.g., Crichton v. Comm'r, 112 F.2d 181, 182 (5th Cir. 1941) and Peabody Natural Res. Co. v. Comm'r, 126 T.C. 261 (2006).

34 I.R.S. Field Advice Memorandum 20044101F (July 29, 2004).

35 CCA Memo. 201238027 (Sept. 21, 2012).

36 *See*, e.g., Rev. Rul. 68-226, 1968-1 C.B. 362; Rev. Rul. 68-331, 1968-1 C.B. 352; Rev. Rul. 72-117, 1972-1 C.B. 226; Rev. Rul. 73-428, 1973-2 C.B. 303.

37 *See* generally 1 Williams & Meyers, Oil and Gas Law § 204 (LexisNexis 2021) (surveying the classification of oil and gas interests among the fifty states and highlighting

Fortunately, the new Treasury Regulations provide a "heads you win, tails you win" framework that weaves together the existing body of law. Property is classified as real property for purposes of Section 1031 if the property is (i) classified as real property for state law purposes (with certain exceptions, discussed below), (ii) specifically listed as real property in the Treasury Regulations *or* (iii) considered real property based on all the facts and circumstances under the various factors provided in the Treasury Regulations.[38] In other words, most all "real property" under state law will be real property for like-kind exchange purposes. However, if the interest is treated as personal property for state law purposes (or if the state law is not clear), then the interest still may be "real property" for like-kind exchange purposes if it is specified in the Treasury Regulations or otherwise satisfies the facts-and-circumstances test.

Assets specifically included in the definition of "real property," regardless of their classification under state or local law, include (i) power generation or transmission facilities, (ii) oil and gas pipelines, (iii) offshore platforms, derricks, oil and gas storage tanks, (iv) unsevered natural products of land, including mines, wells and other natural deposits and (v) co-ownership interests, leasehold interests, easements, options to acquire real property, land development rights and licenses or permits to use real property.[39] With regard to intangible assets, the Treasury Regulations clarify that "interests are real property for purposes of Section 1031 . . . if the intangible asset derives its value from real property or an interest in real property and is inseparable from that real property or interest in real property."[40] This standard seems to confirm the well-established rule that overriding royalty interests are real property for like-kind exchange purposes, regardless of

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that royalty interests, for example, are viewed as personal property in Ohio and real property in Pennsylvania).

38 Treas. Reg. § 1.1031(a)-3.

39 Treas. Reg. §§ 1.1031(a)-3(a)(1), -3(a)(2)(ii)(C), -3(a)(5).

40 Treas. Reg. § 1.1031(a)-3(a)(5)(i).

state law classification.[41] With regard to tangible improvements, the facts-and-circumstances test focuses whether the improvement is "inherently permanent," assessing the damage, time and expense associated with removal.[42]

As noted above, certain categories of intangible property interests are always "personal property" for like-kind exchange purposes, regardless of state-law classification. These categories narrowly include (i) securities and evidences of indebtedness;[43] (ii) interests in a tax partnership (other than a tax partnership that has in effect a valid "opt out" election, discussed below) and (iii) interests in a trust (other than interests in a disregarded "grantor trust").[44] Oil and gas interests held through "publicly traded royalty trusts" likely are not real property. Certain oil and gas "production payments" are treated as indebtedness for federal income tax purposes and likely are excluded from the scope of "real property" by virtue of this rule.[45] Note that not all real property is "of like kind" to other real property. For example, if a production payment is an interest in real property, but may not be "of like kind" to a fee interest or other perpetual interest in real property by virtue of its limited duration.[46]

Certain replacement properties may come with relatively substantial amounts of personal property related to the acquired business operations. For example, most transfers of an operating interest in a producing well

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41 Rev. Rul. 72-117, 1972-1 C.B. 226.

42 Treas. Reg. § 1.1031(a)-3(a)(2)(ii)(C).

43 For this purpose, equity interests in a disregarded entity (e.g., a single-member LLC) will not be treated as "securities." The taxpayer is treated as selling or acquiring the assets of the disregarded entity directly.

44 Grantor trusts (including "Delaware statutory trusts" meeting certain requirements) are disregarded entities for federal income tax purposes. Rev. Rul. 2004-86, 2004-2 C.B. 191.

45 If a "production payment" is not excluded from the scope of real property by virtue of being classified as "indebtedness for federal income tax purposes," then it may be excluded because it does not "derive its value from real property or an interest in real property." Treas. Reg. § 1.1031(a)-3(a)(5)(i).

46 *See Fleming*, *supra* note 5.

will involve the transfer of the equipment used to operate the well. In a non-simultaneous like-kind exchange, the worst-case scenario is that the non-qualifying property jeopardizes the *entire* exchange under Section 1.1031-1(g)(6). A taxpayer may avoid this "worst-case scenario" one of two ways. First, they may establish that (i) the personal property has an aggregate fair market value of not more than 15 percent of the value of the replacement real property and (ii) such property "typically" is transferred along with the real property in standard commercial transactions.[47] This first approach is not ideal because, among other things, "typical" commercial practice is not always clear. Additionally, under the first approach, the value of the replacement property is taxable "boot," eroding the tax deferral feature of the like-kind exchange. The second approach is to carve out such personal property from the assignment of contract rights to the qualified intermediary, and to advance separate funds for such property directly to the applicable seller. Note that, under either approach, it is ideal to include an allocation of the purchase price among the assets in the relevant purchase agreement.

[2] – Accounting for Natural Resource Recapture Property.

Energy and mineral interests raise special recapture issues. Upon a taxable disposition, certain energy-specific costs are "recaptured" as ordinary income, to the extent of realized gain.[48] These costs include prior intangible drilling and development costs, mineral development costs, mining exploration costs and depletion deductions that reduced the property's basis.[49] In a like-kind exchange, deferral of such recapture income is available, but *only* to the extent that the taxpayer acquires "natural resources recapture property" as replacement property.[50] Therefore — although almost any real property is of "like-kind" to energy and mineral interests (including hotels and ranches) — the acquisition of such properties will not defer Section 1254

47 Treas. Reg. § 1.1031(k)-1(g)(7)(iii).

48 *Id*.

49 Treas. Reg. § 1.1254-1(a).

50 Treas. Reg. § 1.1254-2(d).

recapture income. In certain circumstances, a like-kind exchange may not be economically feasible for the taxpayer if they cannot acquire qualifying "natural resource recapture property" — i.e., property to which such energy-specific costs are "properly chargeable."[51]

What if the taxpayer *intends* to incur intangible drilling and development costs, or other such costs, with respect to the replacement property, but the property is undeveloped at the time of the exchange? Based on the "properly chargeable" language in Section 1254, it seems possible that such property qualifies as "natural resource recapture property"; however, the answer is not clear. One suggestion is to structure the like-kind exchange as a forward "build-to-suit" or "parking" arrangement (described above) so that the qualified intermediary or EAT can incur and capitalize amount of qualifying costs during the exchange period.

Interestingly, in the oil and gas context, there may be a planning opportunity for lessees who intend to sell their entire interest in an oil and gas lease (including the "deep rights"), but have only taken depletion deductions attributable to production in shallow zones. Under Section 1.1254-1(c)(3)(ii), upon the transfer of a portion of a natural resource recapture property (other than an undivided interest), a taxpayer may treat Section 1254 costs as not relating to the transferred portion if the transferred portion does not include any part of any deposit with respect to which the section 1254 (i.e., production) costs were incurred. If the lessee uses a separate qualified intermediary for the "deep rights" exchange, it seems that the exchange should be treated as a separate transfer of "portion" of the natural resource recapture property, potentially cleansing such exchange of the "Section 1254 recapture" issue.

[3] – Retained Economic Interests.

Section 1031 only applies to *sales* of real property. For federal income tax purposes, when a seller retains an economic interest in the property, the transaction may be treated as a lease (or a sub-lease), rather than a sale. If

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51 I.R.C. § 1254(a).

the transaction is recast as a lease or a sub-lease, any up-front consideration is ordinary income (i.e., a lease bonus) that is not eligible for deferral under Section 1031.

The Tax Court's analysis in *Crooks v. Comm'r*, 92 T.C. 816 (1989), is instructive. In a transaction intended to be treated as a simultaneous like-kind exchange, the Crooks family sold the mineral rights underlying their farm in exchange for four other farm properties. In the same transaction, the Crooks retained a royalty interest in all oil and gas produced from the minerals under their farm.[52] Because of the Crooks retained an indefinite economic interest in the minerals, the Tax Court recast the transaction as a lease and the farm properties received by the Crooks were a taxable "lease bonus" for federal income tax purposes.[53] Similarly, a transfer of an oil and gas lease with the retention of a non-operating interest (e.g., an overriding royalty interest) with a life coextensive with the lease will be a "sublease" for federal income tax purposes. This analysis applies on a property-by-property basis.[54] Therefore, had the Crooks sold the mineral interests underlying two farms, retaining a royalty interest with respect to only one farm, they would have been treated as leasing one interest and selling the other.

For a seller who wants to obtain "sale or exchange" treatment, there are certain structuring alternatives that may address this "retained economic interest" problem. One alternative is to transfer the would-be retained interest (*e.g.*, the overriding royalty interest) to a third party prior to, or in connection with, the transfer of the underlying working interest.[55] Ideally,

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52 Crooks v. Comm'r, 92 T.C. 816, 817-18 (1989).

53 *Id*. at 818-19 (citing Burnet v. Harmel, 287 U.S. 103 (1932) for the proposition that, "[w]hen a mineral interest is assigned for a lump-sum cash consideration and the assignor retains a right to receive a specified percentage of all oil and gas produced for the economic life of the mineral deposit, the transaction is a lease and payments received under such lease are ordinary income.").

54 Cullen v. Comm'r, 118 F.2d 651, 653 (5th Cir. 1941).

55 *See* I.R.S. Field Service Advice 1999-819, Vaugh #223 (finding "sale or exchange" treatment where the taxpayer set up a trust for his children, and transferred an overriding royalty interest to the trust, in connection with the "same overall plan" of selling the underlying working interests to a third party).

the taxpayer would carve out the overriding royalty interest and transfer it to a third party well in advance of the working interest sale. The third party should intend to hold its overriding royalty interest indefinitely. Because the Internal Revenue Service may challenge the substance of such a transaction, the taxpayer should be able to articulate a valid business or estate planning reason for bifurcating the interest as part of the sale.

Another approach to addressing the "retained economic interest" problem is to restructure the interest to qualify as a "production payment."[56] Under Section 636(b), a production payment that is created and "retained" on the sale of a mineral property generally is treated as indebtedness (and not a royalty) so long as the economic life of the production payment is shorter than the economic life of the underlying mineral property.[57] Economic lives are determined at the time the right is created. A right has an economic life shorter than that of the underlying mineral property only if the right is not "reasonably expected" to extend in "substantial amounts" over the entire productive life of the mineral property.

Courts have not articulated a bright-line test for determining when it is reasonably expected that the economic life of the right will not extend in substantial amounts over the entire productive life of the burdened property.[58] According to Rev. Proc. 97-55,[59] the Internal Revenue Service generally will issue an advance ruling that a right to minerals in place constitutes a production payment under all of four conditions:

- The right is an economic interest in a mineral in place as defined in Reg. 1.611-1(b) without regard to the application of Section 636;
- The right is limited by a specified dollar amount, a specified quantum of mineral, or a specified period of time;

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56 *See*, e.g., *Cullen*, 118 F.2d at 653. *See also* I.R.S. Priv. Ltr. Rul. 9437006 (Sept. 16, 1994) (sale of royalty interests subject to retained production payments respected as a "sale" of the interests for federal income tax purposes).

57 Treas. Reg. § 1.636-1(a)(1)(I).

58 *See*, e.g., *Yates v. Comm'r*, 924 F.2d 967, 970 (10th Cir. 1991) ("Some reasonable degree of certainty, but less than absolute, is . . . required.").

59 1997-2 CB 582.

- It is reasonably expected, at the time the right is created, that it will terminate upon the production of not more than 90% of the reserves then known to exist; and
- The present value of the production expected to remain after the right terminates is 5% or more of the present value of the entire burdened property (determined at the time the right is created).

Because a production payment is, by definition, less than a retained economic interest that extends for the life of the underlying mineral property, a seller pursuing this alternative may negotiate an increase in other consideration in the transaction.

[4] – Tax Partnership Considerations.

Tax partnerships present complex issues under Section 1031. As noted above, interests in a tax partnership are *not* eligible for like-kind exchange treatment. If the relinquished property is held through a tax partnership, the partners have a choice: (i) they can cause the partnership *itself* to engage a qualified intermediary and effect the like-kind exchange or (ii) they can "break up" the partnership, through deemed or actual liquidating distributions, allowing some partners to "cash out" and go their own way.

The definition of a "tax partnership" is relatively broad and does not follow state-law classifications. Tax partnerships include not only state-law partnerships and multi-member LLCs, but also informal, *non-juridical* contractual arrangements and joint undertakings (i.e., "groups, pools and joint ventures") that carry on a business or other operation for profit.[60] Unincorporated extraction ventures conducted through a joint operating agreement (or "JOA") often fall within the ambit of this "tax partnership"

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60 I.R.C. § 761(a). *See also* Treas. Reg. § 301.7701-1(a)(2) ("A joint venture or other contractual arrangement may create a separate entity for federal tax purposes if the participants carry on a trade, business, financial operation, or venture and divide the profits therefrom. . . . a joint undertaking merely to share expenses does not create a separate entity for federal tax purposes. . . . Similarly, mere co-ownership of property that is maintained, kept in repair, and rented or leased does not constitute a separate entity for federal tax purposes.").

definition, but may be able to *elect out* of such status under Section 761(a).[61] The election out is only available "where the participants in the joint production, extraction, or use of property —

> (i) Own the property as co-owners, either in fee or under lease or other form of contract granting operating rights,
>
> (ii) Reserve the right separately to take in kind or dispose of their shares of any property produced, extracted, or used, and
>
> (iii) Do not jointly sell services or the property produced or extracted, although each separate participant may delegate authority to sell his share of the property produced or extracted for the time being for his account, but not for a period of time in excess of the minimum needs of the industry, and in no event for more than one year."[62]

If the participants are eligible to "elect out" of tax partnership treatment, but have not previously done so, the election will effect a deemed distribution of the underling property to the "partners" in complete liquidation of the existing tax partnership. The deemed distribution will be effective as of the beginning of the relevant tax year. Such liquidating distributions generally are tax-free.[63] There is a theoretical risk that the deemed distribution of properties followed by a like-kind exchange will violate the technical "holding" requirements of the exchange.[64] In reality, this risk seems

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61 Treas. Reg. § 1.761-2(a)(3). Although the election has historically been availed of primarily by oil and gas or mineral extraction ventures, it is available to other types of production ventures as well. *See,* e.g., Rev. Rul. 68-344, 1968-1 CB 569 (co-owned power generating facilities).

62 *Id*.

63 If, within the seven-year period prior to the deemed liquidation of the partnership, one or more of the partners contributed property to the tax partnership with "built-in gain," then some or all of that "built-in gain" may be recognized by such partner to the extent that the partner receives "other property" in the liquidation. *See* I.R.C. § 737.

64 *See* Rev. Rul. 77-337, 1977-2 CB 305 (actual liquidation of a wholly owned corporation immediately prior to the exchange violates the "held for" requirement for relinquished property).

insubstantial given the landscape of existing case law and statutory mechanics of Section 461(a).[65] In certain cases, the "election out" may not be available because the real property interests are held through an LLC or other entity for financing reasons. Those cases may warrant an actual (as opposed to a deemed) distribution of the properties, followed by an election out of Section 761(a). This structure seems possible, so long as the parties take care to respect the formalities of the liquidation and sale.[66] If the parties cannot agree to the economic requirements of Section 761(a) (e.g., equal sharing of profits) or are otherwise unable to elect out of tax partnership treatment, other structures are available; however, these structures may produce less desirable economic results.

On the "replacement property" side of the like-kind exchange, the Internal Revenue Service may challenge a contribution of such property to a tax partnership immediately after the like-kind exchange.[67] Historically, such challenges have not been successful, particularly when the contributing taxpayer continues to exercise substantial control over the property.[68]

§ 5.03. Conclusion.

Section 1031 can facilitate energy and mineral transactions by reducing the immediate tax costs of the deal. Careful structuring and drafting often can address issues related to the receipt of "boot" or "non-like kind property" in an exchange. For example, in any non-simultaneous exchange, the parties should

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65 *See* Bolker v. Comm'r, 81 T.C. 782, aff'd 760 F.2d 1039 (9th Cir. 1985) (upholding a sequential tax-free corporate liquidation and exchange) and Mason v. Comm'r, T.C. Memo. 1988-273, *aff'd* 880 F.2d 420 (11th Cir. 1989) (upholding a partnership dissolution and actual distribution of tenant-in-common interests immediately followed by an exchange). The application of these authorities seems stronger in the context of a deemed liquidation under Section 461(a).

66 For a cautionary tale, see Chase v. Comm'r, 92 T.C. 874 (1989).

67 *See* Rev. Rul. 77-337, 1977-2 C.B. 305 (contribution of replacement property to a wholly owned corporation immediately after the exchange violates the "held for" requirement for replacement property).

68 *See* Magneson v. Comm'r, 753 F.2d 1490 (9th Cir. 1985) (upholding a same-day exchange of tenant in common interests by multiple co-owners and contribution to a general partnership).

review the transactional closing statements to ensure conformity with Section 1.1031(k)-1(g)(7). The parties also should consider contractual purchase price allocations. Careful planning also may address hairy issues related to retained economic interests, recapture property and tax partnerships.

Chapter 6

45Q Carbon Sequestration Tax Credit Summary

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§ 6.01. Introduction.

In February of 2018, Congress enacted and the President signed into law the Bipartisan Budget Act of 2018.[1] Section 41119 of that law included provisions to amend § 45Q of the Internal Revenue Code[2], Credit for Carbon Dioxide Sequestration. These modifications were designed to enhance the existing tax incentive for carbon capture, utilization, and storage (CCUS). This paper is designed to summarize the original 45Q tax credit and the modifications enacted in 2018 and discuss how these changes could affect deployment of CCUS technology. This is accomplished by providing a summary and historical context of the original 45Q statute, a summary of the new 45Q statute and its potential impacts on projects, a discussion of regulatory issues that must be addressed by the Internal Revenue Service (IRS) and Treasury Department (Treasury), overviews of potential project structures and non-tax barriers to project development, and next steps for program implementation and in the IRS process.

§ 6.02. Summary of the Original § 45Q Tax Credit.

Section 45Q was originally enacted as part of the Energy Improvement and Extension Act of 2008[3] and amended by the American Recovery and Reinvestment Act of 2009, and was a policy intended to incentivize the construction and deployment of carbon capture and sequestration (CCS) projects. The original § 45Q provides a credit for carbon dioxide (CO_2) sequestration and is available to taxpayers that capture qualified CO_2 at a qualified facility and dispose of the CO_2 in secure geological storage.

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1 P.L. 115-123.
2 26 U.S.C.A. § 45Q (2020).
3 P.L. 110-343.

[1] — Value of the Original Credit.

1. Twenty dollars ($23.82 in 2020 as adjusted for inflation) per metric ton for qualified CO_2 that is captured and disposed of in secure geological storage or
2. Ten dollars ($11.91 in 2020 as adjusted for inflation) per metric ton for qualified CO_2 that is captured and used as a tertiary injectant in a qualified EOR project and disposed of in secure geological storage.

[2] — Qualified Carbon Dioxide.

Qualified CO_2 was defined as CO_2 captured from an industrial source that would otherwise have been released as an industrial emission, was measured at the source of capture, and verified at the point of disposal or injection. In order to qualify under the originally enacted program, an industrial facility must have captured and sequestered a minimum of 500,000 tons of qualified CO_2 during the taxable year. In order to reduce the cost to the federal government of the original tax credit, it was capped, and will expire when tax credits for 75 million metric tons of sequestered CO_2 have been claimed. Under IRS Notice 2009-83,[4] taxpayers claiming the 45Q credit are required to file an annual report (separate from their tax return) containing the following information:

1. The name, address, and taxpayer identification number of the reporting taxpayer, and all parties with which the taxpayer contractually ensures the secure geological storage of the CO_2;
2. The name and location of the qualified facilities at which the CO_2 was captured;
3. The amounts (in metric tons) of qualified CO_2 for the taxable year that has been taken into account for purposes of claiming the § 45Q credit; and

4 I.R.S. Notice 2009-83, 2009-44 I.R.B. 588.

4. Any changes in the information included in prior annual reports submitted under section 6.01 of this notice, including adjustments to the amount (in metric tons) of qualified CO_2 taken into account for purposes of the § 45Q credit in prior taxable years.

For a calendar year taxpayer, these reports are due on June 30th for taxpayer who files their return on the due date for that return or December 31st for a taxpayer who files on the extended due date. Every year the IRS publishes a notice that includes the annual inflation adjusted tax credit rates and the number of tons that had been captured as reported through the date of the notice. According to the notice released in 2018, credits had been taken for about 60 million metric tons of sequestered CO_2. While the annual reports should indicate if the CO_2 was sequestered for EOR or permanent storage without EOR, the IRS only publishes the total metric tons on which credits have been claimed.

The 45Q credit operates like a production tax credit (PTC), such that the taxpayer receives the tax credit in the year CO_2 is captured and sequestered. Unlike the wind PTC, which guaranteed the taxpayer would receive the PTC for all electricity produced in the 10-year window beginning on the date the project is placed in service, for a new project using the 45Q credit, there was no guarantee that the taxpayer would receive any tax credits in the original program. For example, the taxpayer would not receive any credits, if the project was placed in service after the credit terminated when the 75 million metric ton cap was reached. In addition, if a project was placed in service before the cap was reached, the total value of the tax credits to be earned by the project could not be guaranteed. The project would only have been able to claim the credit for the number of years from the time it was placed in service until the credit expired when the 75 million metric ton cap was reached. This uncertainty as to whether a project would receive any tax credits prevented the credit from being considered in project financing and having the incentive effect necessary to encourage the installation of carbon capture equipment on new or existing coal-fired power plants.

§ 6.03. Summary of Amended § 45Q Tax Credit.

Section 45Q was amended by the Furthering carbon capture, Utilization, Technology, Underground storage, and Reduced Emissions (FUTURE) Act which was included in the Bipartisan Budget Act of 2018[5] enacted on February 9, 2018. The FUTURE Act removes the cap and expands the value of the tax credit to make it an effective incentive to promote investment in CCS projects. Rather than impose a cap, eligibility to claim the credit through the FUTURE Act is limited to a date through which a project must commence construction, providing the needed certainty for project financing. The three most important changes to the credit that greatly improve the accessibility of the tax credit are (1) the large increase in the dollar value of the tax credit and the 12-year credit claiming period for CCS projects; (2) the elimination of the 75 million metric ton cap on tons of CO_2 that could qualify for the credit; and (3) the expansion of the incentive from capturing and sequestering CO_2 to capturing and sequestering all carbon oxides (carbon oxide). The FUTURE Act also added eligibility for claiming the credit from CO_2 that is captured through direct air capture, and a new tax credit for CO_2 conversion.

[1] — Increase in Tax Credit Rates.[6]

In calendar year 2026, the amended credit rates are 50 dollars per ton of carbon oxides sequestered in secure geological storage without having been used in an EOR project (saline storage) and 35 dollars per ton of carbon oxides used in an EOR project and sequestered in secure geologic storage or used in a utilization project. The credit rates for carbon oxides captured and sequestered during the calendar year phase-up from the current rates over a 10-year period as follows:

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5 P.L. 115-123.

6 26 U.S.C.A. § 45Q(a) (2020).

Calendar Year	CO_2 for EOR/Utilization $/Ton	CO_2 for Non-EOR Sequestration $/Ton
2018	15.29	25.70
2019	17.76	28.74
2020	20.22	31.77
2021	22.68	34.81
2022	25.15	37.85
2023	27.15	40.89
2024	30.07	43.92
2025	32.54	46.96
2026	35.00	50.00

Beginning in 2027, the 35 dollar and 50 dollar credit rates will be increased for inflation.

[2] — Removal of 75 Million Metric Ton Cap.[7]

For carbon capture projects placed in service on or after February 9, 2018, the new law eliminates the 75 million metric ton cap on captured CO_2 that qualifies for the credit and provides the new credits rates for every ton of captured and sequestered carbon oxides captured during the 12-year period beginning on the date the capture equipment is placed in service. Under the old law, the 75 million metric ton cap provided no guarantee that a carbon capture project would receive any tax credits. Under the new law, a carbon capture project that commences construction before January 1, 2024, is guaranteed to receive the tax credit for every ton of carbon oxides captured during the 12-year period beginning on the date the project is placed into service (begins capturing CO_2) and the value of those credits can be

7 26 U.S.C.A. § 45Q(g) (2020).

factored into the projects financial pro-forma. (See the effective dates and issues section below for additional information on commence construction.)

[3] — Expansion to Include All Carbon Oxides.[8]

The credit was expanded from CO_2 to include all carbon oxides. One of the reasons for this change was to allow steel plants that emit carbon monoxide to qualify for the credit without have to burn the carbon monoxide and capture the resulting CO_2.

[4] — Change to Definition of Taxpayer Receiving the Tax Credit.[9]

The original credit went to the owner of the qualified facility (the power plant or industrial facility). The new credit goes to the owner of the capture equipment that is installed at or near (in those cases where the CO_2 is merely provided "over the fence") a qualified facility. In addition, the taxpayer may transfer the new credit to the entity that disposes of the qualified carbon oxides, uses it for EOR, or utilizes it. These changes provide flexibility to enable additional financing structures and to attract tax equity investments in carbon capture projects (discussed in more detail below under "authorization to transfer credit").

[5] — Changes to Definition of Qualified Facilities.[10]

A qualified facility is defined as an industrial facility at which carbon capture equipment is placed in service on or after February 9, 2018, on which construction begins before January 1, 2024; and that captures at least:

1. 500,000 metric tons of carbon oxides for an electric generating unit (unchanged from original program);
2. 100,000 metric tons of carbon oxides for other industrial facilities (reduced from 500,000 tons); or

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8 26 U.S.C.A. § 45Q(a) (2020); 26 U.S.C.A. § 45Q(c) (2020).
9 26 U.S.C.A. § 45Q(f)(3)(A) (2020).
10 26 U.S.C.A. § 45Q(d) (2020).

3. 25,000 metric tons of carbon oxides for pilot projects at an industrial facility which emits not more than 500,000 metric tons of carbon oxides and in which the carbon oxides are sequestered in a utilization project.

The January 1, 2024 commence construction date was imposed by Congressional lawmakers in order to limit the cost of the program to the federal government. It is widely recognized that this date may limit the number of projects that could be eligible for the program, and efforts to extend this date are likely to be undertaken.

[6] — Authorization to Transfer Credit.[11]

The new 45Q allows the taxpayer to transfer the credit to the person that disposes of the qualified carbon oxide, utilizes the qualified carbon oxide, or uses the qualified carbon oxide as a tertiary injectant. This change was made to allow the owner of the carbon capture equipment a new option for monetizing the tax credit, particularly in the case where a power plant is owned by an electric cooperative or public power entity. If the owner does not have enough tax liability to be able to utilize all of the tax credits, the owner can sell or transfer the tax credit to the party that purchases the carbon oxide to dispose of it, utilize it, or use it as a tertiary injectant. Additional information is provided in the section on structuring projects.

[7] — Effective Dates and Issues.[12]

The new qualification requirements and tax credit rates apply to carbon oxides captured by equipment placed in service at an industrial facility on or after the date of enactment of the FUTURE Act, February 9, 2018. In order to qualify for the tax credit, construction of the industrial facility must begin before January 1, 2024. Construction on the carbon capture equipment must begin before January 1, 2024, unless the carbon capture equipment was included in the original plans for the industrial facility. On March 9, 2020, the Internal Revenue Service (IRS) and Treasury Department issued

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11 26 U.S.C.A. § 45Q(f)(3)(B) (2020).

12 26 U.S.C.A. § 45Q(a)(2); § 45Q(a)(3); 26 U.S.C.A. § 45Q(d) (2020).

guidance to define what the taxpayer has to do in order to determine the date on which construction begins.

[8] — Definition of Secure Geologic Storage.[13]

Both the original and amended statutes require the carbon oxides injected for permanent sequestration with or with enhanced oil recovery to be permanently sequestered in secure geologic storage. The statute requires the IRS/Treasury to issue regulations in consultation with the Environmental Protection Agency (EPA), the Department of Energy (DOE), and the Department of Interior (DOI), to define what constitutes "secure geological storage." When 45Q was first enacted, the IRS issued Notice 2009-83[14] to provide guidance to taxpayers on what a project needs to undertake in order to meet the definition of secure geologic storage for CO_2 and qualify for the credit. That guidance requires EOR producers to report their CO_2 injections under Subpart RR of the EPA's Greenhouse Gas (GHG) reporting program. This is a program established under the Clean Air Act (CAA) which was drafted and designed for long-term storage of CO_2 under pressure in deep, saline geologic formations. There is a robust discussion taking place among industry stakeholders about these reporting programs, as some EOR operators have indicated they will not enter into long-term offtake agreements for CO_2 that must be reported to EPA under the subpart RR program. In addition, the new credit applies to other carbon oxides for which the EPA has not provided a definition of secure geologic storage.

[9] — Recapture of Tax Credits.[15]

The statute requires the Secretary of the Treasury to issue regulations providing for recapturing the benefits of the tax credit when the qualified carbon oxides for which the credit was taken cease to be sequestered in secure geologic storage.

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13 26 U.S.C.A. § 45Q(f)(2) (2020).

14 I.R.S. Notice 2009-83, 2009-44 I.R.B. 588.

15 26 U.S.C.A. § 45Q(f)(4) (2020).

§ 6.04. IRS/Treasury Non-Regulatory Guidance.

[1] — Applicable Dollar Amounts.

On December 17, 2018, the IRS published Notice 2018-93,[16] the first notice issued under the new § 45Q statute, to address a very narrow issue, the applicable dollar amounts for determining the amount of the 45Q credit for carbon oxides captured under the new rules in calendar years 2018 through 2026.

[2] — Beginning of Construction.

On March 9, 2020, the Internal Revenue Service (IRS) released Notice 2020-12[17] to provide guidance on determining beginning of construction for a project. The Notice follows the previous guidance that has been released by the IRS for renewable energy projects. A project that meets the physical work test or the five-percent safe harbor is deemed to have begun construction on the date the taxpayer first satisfies one of the two methods. Both methods include a continuity of work requirement and the Notice provides a safe harbor of six years for that requirement rather than the four-year period for renewable energy project.

1. Physical Work Test — This test is a facts and circumstances determination that work (both on-site and off-site) performed by the taxpayer and work performed by other persons for the taxpayer under a written binding contract are of a significant nature. The Notice provides several examples of off-site physical work that is of a significant nature.
2. Five Percent Safe Harbor — The Notice includes a spending safe harbor that is based on paying or incurring five percent or more of the total cost of the qualified facility, if the project is for the development of a new industrial facility with carbon capture equipment, or the carbon capture equipment, if the project is to install the equipment on an existing industrial facility.

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16 I.R.S. Notice 2018-93, 2018-51 I.R.B. 1041.

17 I.R.S. Notice 2020-12, 2020-11 I.R.B. 495.

3. Continuity Requirement — The Notice follows the guidance provided for renewable energy projects by requiring a project to meet a "continuity requirement." Under the physical work test, the taxpayer must meet a continuous construction test that involves a fact and circumstances test for whether a continuous program of physical work of a significant nature has occurred from the date on which construction is determined to have begun through the placed-in-service date. Under the five percent safe harbor, the taxpayer must meet a continuous efforts test which requires a fact and circumstances determination of whether a taxpayer has made continuous efforts towards completion of the project. The Notice includes a "Continuity Safe Harbor" that provides for a project to be deemed to meet the Continuity Requirement if the project is placed in service by the end of calendar year that is six years after the year in which the project is determined to have begun construction.
4. Scope of Carbon Capture Project — The Notice provides rules for treating multiple qualified facilities or carbon capture units as part of a single project for the application of the "beginning of construction" rules. Under this guidance, a taxpayer with a single project that includes five carbon capture units will meet the begin construction requirement for all five units by beginning construction on one unit of carbon capture equipment under the physical work test. In theory, the capture units could be on separate qualified (industrial) facilities so long as the Taxpayer can show that all of the capture units are part of a single project using the guidance on the single project determination.
5. Effective Date — The provisions of the Notice are effective on March 9, 2020. A taxpayer whose project met one or both of the begin construction tests before that date, may use March 9, 2020 as the date on which construction began for their project. If the taxpayer's project met both tests, the taxpayer must choose one of the tests (but not both) for purposes of applying the rules included in the Notice.

[3] — Partnership Allocation Safe Harbor.

On March 9, 2020, the IRS released Revenue Procedure 2020-12[18] to establish a safe harbor for the allocation of section 45Q credits to partners in a partnership for purposes of section 704(b) of the Code and the regulations thereunder. This type of safe harbor is necessary to provide project developers and investors with the assurance needed to encourage tax equity to invest in carbon capture projects.

§ 6.05. Proposed Treasury Regulations.

On Friday, January 15, 2021, Treasury and the IRS released and published in the Federal Register the long-anticipated final regulations[19] for the Section 45Q credit for carbon capture and sequestration. The final regulations provide guidance on the issues that interested parties identified as priorities in comments submitted in response to IRS Notice 2019-32 and in the proposed regulations published in the Federal Register on June 2, 2020.[20]

[1] — Secure Geological Storage (§ 1.45Q-3).[21]

In response to recommendations that Treasury and the IRS permit taxpayers to use alternative approaches to the Environmental Protection Agency's rules for demonstrating secure geological storage (40 CFR Part 98 Subpart RR[22]), the proposed regulations permit taxpayers to use the standard adopted by the International Organization for Standardization and endorsed by the American National Standards Institute (CSA/ANSI ISO 27916:19).

That standard, which was developed for quantifying and documenting the total carbon dioxide that is stored in association with enhanced oil recovery,

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18 Rev. Proc. 2020-12, 2020-11 I.R.B. 511.

19 Treas. Reg. §§ 1.45Q-1, -2, -3, -4, -5 (2021); Credit for Carbon Oxide Sequestration, 86 Fed. Reg. 4728, 4730 (January 15, 2021).

20 Prop. Treas. Reg. §§ 1.45Q-1, -2, -3, -4, -5, 865 Fed. Reg. 34050 (June 2, 2020).

21 Treas. Reg. § 1.45Q-3 (2021); Credit for Carbon Oxide Sequestration, 86 Fed. Reg. 4728, 4769 (January 15, 2021).

22 Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, 75 Fed. Reg. 75060, 75078 (December 1, 2010).

"is a viable quantification methodology that is appropriate for these purposes," the government said in the preamble to the regulations.

Treasury declined requests to permit taxpayers to use state reporting rules as an alternative to the EPA and ISO standards. "Reporting rules among states are not uniform and states may have different reporting requirements and different governing bodies to whom carbon dioxide injection projects are required to report," it said. "Adopting such rules would not promote uniformity and would increase the administrative burden on the IRS significantly."

[2] — Recapture (§ 1.45Q-5).[23]

The proposed regulations provide for at most a 15-year recapture period that begins on the date of first injection for secure geological storage or enhance oil recovery and ends on the earlier of three years after the last year in which the taxpayer claims a 45Q credit or the date monitoring ends under the secure geological storage definition.

The proposed rules provide that any recapture amount will be accounted for in the tax year it is identified and reported. If a taxpayer, operator, or regulatory agency determines during the recapture period that qualified carbon oxide has leaked to the atmosphere, the taxpayer will have a recapture amount if the leaked amount of qualified carbon oxide exceeds the amount of qualified carbon oxide disposed of in secure geological storage or used as a tertiary injectant in that tax year.

To simplify the calculation of the recapture amount, the regulations limit recapture to the qualified carbon oxide injected in the three years preceding the year in which the leak is identified and reported. The excess amount of leaked qualified carbon oxide will be recaptured at a credit rate calculated on a last-in, first-out basis. The taxpayer must add the amount of the recaptured section 45Q tax credit to the amount of tax due in the tax year in which the recapture event occurs.

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23 Prop. Treas. Reg. § 1.45Q-5, 86 Fed. Reg. 4770 (January 15, 2021).

The regulations provide a limited recapture exception if carbon leakage results from actions unrelated to the selection, operation, or maintenance of the storage facility, such as volcanic activity or a terrorist attack. The rules also state that if qualified carbon oxide is deliberately removed from a secure storage site, a recapture event occurs in the year in which it is removed from its original storage.

[3] — Contract Requirements (§ 1.45Q-1(h)(2)).[24]

The proposed regulations provide a framework for the types of contracts, terms, and reporting requirements that taxpayers can use to demonstrate the contractual assurance of the capture and disposal, injection, or use of qualified carbon oxide.

The rules permit taxpayers to enter into multiple contracts with multiple parties. The government notes in the preamble that the taxpayer that captures qualified carbon oxide may contract with one party to dispose of a portion of its captured qualified carbon oxide in a deep saline formation, with another party to use another portion of its captured qualified carbon oxide as a tertiary injectant in multiple enhanced oil recovery sites, and with several parties to use the remaining portion of its captured qualified carbon oxide.

The existence of each contract and the parties involved must be annually reported to the IRS on Form 8933, "Carbon Oxide Sequestration Credit." The proposed regulations require taxpayers to contractually ensure the disposal, injection, or use of qualified carbon oxide in a binding written contract that includes commercially reasonable terms that provide for enforcement.

Contracts can specify how much carbon oxide the parties agree to dispose of, inject, or use, and can also include specific provisions relating to enforcement, such as long-term liability provisions, indemnity provisions, or penalties for breach of contract or liquidated damages.

The preamble notes that while the proposed regulations require contracts to include a mechanism for enforcement, no specific enforcement-related provision is required. "This is consistent with allowing contracting

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24 Prop. Treas. Reg. § 1.45Q-1, 86 Fed. Reg. 4763 (January 15, 2021).

parties to tailor their agreements to a wide variety of business needs and circumstances," the government explained.

[4] — Credit Transfer (§ 1.45Q-1(h)(3)).[25]

For taxpayers that own the carbon capture equipment and want to make a section 45Q(f)(3)(B) election to transfer the credit to the party that sequesters or uses the captured carbon oxide, the proposed regulations explain who may make the election and describe the time and manner for doing so.

The proposed regulations provide that elections may be made for all or a portion of the available section 45Q credit and may be made for a single or multiple credit claimants. If an electing taxpayer elects to allow multiple credit claimants, the maximum amount each may claim must be proportional to the amount of qualified carbon oxide disposed of, utilized, or used as a tertiary injectant by the credit claimant.

§ 6.06. Overview of Potential Project Structures.

This is a brief discussion of some of the potential structures that could be used to finance carbon capture. Other project structures and innovative approaches to financing carbon capture projects that have not been identified in this paper may also be available.

[1] — Owner of the Industrial Facility Owns the Carbon Capture Requirement.

In this structure, the owner of the industrial facility would need to have either the adequate income tax liability to utilize the credits or contract with a company that has adequate tax liability and takes the carbon oxide to dispose of it in secure geologic storage, use it in an EOR project with secure geologic storage, or utilize it.

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25 Prop. Treas. Reg. § 1.45Q-1, 86 Fed. Reg. 4764 (January 15, 2021).

[2] — An Entity Not Related to the Owner of the Industrial Facility Owns the Carbon Capture Equipment.

In this structure, an unrelated company would own the carbon capture equipment and contract with the owner of the industrial facility to gain access to the flue gas from which the carbon oxide is captured. The unrelated company could also contract with the industrial facility owner to operate the capture equipment as part of its industrial facility. The unrelated company would need to have either adequate tax liability to use the 45Q credits or contract with a company that has adequate tax liability and takes the carbon oxide to dispose of it in secure geologic storage, use it in an EOR project with secure geologic storage, or utilize it.

[3] — Tax Equity Partnership with the Owner of the Industrial Facility.

In this structure, the owner of the industrial facility would typically lead the construction and operation of the carbon capture equipment that is attached to the industrial facility. The owner of that equipment would be a partnership that includes the owner of the facility and tax equity investors who have the tax liability to use the 45Q tax credits generated by the project. In the typical form of this structure, the tax equity investors would provide capital to build the project and would receive virtually all of the tax credits. During the 12-year credit window the owner of the underlying facility would typically own 1 percent of the partnership and the tax equity investors would own 99 percent of the partnership. At the end of the credit window, the ownership of the partnership flips such that owner of the underlying facility would own upwards of 95 percent of the partnership and the tax investors would own 5 percent of the partnership.

[4] — Sale/Leaseback Transactions.

In this structure, the owner of the industrial facility would build the carbon capture project, sell it to third-party investors with sufficient tax liability, and then lease the equipment from the investors. The investors would be compensated with the lease payments and the 45Q tax credits. The end of this structure is not as clear, since the lessee would have to buy out the investors at some point after the credit window ends.

§ 6.07. Overview of Non-Tax Barriers to Carbon Capture Projects.

[1] — Cost of New Technology

The 45Q tax credit, even when fully phased-in, and the sales proceeds from the carbon oxide may not be enough to cover the cost of building and operating the carbon capture equipment installed on an electric generating unit. This would depend on a number of factors, including the cost of the capture equipment, cost of CO_2 that could be contracted for EOR use which is in many cases dependent on the price of oil and/or location of the EOR project, and other project factors.

[2] — Other Issues.

Issues such as liability from potential releases of sequestered carbon oxide into the atmosphere need to be resolved to ensure the financial certainty of the tax credit to a project.

Chapter 7

Property Law and Oil & Gas Issues Raised by Carbon Capture and Storage

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§ 7.01. Introduction.

A great deal of attention is being given to a process called carbon capture and storage, or interchangeably, sometimes called carbon capture and sequestration. This process involves two main steps. The first step requires the "capture" of carbon dioxide from some source. Most commonly this capture likely would mean the removal of carbon dioxide from a gaseous stream, with the remainder of the stream being emitted to the atmosphere from an industrial source, but it could mean the separation and removal of carbon dioxide directly from the atmosphere.

The second step would involve the injection of carbon dioxide into the subsurface. This injection could be done for purposes of permanent disposal (a/k/a as storage or sequestration) of the carbon dioxide, in order to prevent it from being emitted into the atmosphere. The motivation to do this would be to help slow the pace of climate change (or, in the views of some very optimistic persons, to even to halt or reverse climate change).

Alternatively, the carbon dioxide could be injected into the surface as part of an enhanced oil recovery project (EOR), as is currently done in many locations. Some of the carbon dioxide that is injected in EOR is produced in conjunction with the oil recovered in the EOR operation. That carbon dioxide is separated from the oil and recycled into the stream of carbon dioxide being injected. But a portion of the carbon dioxide remains in the subsurface formation in which EOR is being conducted. Thus, to the extent that an EOR operation might inject carbon dioxide that was either captured from the atmosphere or captured from an industrial stream before it was emitted into the atmosphere, the injection of carbon dioxide during EOR can reduce the amount of carbon dioxide that would otherwise be in the atmosphere, in much the same way as when carbon dioxide is injected for the purpose of permanent disposal.

The prospect for carbon capture and storage operations will raise various property law issues. Further, it can raise various issues relating to mineral rights and production. This chapter will discuss the property law issues. It also will discuss issues relating to mineral rights and mineral production issues, with particular attention to oil and gas, though some of the same issues that relate to oil and gas can arise with respect to other types of mineral exploration and production.

§ 7.02. Basic Property Law Issues.

[1] — Who Has the Right to Conduct or Authorize Carbon Sequestration: Whether the Subsurface Is Susceptible of Private Ownership, and If So, Who Generally Owns the Subsurface?

In the United States, state law generally governs property rights and issues relating to the nature and extent of a landowner's ownership.[1] Accordingly, state law will govern any questions regarding the ownership of the subsurface, including subsurface pore spaces. Of course, with respect to many property law issues, various states each reach develop rules that are similar or identical the rules developed by other states.

Prominent common law commentators and numerous American courts have expressed a maxim known as the "*ad ceolum*" doctrine, which provides that the owner of land owns not just the surface, but the entire airspace above the land and the entire subsurface below it.[2] This doctrine's name comes from the Latin phrase "*cujus est solum ejus est usque ad coelum et ad inferos*," which has been translated as "for whoever owns the soil, it is theirs up to Heaven and down to Hell."[3]

On numerous occasions, courts have held that liability for trespass can be based on airspace or subsurface intrusions. For example, courts have held that a landowner has an action in trespass when some portion of a neighboring building or other construction intrudes into his airspace. Such intrusions have included eaves,[4] cornices,[5] and roofs[6] that project over a plaintiff's property. Courts have held that wires passing over a plaintiff's property can constitute

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1 Stop the Beach Renourishment, Inc. v. Florida Dept. of Environmental Protection, 130 S. Ct. 2592, 2597 (2010) ("Generally speaking, state law defines property interests. …"); Phillips v. Washington Legal Foundation, 118 S. Ct. 1925, 1930 (1998).

2 Thrasher v. City of Atlanta, 173 S.E. 817, 825 (Ga. 1934).

3 Alyce Gaines Johnson Special Trust v. El Paso E & P Co., L.P., 773 F.Supp.2d 640, 645 (W.D. La. 2011).

4 Huber v. Stark, 102 N.W. 12 (Wis. 1905), *cf.* Aiken v. Benedict, 39 Barb.(N.Y.) 400 (N.Y. 1863) (ejectment action).

5 Harrington v. McCarthy, 48 N.E. 278 (Mass. 1897).

6 Murphy v. Bolger, 15 A. 365 (Vt. 1888).

a trespass,[7] and one court held that a defendant committed a trespass when she extended her arm over the property line.[8] Courts also have recognized that a person commits a trespass when he drills a well that bottoms below the plaintiff's land.[9]

Notably, these airspace intrusions all occurred relatively near the surface, elevations that the plaintiff was actually using, at elevations close to those the plaintiff was using, or at elevations that the plaintiff reasonably could be expected to use. What about intrusions at greater elevations or far beneath the surface? This raises the question of whether a landowner's ownership really does extend all the way to the center of the earth and all the way to the heavens (with "heavens" presumably meaning outer space).

[2] — Possible Limitations on the Depth to Which the Landowner's Ownership or Rights Extend.

There are at least two potential bases on which courts might limit the extent of a landowner's subsurface rights — public policy and the potential viewpoint that a landowner's interest in using, possessing, and excluding others from the "land" become attenuated at great distances from the surface. These two bases have come into play in jurisprudence that has limited a landowner's rights to exclude others from airspace above land, and these bases have sometimes come into play in jurisprudence limiting the landowner's right to exclude others in the subsurface context.

Below, this section of the chapter first discussions limitations on the landowner's rights in the airspace. These are discussed because limitations on such rights are widely accepted and because the justifications for limitations on a landowner's rights in the airspace above the land are arguably analogous to rationales that might justify restrictions on a landowner's rights in the

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7 Marcus Cable Associates, L.P. v. Krohn, 90 S.W.3d 697 (Tex. 2002); Butler v. Frontier Telephone Co., 79 N.E. 716 (N.Y. 1906).

8 Hannabalson v. Sessions, 90 N.W. 93 (Iowa 1902).

9 Wiliams v. Continental Oil Co., 14 F.R.D. 58 (W.D. Okla. 1953); Hastings Oil Co. v. Texas Co., 234 S.W.2d 389 (Tex. 1950); Gliptis v. Fifteen Oil Co., 16 So. 2d 471 (La. 1944); Alphonzo E. Bell Corporation v. Bell View Oil Syndicate, 76 P.2d 167 (Cal. App. 1938).

subsurface. Following that discussion, this section of the chapter discusses limitations that have been recognized in the landowner's subsurface rights.

[a] — Limitations on Landowner's Right to Exclude Others from Airspace Above the Land.

It is well-established that a landowner has no cause of action in trespass against persons who engage in high-altitude air travel over his property. In *Thrasher v. City of Atlanta*, the plaintiff brought a claim for trespass, based on aircraft flying over his land.[10] At that time, Georgia's Civil Code declared that "the right of the owner of lands extends downward and upward indefinitely."[11] Further, the Code stated that "the owner of realty having title downwards and upwards indefinitely, an unlawful interference with his rights, below or above the surface, alike gives him a right of action."[12] The Georgia Supreme Court noted the importance of air travel to society,[13] but ultimately based its decision on a property rights analysis.

The court concluded that the relevant provisions of Georgia's Civil Code were based on the common law's *ad coelum* doctrine and therefore should be interpreted as including any limitations existing within that doctrine.[14] The court analyzed the doctrine and concluded that the full, literal expression of the doctrine is mere dicta. The court explained that, "The common-law cases from which the *ad coelum* doctrine emanated were limited to facts and conditions close to earth and did not require an adjudication on the title to the mansions in the sky."[15] Therefore, the pronouncements from such cases was mere dicta with respect to higher altitudes.[16]

The Georgia Supreme Court stated that all "[p]ossession is the basis of all ownership" and that title to land therefore "can hardly extend above

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10 Thrasher v. City of Atlanta, 173 S.E. 817, 825 (Ga. 1934).

11 *Id*. (citing Ga. Civ. Code (1910) § 3617).

12 *Id*. (citing Ga. Civ. Code (1910) § 4477).

13 *Id*. at 819.

14 *Id*. at 825 ("These provisions of the Code should therefore be construed in the light of the authoritative content of the maxim itself.").

15 *Id*.

16 *Id*.

an altitude representing the reasonable possibility of man's occupation and domain."[17] The court reasoned that a landowner could claim possession to the height of any building, and perhaps the landowner could be deemed to hold actual possession of the space immediately above the "trees, buildings, and structures affixed to the soil."[18] Further, if a neighbor constructed a tall building with an overhang projecting over the landowner's property, that construction would demonstrate that the space was subject to actual possession and therefore the overhang might be the basis for a trespass action.[19]

But flying through the airspace at high altitude is not an act of possession.[20] Therefore, air travel at low altitude across a person's property might constitute a trespass,[21] and the operation of aircraft at higher altitudes that actually interferes with a landowner's use of the land might constitute a nuisance,[22] but air travel at higher altitudes would not constitute a trespass.[23]

In other cases in which landowners have complained about aircraft flying over their property, courts similarly have concluded that the *ad coelum* doctrine is dicta to the extent that it suggests title to land extends to indefinite altitudes and that landowners may be entitled to relief for flights at low altitude or for air travel that causes actual harm or inconvenience, but that

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17 *Id*. at 825.

18 *Id*. at 826.

19 *Id*. at 825.

20 *Id*. at 825-6.

21 *Id*. at 826.

22 *Id*. at 825 (landowner "may complain of any [flights] tending to diminish the free enjoyment of the soil," though the air travel might be at altitudes above the altitude subject to possession); *id*. at 826 ("it could be a nuisance" if the air travel causes harm or inconvenience").

23 The decision is based on a conclusion that ownership does not extend indefinitely upward. If a court concluded that ownership extended indefinitely upward, but that constructive possession did not, such reasoning might also bar a trespass claim, given that a landowner would not have actual possession of high elevations and that a person must have actual or constructive possession in order to bring a trespass claim. But if ownership extended indefinitely upward, a landowner might be able to bring a claim based on some other theory, such as ejectment.

landowners are not entitled to bar high altitude fly overs.[24] A particularly notable decision is the 1946 United States Supreme Court opinion in *United States v. Causby*.[25]

In *Causby*, a plaintiff who lived near an airfield brought suit, asserting that low level flights had effected a "taking" of his property and that he was entitled to compensation. The Court ruled that, under the facts shown, the plaintiff could assert a takings claim because the flights seriously impaired the plaintiff's use and enjoyment of his property,[26] which extends upward from the surface to encompass "at least as much of the space above the ground as he can occupy or use in connection with the land."[27] But the Court also suggested a landowner would not have grounds to complain about the mere fact that aircraft fly over his property at high altitudes. The Court explained that the "[*ad coelum*] doctrine has no place in the modern world," and the "public interest" requires that the air be a "public highway."[28]

The Restatement (Second) of Torts reaches a similar result. Section 159 establishes a general rule that trespasses may occur "above the surface of the

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24 Smith v. New England Aircraft Co., 170 N.E. 385, 393 (Mass. 1930) (noting altitude of "possible effective possession" as potential limit on trespass claims); Swetland v. Curtiss Airports Corp., 41 F.2d 929, 938 (N.D. Ohio) (noting that decisions suggesting title to land extended to indefinite heights did not involve disputes over alleged trespasses at altitudes generally used in air travel); Rochester Gas & Elec. Corp., 266 N.Y.S. 469, 471 (N.Y. Ct. App. 1933) ("it may be confidently stated that, if [the *ad coelum*] maxim ever meant that the owner of land owned the space above the land to an indefinite height, it is no longer the law").

25 United States v. Causby, 328 U.S. 256, 66 S. Ct. 1062 (1946).

26 United States v. Causby, 328 U.S. at 266-7, 66 S. Ct. at 1068.

27 *Id*. at 1067.

28 *Id*. at 1065. *See also* United States v. Causby, 328 U.S. at 266, 66 S. Ct. at 1068 ("The airspace, apart from the immediate reaches above the land, is part of the public domain."). The Ohio Supreme Court applied the reasoning that the *ad coelum* doctrine does not apply in its full literal expression in support of its holding that a plaintiff did not have a takings claim based on a zoning law that limited heights of buildings near an airport. Village of Willoughby Hills v. Corrigan, 278 N.E.2d 658, 664 (Ohio 1972) ("It is now well settled that the doctrine of the common law, that the ownership of land extends to the periphery of the universe, has no place in the modern world."). Such reasoning goes further than the decisions that hold that a landowner's ownership does not extend beyond the height he can reasonably possess, but is consistent with the proposition that the *ad coelum* doctrine is not applied literally.

earth," but the Section also states that an aircraft's flight over land will not constitute a trespass unless the aircraft "enters into the immediate reaches of the air space next to the land, and … it substantially interferes with the other's use and enjoyment of his land."[29] Some of the court's language suggested that it was resting its holding on a public policy rationale, though the court's suggestion that ownership might extend only so far as a person could actually use and enjoy the property has overtones of basic property law.

[b] — Limitations on the Landowner's Right to Exclude Others from the Subsurface.

To the extent that there might be limitations on a landowner's rights in the subsurface, it might be possible for someone to engage in carbon dioxide storage operations without obtaining rights from the landowner. This probably is not advisable, because, as is noted earlier in this chapter, it seems that a landowner has rights in the subsurface, and that these rights may be sufficient to preclude a person's use of the subsurface for carbon sequestration without first obtaining rights from the landowner. Nevertheless, the possibility of limitations on the landowner's rights is discussed in this section. And, in several contexts, courts have concluded that there are limitations on a landowner's subsurface rights. These contexts are different than the carbon sequestration context, but they arguably have some persuasive value as to potential limitations on a landowner's rights in the context of carbon sequestration.

[i] — Injection Disposal Cases.

Many liquid wastes are discarded in injection disposal wells.[30] The process is the opposite of what happens in the production of oil from an oil

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[29] The Restatement (First) Torts is similar. Section 159 states that a trespass can occur "above the surface of the earth," but Section 194 provides that air travel over land will not constitute a trespass if the travel complies with applicable regulation and it has a legitimate purpose, is conducted in a reasonable manner, and occurs "at such a height as not to interfere unreasonably with the possessor's enjoyment of the surface of the earth and the air space above it."

[30] *See* General Information About Injection Wells, EPA, http://water.epa.gov/type/groundwater/uic/basicinformation.cfm#what_is. Section C of the Safe Drinking Water Act governs underground injections. 42 U.S.C. § 300h(a)-(b). More than 650,000 injection wells

well or water from a water well. The liquid waste is pumped down a well that has been drilled to a permeable formation. The waste exits the well and migrates into the formation. Over time, as more and more waste liquid is injected into the disposal well, the waste fluid can migrate across subsurface property lines.

In a handful of cases, plaintiffs have filed lawsuits, alleging that a neighbor's operation of an injection disposal well has resulted in a subsurface trespass of waste fluids. The trend in such suits is for courts to hold that a plaintiff cannot maintain a subsurface trespass action merely based on the migration of waste fluids into the subsurface of his property. Instead, a plaintiff must be able to show actual damages or an interference with some reasonably anticipated use of his property in order to sustain a trespass action.[31]

For example, in *Chance v. BP Chemicals, Inc*., the plaintiffs brought a class action, asserting trespass claims that were based on allegations that fluids from the defendant's injection disposal well had intruded into the subsurface of the plaintiffs' properties.[32] After a jury returned a verdict finding that the plaintiffs had not proven actual damages or an unreasonable interference with a foreseeable use of their properties, the trial court entered judgment for the defendant.[33] The appellate court affirmed and the Ohio Supreme Court agreed to review the case.

The plaintiffs argued that proof of a subsurface intrusion is sufficient to prove a trespass and that once a trespass is proven damages could be presumed.[34] The Ohio Supreme Court disagreed. The court declared that the *ad coelum* doctrine has no place in the modern world."[35] The court then quoted with approval a case in which the Ninth Circuit stated that a person's

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have been granted permits to operate under the Safe Drinking Water Act. *See* UIC Injection Well Inventory, EPA, https://www.epa.gov/uic/uic-injection-well-inventory.

31 *See, e.g*., West Edmond Salt Water Disposal Assn. v. Rosecrans, 226 P.2d 965 (Okla. 1950).

32 Chance v. BP Chemicals, Inc., 670 N.E.2d 985, 986 (Ohio 1996).

33 *Id*. at 989.

34 *Id*. at 993.

35 *Id*. at 991 (citing Winston v. Cornish, 5 Ohio 477, 478 (1832)).

ownership of the airspace above his land extends only so far as the space he can use and occupy.[36] The Ohio Supreme Court concluded that similar reasoning should be extended to subsurface rights. [37] Therefore, in order for litigants to recover in trespass for the sort of subsurface intrusion alleged by the plaintiffs, they must prove "physical damage or actual interference with the reasonable and foreseeable use of the properties."[38] Because the plaintiffs had not proven damages or interference with use, the Ohio Supreme Court affirmed the judgment against them.[39]

In *Boudreaux v. Jefferson Island Storage & Hub*, the plaintiffs brought suit under Louisiana law, asserting a trespass claim based on the allegation that the salt water from the defendant's injection disposal well had intruded into the subsurface of their property.[40] The United States Court of Appeals for the Fifth Circuit held that the plaintiffs had not established an actionable trespass.[41] The court reasoned that Louisiana law would not allow recovery

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36 *Id.* at 991-2.

37 *Id.* at 992. The court also observed that "ownership rights in today's world are not so clear-cut as they were before the advent of airplanes and injection wells." *Id.*

38 *Id*. at 993.

39 *Id*. at 994. *See also* Baker v. Chevron USA, Inc., 2009 WL 3698419 (S.D. Ohio 2009).

In a Kansas case, the plaintiffs complained about an escape of natural gas from a storage facility. The plaintiffs proceeded on negligence and nuisance claims only, after voluntarily dismissing their trespass claims, so trespass claims were not at issue, but the Kansas Supreme Court referred to the Ohio Supreme Court's rejection of the plaintiff's trespass theory in Chance v. BP and stated that in Kansas the result likely would be the same — a plaintiff could not recover for subsurface trespass without showing damages or unreasonable interference with a foreseeable use of his property. Smith v. Kansas Gas Service Co., 169 P.3d 1052, 1061 (Kan. 2007).

In a dispute over subsurface water flows, the Colorado Supreme Court suggested that it found the reasoning of the Ohio Supreme Court to be persuasive, though the Colorado court's decision appears to have been based in large part on Colorado water law. Board of County Commissioners v. Park County Sportsmen's Ranch, LLP, 45 P.3d 693 (Colo. 2002).

40 Boudreaux v. Jefferson Island Storage & Hub, 255 F.3d 271, 272 (5th Cir 2001).

41 *Id*. at 274. The court seemed to put some weight on the fact that the defendant had received a permit from the Louisiana Department of Conservation to operate the injection disposal well, but that generally should not be a basis for distinguishing the typical cross-border fracturing case because in most or all states the operator of the well will have been required to secure a permit in order to drill the well. Prior to *Boudreaux*, the United States

for subsurface intrusion unless the plaintiff could show actual damages or "measurable inconvenience."[42] Because the plaintiffs had not proven either of those things, they had failed to establish an actionable trespass.[43] The mere existence of a physical intrusion was not sufficient.

A respected torts hornbook espouses a similar view. The hornbook criticizes a 1929 Kentucky decision in which the court, "notwithstanding a forceful dissenting opinion," allowed a surface owner to recover in trespass on the grounds that the defendant had entered the subsurface of plaintiff's land via a case at a depth of 360 feet below the surface.[44] Noting that the plaintiff had no practical access to the case and no prospect for access, the hornbook characterizes the decision as "very bad" and as being "dog-in-the-manger law."[45] The hornbook states that relief should not be allowed in such cases unless there is some damage to the surface or some interference with a plaintiff's use of the property.[46] Turning to subsurface intrusions caused by injection disposal and gas storage, the hornbook notes that "[p]erhaps there should be no liability for subsurface invasions of water, gas, or other substances" unless the plaintiff can prove actual damages, an interference with his use of the property, or, when oil and gas rights are involved, the "unjustifiabl[e] appropriate[ion]" of products.[47]

District Court for the Eastern District of Louisiana rejected claims in two similar cases based on the same reasoning. Mongrue v. Monsanto, 1999 WL 970354 (E.D. La. 1991), *aff'd*, 249 F.3d 422 (5th Cir. 2001); Raymond v. Union Texas Petroleum Corp., 697 F. Supp. 270 (E.D. La. 1988).

42 *Id*. at 275.

43 *Id*.

44 W. Page Keeton, et al., PROSSER AND KEETON ON TORTS at Ch. 3, § 13 (p. 82) (5th ed. 1984).

45 *Id*. The "dog-in-the-manger" references is derived from the Aesop's Fable in which a dog refuses to let an ox eat hay from a feed trough even though the dog itself cannot eat hay.

46 *Id*.

47 *Id*. at 82. In a subsequent section, this chapter explains why, at least in certain circumstances, drainage of oil and gas that is facilitated by cross-boundary fracturing should not be considered an "unjustifiable appropriation."

The Restatement (Second) of Torts recognizes that a trespass can occur below the surface,[48] but this does not necessarily mean that the Restatement would impose liability for intrusions by injections resulting from injection disposal. Liability for trespass is based on entering land "in the possession of the other."[49] The Restatement provides that, to be in possession of land, a person must be in "occupancy" of it.[50] The comments explain that "occupancy" means "such acts done upon the land as manifest a claim of exclusive control of the land," and as an example, the comments note that a person's construction of an enclosure around land generally will qualify as occupancy of the entire area enclosed.[51] In the typical case in which a landowner complains about injection disposal, the defendant likely can make a strong argument that the complaining landowner does not have possession of the land at the depths where the injection disposal is being done.

[ii] — Conservation Laws — Pooling and Unitization.

Conservation laws can modify rules relating to trespass. In *Nunez v. Wainoco Oil & Gas Co.*,[52] the Louisiana Commissioner of Conservation entered orders creating a compulsory unit and issued a permit authorizing Wainoco to drill a well that became the unit well. The drilling began on leased property, near an unleased tract that was part of the unit. After the well was completed, a directional survey indicated that the drilling had deviated from vertical and that the well had bottomed about four or five feet inside the subsurface of the unleased tract. The owner of that tract brought a trespass action against Wainoco and other defendants who owned mineral interests in the unit, seeking an order that required the operator to remove the wellbore.

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48 Restatement (Second) Torts § 158. The Restatement (First) of Torts has a similar provision in Section 159.

49 Restatement (Second) Torts § 158. Similarly, Restatement (First) of Torts § 162 states trespass liability is owned only to persons in possession of land.

50 Restatement (Second) Torts § 157. Restatement (First) of Torts § 157 has a similar definition of "possession."

51 Restatement (Second) Torts § 157 comment (a). Restatement (First) Torts § 157 comment (a) has a similar definition of "occupancy."

52 Nunez v. Wainoco Oil & Gas Co., 488 So. 2d 955 (La. 1986).

The district court dismissed the action, concluding that it was an improper collateral attack on an order of the Commissioner of Conservation. The appellate court reversed, and remanded the case so that the district court could determine whether a trespass occurred. The Louisiana Supreme Court granted review and dismissed the case, but on different grounds than the district court had done so.

The Supreme Court stated that compulsory unitization converts the separate exploration and development rights held by different persons within the drilling unit into a common interest for the drilling and development of the unit.[53] The court described the common interest as "a departure from the traditional notions of private property."[54] The court then explained that this departure is justified as a "reasonable exercise of the police power" because oil and gas "migrate to points of lower pressure caused by … drilling," so that one person's production of oil or gas affects "the correlative rights" of others who have exploration and development rights that apply to the "common reservoir."[55] Indeed, unitization "*protect[s]* private property [by] preventing it by being taken by one of the common owners without regard to the enjoyment of the others."[56]

The court noted that this had "supercede[d] in part" Louisiana's rule that the surface owner also owns the subsurface, and that the trespass alleged by the plaintiff was a subsurface trespass, not a surface trespass. The court then concluded:

"Since established private property law concepts, such as trespass, have been superceded in part by Louisiana's Conservation Law when a unit has been created by order of the Commissioner, we do not find that a legally actionable trespass has occurred in this instance."[57]

In a subsequent dispute between Nunez and Wainoco, the Louisiana Third Circuit applied the same principle in concluding that unitization

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53 *Id*. at 961-2.
54 *Id*.
55 *Id*. at 962-3.
56 *Id*. at 963 (quoting Ohio Oil Co. v. Indiana, 177 U.S. 190 (1900)).
57 *Id*. at 964.

orders and the grant of a drilling permit for a particular location can also alter the rules relating to surface trespass. In that subsequent dispute, Nunez complained about Wainoco used a portion of his land while drilling a well just on the other side of the property line. Using a portion of Nunez's surface during the drilling process had been necessary because, although the well site was not on Nunez's property, the site designated on the drilling permit was near the property line. The appellate court stated that an operator might be required to compensate the non-consenting landowner for any damages to his property, but the mere use of his land is not a basis for trespass liability if use of the land is necessary in order to drill a unit well at the location specified by the Commissioner of Conservation.

Similarly, the Oklahoma Supreme Court has held that the operator of a pooled unit even has the right to drill a unit well at a surface location owned by a landowner who refuses to give his consent,[58] though the owner might be entitled to compensation for the value of such use under the Takings Clause of the Oklahoma Constitution.[59] Further, the North Dakota Supreme Court has held that, when the state's regulators have created a compulsory unit, an operator does not incur liability for trespass by drilling a horizontal well beneath the property of an unleased owner without that owner's consent.[60]

[iii] — Allocation Wells.

A Pennsylvania statute authorizes a lessee that has leases on adjacent tracts to drill a horizontal wells whose wellbore crosses multiple tracts, even in the absence of pooling, subject to an obligation to allocate the well's production between the tracts in a reasonable fashion. Of course, in the absence of this statute, such a lessee already had authority to drill a well on

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58 Texas Oil and Gas Corp. v. Rein, 534 P.2d 1277 (Okla. 1975).

59 Cormack v. Wil-Mc Corp., 661 P.2d 525, 526-7 (Okla. 1983) (citing Okla. Const. art. 2, sec. 23).

60 Continental Resources, Inc. v. Farrar Oil Co., 559 N.W.2d 841, 846 (N.D. 1997). The cases discussed in this section of the chapter do not figure prominently in the eventual "Model" that this Article suggests is the appropriate synthesis of existing subsurface trespass rules, but these cases support the conclusion that that are numerous exceptions to a literal application of the *ad coelum* doctrine.

and produce oil or gas from each tract. So, what is the practical effect of this statute. First, it effectively eliminates any requirement that the wellbore be any particular minimum distance from property lines.

Second, in such a well, the oil or gas that enters the wellbore via perforations located beneath the tract that is at the end (near the "toe") of the wellbore will have to travel through the portion of the well that lies beneath other tracts. In the absence of pooling, the use of those other tracts to help transport oil or gas from the "toe tract" might exceed the lessee's implied easement for use of those other tracts. Thus, the use of those other tracts to transport the "toe tract" gas might constitute a trespass under traditional rules of trespass. This Pennsylvania statute should effectively eliminate a claim for trespass by the owners of the other tracts for the intrusion associated by use of those owners' tracts to transport gas from the "toe tract." Thus, this statue establishes a restriction on the landowners' claims for subsurface trespass in the limited context.

[iv] — Hydraulic Fracturing (Dicta).

In *Coastal Oil & Gas v. Garza Energy Trust*,[61] the plaintiffs asserted that the defendant committed a subsurface trespass by conducting hydraulic fracturing operations on neighboring property that caused fracturing fluid to intrude into the subsurface of the plaintiffs' land. The Texas Supreme Court observed in dicta that the law of trespass need not be the same a couple of miles beneath the surface as at the surface. The court's implication was that a landowner's rights in deep portions of the subsurface were not as strong as his or her rights at the surface. The court ultimately resolved the trespass claim in favor of the defendant on other grounds, reasoning that: (1) the plaintiffs had a non-possessory interest in the subsurface area at issue because someone else owned the mineral estate; (2) because the plaintiffs held a non-possessory interest, they had to show damages in order to prevail; and (3) the rule of capture precluded the claim for the only damages alleged by the plaintiffs—that hydrocarbons from beneath their land drained to the

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61 Coastal Oil & Gas v. Garza Energy Trust, 268 S.W.3d 1 (Tex. 2008).

defendant's wellbore beneath neighboring land via fractures that had been caused by the defendant's fracturing operation. However, the court's dicta is another example of a court concluding that a landowner's right to exclude others from his or her land becomes attenuated when the portion of the "land" at issue is the airspace or subsurface at a significant distance from the surface.

[v] — Subway Case.

In *Boehringer v. Montalto*, the plaintiff sold property to the defendant on credit, taking a mortgage and giving a warranty that the property was free form encumbrances.[62] The plaintiff later brought an action to foreclose on the mortgage and the defendant counterclaimed, alleging that the plaintiff had breached the warranty because the property was not free from encumbrances.[63] Evidence showed that the Bronx Valley Sewer Commission previously had constructed the sewer beneath the property at a depth of about 150 feet, after acquiring the right to do so by condemnation.[64] The Commission had not acquired any right to access the sewer via the surface of the property that the plaintiff had sold to the defendant.[65]

After briefly taking note of prior disputes regarding ownership of airspace above property, the court stated that, "It therefore appears that the old theory that the title of an owner of real property extends indefinitely upward and downward is no longer an accepted principle of law in its entirety."[66] The court concluded that "the title of an owner of the soil will not be extended to a depth below ground beyond which the owner may not reasonably make sue thereof."[67] The court concluded that the Bronx Valley sewer was located below the deepest depth that the defendant "can conceivably make use of

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62 Boehringer v. Montalto, 254 N.Y.S. 276, 276 (N.Y. Dist. Ct. 1931).

63 *Id*. at 276-7.

64 *Id*. at 277.

65 *Id*.

66 *Id*. at 278.

67 *Id*.

the property."[68] Accordingly, the Bronx Valley sewer and the Commission's easement did not encumber the defendant's property.[69]

[vi] — Natural Gas Storage Case.

In the context of subsurface storage of natural gas some statutes seem to have recognized implicitly recognize that a storage operator may need to acquire rights from the landowner. For example, the federal Natural Gas Act authorizes a company to use eminent domain in certain circumstances to acquire the right to use the subsurface of a landowner's land for the storage of natural gas.[70] Some states have similar statutory provisions.[71] However, a federal appellate court held that, under Ohio law, a natural gas storage operator that failed to acquire subsurface rights from landowners was not liable for trespass.[72] In reaching its decision, the federal appellate court relied on the Ohio Supreme Court's decision in *Chance v. BP Chemicals, Inc*., which is discussed above in the injection disposal context.

[3] — Who Owns the Subsurface When There Is a Split Estate?

If there is a split estate, with one person owning the land and another person owning a severed mineral estate, who owns the subsurface? This is relevant because the person who owns the subsurface is likely the person who could conduct authorize carbon sequestration.

The landowner is often called the "surface owner" in such contexts, and although the mineral estate owner is occasionally (though less commonly) called the subsurface owner, these terms are misnomers. The mineral interest owner does not own the subsurface. The mineral owner instead merely has

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68 *Id*.

69 *Id*.

70 15 U.S.C. § 717f; *see also* Columbia Gas Transmission v. Exclusive Gas Storage Easement, 776 F.2d 125, 128 (6th Cir.1985); Mississippi River Transmission Corp. v. Tabor, 757 F.2d 662, 666 n. 5 (5th Cir.1985); Transcontinental Gas Pipe Line Corp. v. 118 Acres of Land, 745 F. Supp. 366, 368 (E.D.La.1990).

71 La. Rev. Stat. 19:1 *et seq*.; Mid-Louisiana Gas Co. v. Sanchez, 280 So. 2d 406, 410 (La. App. 4th Cir. 1973).

72 Baatz v. Columbia Gas Transmission, LLC, 929 F.3d 767, 770 (6th Cir. 2019).

the right to explore for and produce minerals, along with the right to use both the surface and subsurface as reasonably necessary for such exploration and production.[73]

Further, although landowner or "surface owner" may not have the right to explore for and produce minerals, the surface owner otherwise owns both the surface and the regions above and below it — that is, the airspace and the subsurface. Accordingly, the landowner or "surface owner" generally owns the subsurface. However, the landowner's right to use the surface and subsurface may be tempered by an obligation not to interfere with the mineral owner's right to explore for and produce minerals.

There are several cases that conclude that the landowner generally is the person who owns subsurface rights, even when someone else owns the mineral interests associated with the land. For example, there several cases from Louisiana in which a subsurface storage operator was using federal eminent domain rights acquire subsurface storage rights for tracts that were subject to a mineral servitude (under Louisiana's civil law property system, a mineral servitude is somewhat like a severed mineral interest). The courts were faced with the question of who was entitled to compensation for the taking of subsurface storage rights, the landowner or the mineral servitude owner. The courts held that the landowner was the person entitled to compensation, not the mineral servitude owner.

Also, in *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39 (Tex. 2017), the Texas Supreme Court was faced with the question of who owned certain subsurface rights. In that case, there was a severed mineral estate. The issue in dispute was whether the landowner could authorize Anadarko to drill through the subsurface over the objection of the mineral estate owner. The Texas Supreme Court held that the landowner could authorize such drilling because the landowner generally owns the subsurface.

Further, even to the extent that the mineral estate owner had a possessory interest in the actual oil and gas molecules in a certain formation through

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73 In an ownership in place state, this may also include the ownership of any minerals in the subsurface that the mineral owner had a right to produce, but would not include the entirety of the subsurface.

which Anadarko would drill, so that the drilling through that formation could constitute a trespass, the Court held that the loss of hydrocarbons from the volume of space occupied by Anadarko's wellbore was not sufficient to justify the mineral estate owner's request to block the drilling. Because Anadarko's drilling through the subsurface was necessary to allow production from a neighboring tract where Anadarko held an oil and gas lease, but could not utilize the surface for drilling, and because production from the neighboring tract had social utility, the drilling would be allowed, with the consent of the landowner.

[4] — How Someone Would Acquire the Right to Use the Subsurface for Carbon Sequestration.

As owner of the subsurface, a landowner generally would have a right to conduct carbon sequestration operations beneath his or her own land,[74] though if the land is subject to an oil and gas lease or severed mineral estate, the landowner generally would be under an obligation not to interfere with the mineral owner's oil and gas operations.

How would someone other than the landowner obtain rights to engage in carbon sequestration? Of course, a person could bargain to acquire such rights from the landowner, but it also may be possible for a person to obtain such rights in the absence of an agreement. Some states have passed laws to promote and regulate carbon sequestration, and some of those laws authorize the possibility of a prospective carbon sequestration operator obtain subsurface sequestration rights either through an eminent domain process or through a process that work somewhat like compulsory pooling or unitization for oil and gas.

§ 7.03. Mineral Rights and CCS.

As noted above, even if land is subject to an oil and gas lease or even if there is a severed mineral estate, the landowner generally is the person who would have a right to conduct or authorize carbon sequestration. However, if

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74 This statement is speaking from the perspective of property rights. There also are regulatory requirements that would have to be satisfied under the federal Safe Drinking Water Act's underground injection control regulations and perhaps under state law.

someone other than the landowner holds the right to explore for and produce minerals, various other issues can arise.

[1] — The Dominant Estate: the Landowner's Obligation Not to Interfere with the Mineral Owner's Mineral Operations.

Generally, if the land is subject to an oil and gas lease or a severed mineral interest, a landowner will have a duty not to interfere with oil and gas exploration and production. Thus, if the land is subject to an oil and gas lease or a mineral severance, the landowner likely would not have a right to conduct or authorize any carbon sequestration operations that would unreasonably interfere with oil and gas exploration and production.

[2] — Implied Easement of Surface Use.

[a] — Whether It Would Include CO_2 Disposal Rights.

Most oil and gas leases and some deeds that create a severed mineral estate expressly address the mineral lessee's or mineral estate owner's right to use the premises oil and gas activity. But occasionally these leases or deeds do not address such "surface rights," and a question arises regarding the extent of the surface use rights, if any, that the mineral owner has. In such cases, courts reason that the right to explore for and produce oil and gas generally would be of little value without the right to use the land for those purposes, so the parties must have anticipated that the mineral owner would have such surface rights. It would be unusual for the parties to have intended otherwise, so the parties likely would have expressly restricted the mineral owner's surface use rights if they had intended to limit those rights. Therefore, courts uniformly hold that, if a lease or deed does not expressly address surface use rights, the lessee or mineral estate owner has the right to use the land as reasonably necessary to explore for and produce oil and gas.[75]

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75 Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 218. *See also* Belden & Blake Corp. v. Pennsylvania, 969 A.2d 528, 530 (Pa. 2009) (quoting Chartiers Block Coal Co. v. Mellon, 25 A. 597, 598 (Pa. 1893)).

This right is sometimes called an "implied easement" to use the surface.[76] However, the word "surface" is a bit of a misnomer. In this context, the right to use the "surface" really means the right to use the property of the land—both surface and subsurface. Thus, the "surface use" terminology is analogous to the terminology by which, in the context of severed mineral estates, landowners are often called "surface owners," even though these persons generally own both the surface, as well as the airspace above it and subsurface below it.

The importance of the implied easement of surface use is not limited to instruments—oil and gas leases and deeds that create severed mineral estates—that are silent regarding surface use. If an oil and gas lease or a deed creating a split estate expressly grants certain surface use rights, without expressly restricting the existence of additional surface use rights, courts generally will hold that the mineral owner has an implied easement to use the surface as reasonably necessary, in addition to having the expressly granted surface use rights.[77]

An instructive case from Louisiana that shows this principle is *Leger v. Petroleum Engineers, Inc.*, 499 So. 2d 953 (La. App. 3rd Cir. 1986), which held that a leaseholder had a right to use the surface and subsurface of the leased premises to construct a saltwater disposal well (often, saltwater accompanies oil to the surface and the leaseholder must find a way to dispose of the saltwater), even though the oil and gas lease's granting clause did not expressly include the construction or operation of such a well as an authorized use. An interesting case from Texas is *Sun Oil Co. v. Whitaker*, 483 S.W.2d 808 (Tex. 1972), in which the Texas Supreme Court held that the oil and gas leaseholder had an implied right to use a large amount of freshwater from

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76 Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 218; Key Operating & Equipment, Inc. v. Hegar, 435 S.W.3d 794, 797, 799 (Tex. 2014) (referring to "implied easement to use the surface," to "implied easement of reasonable usage," and to "implied surface easement").

77 Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 218.1 ("It appears that customary surface easements which would be implied had the instrument been completely silent as to surface user will not be negated except by express language to this effect in the instrument.").

the leased premises to support a secondary recovery operation, even though this would inconvenience the lessor and even though the granting clause did not expressly authorize the use of water for secondary recovery.

Knowing this, someone might ask whether a mineral lessee's or mineral owner's implied easement would allow that person to conduct a carbon dioxide disposal operation on the property. In most cases, if the operation is not an enhanced oil recovery operation, and is an operation for disposal only, the answer will be "no." The implied easement might authorize disposal of wastes generated during the production of oil and gas from the property. Thus, as in *Leger*, the implied easement might authorize use of the property for injection disposal of brine produced along with oil and gas recovered from the leased premises or from a unit in which the property is included, but it would not authorize use of the property for disposal of wastes generated from oil and gas activities on other land or for disposal of wastes that are not oilfield wastes.

In most cases in which a company seeks to inject CO_2 for disposal, the CO_2 will not be that a company seeks to inject will not be a waste product from oil and gas operations on the property or land unitized therewith. Some CO_2 may be separated from natural gas during processing, but the volume of the separated CO_2 might not justify a dedicated injection disposal well. Further, processing units often handle gas from multiple properties, so that the stream of separated carbon dioxide would not be a waste that was generated exclusively from the property where an injection disposal well might be located. Further, some carbon dioxide is separated from the oil recovered in an EOR operation that uses CO_2, but the CO_2 that is separated from the recovered oil is generally recycled into the ongoing injection operation. Thus, the implied easement generally will not be sufficient to authorize a CO_2 injection disposal operation.

[b] — Whether It Would Include Right to Conduct EOR That Is Profitable Even Without Considering Any Economic and Tax Benefits Derived from Carbon Sequestration.

The typical oil and gas lease or deed that creates a severed mineral estate does not specify the methods that the lessee or mineral estate owner may use to produce oil and gas. Under the typical lease or deed, the lessee or mineral estate owner will have the right to use any methods reasonably necessary, whether those methods are part of primary recovery operations, secondary recovery operations, or tertiary (enhanced) recovery operations. Thus, if an enhance oil recovery operation is reasonably necessary to produce oil remaining in a particular formation, the lessee or mineral estate owner will have a right to conduct such operations.

Accommodation doctrine issues may arise (but this is true for primary recovery operations too), and a question could be raised as to whether an oil and gas lessee could conduct an operation that is not profitable (or is only profitable after considering revenue earned by incidental CO_2 disposal), but if an EOR operation is profitable when considering only the revenue earned on oil production, there seems little question that the lessee or mineral estate owner generally will have a right to conduct the EOR operations.

[c] — Whether It Would Include Right to Conduct EOR That Is Profitable After Consideration of Economic and Tax Benefits Derived from Carbon Sequestration, but Which Is Not Profitable Otherwise.

An earlier section of this chapter concluded that an oil and gas lessee or mineral estate owner generally would not have a right to conduct an operation to dispose of CO2 if the operation is for disposal only, without also being an enhanced oil recovery operation. However, another earlier section of this chapter concluded that an oil and gas lessee or severed mineral estate owner generally would have a right to conduct an enhanced oil recovery operation

that produces enough oil for the operation to be profit without considering any revenue or economic benefit (such as tax incentives) derived from the EOR operation's incidental sequestration of CO_2.

This leads to a question regarding an intermediate scenario. Suppose that an oil and gas lessee or severed mineral estate owner wishes to conduct an EOR operation that will not produce sufficient oil revenue to be profitable on that revenue alone, but the operation will be profitable considering both oil revenue and economic benefits earned based on the operation's incidental sequestration of carbon dioxide. Would the lessee or mineral owner generally have a right to conduct such an operation? Is such an operation more like an unauthorized waste disposal operation or more like an EOR operation that makes a profit on oil production, while also being able to earn a little extra money on carbon dioxide sequestration that is incidental to the EOR?

Answering this question is difficult because this question has not arisen before. Thus, no existing jurisprudence provides a clear and explicit answer. Further, because this question will be governed by state law, it is possible that different states will resolve the question in different ways. Moreover, there is no guarantee that the answer will be a rule of law that applies in all situations. A jurisdiction might conclude that the question turns on the facts. For example, if an operation's revenue would come primarily from earnings derived from injection disposal, with only small earnings from an incidental amount of oil production, a court might conclude that a lessee or mineral estate owner had no authority to conduct such an operation. On the other hand, if oil revenue alone was nearly sufficient to make the operation profitable, the same court might conclude that the operation was authorized.

Further, in the case of an oil and gas lease, the question of whether an economically "intermediate" operation is authorized might become intertwined with the question of whether the lessee is obligated to pay a royalty on the economic benefits derived from carbon sequestration. To the extent that a lessee is required to pay a royalty, the argument that such operations are authorized is somewhat strengthened.

[3] — Accommodation Doctrine: a Mineral Owner's Obligation to Have Due Regard for the Rights of Others) with an Interest in the Land.

Oil and gas lawyers are accustomed to dealing with the accommodation doctrine, which requires an oil and gas lessee to give due regard to the lessor's existing uses of the leased premises. Similar "due regard" obligations can arise when different persons hold different mineral rights in the same land—such as when one person holds deep oil and gas rights and another person holds shallow rights, or when one person has oil and gas rights and other person has coal rights. If a person has oil and gas rights, while another person has carbon sequestration rights, the person having oil and gas rights might be obligated to give due regard to any existing activity of a carbon sequestration operator.

[4] — When an EOR Project Obtains Economic and Tax Benefits from Carbon Sequestration, Whether a Lessee-Operator Will Owe Royalties to the Lessor on Those Benefits.

Suppose that an oil and gas lease requires the lessee to pay a royalty of 20% on the gross proceeds of the sale of hydrocarbons produced under the lease. The lessee conducts an EOR operation that yields $200 in gross revenue from oil sales, an additional $100 in revenue from unrelated companies that pay the lessee to dispose of their CO_2 (which the lessee uses in its EOR operations on the leased premises), and also $50 in tax credits for the CO_2 sequestered in the EOR operations. There is no question that the lessee will owe a royalty of at least $40 (20% of the $200 in gross revenue from oil sales). But will the lessee also owe a royalty on either or both the $100 that the lessee receives for sequestering the carbon dioxide and the $50 in tax credits.

There are various arguments in support of the proposition that the lessee should not have to pay royalties on the carbon sequestration revenue or tax credits. One such argument is that the typical lease expressly addresses the lessee's royalty obligation, requiring the lessee to pay a royalty on whatever minerals are produced under the lease. The typical lease does not address revenue earned from carbon sequestration or tax credits for such

sequestration. Moreover, the typical lease does not have a catch-all provision that requires a lessee to pay a royalty on any other revenue or economic benefits earned from operations conducted under the lease.

Further, public policy should favor carbon sequestration, and the absence of a royalty obligation will encourage lessees to conduct operations that sequester CO_2. In addition, someone could analogize the sequestration revenue and tax credits to a lessee finding a way to save money on production costs, and probably no one would think that a lessee had an implied duty to pay a royalty on any cost saving methods, even if those methods were unknown at the time the lease was granted.

On the other hand, carbon sequestration revenue and tax benefits are not a form of cost savings. They are a source of revenue or (in the case of a tax credit) at least an economic benefit that is similar to revenue. Further, even if the lessee had to pay a royalty on such revenue and benefits, the lessee still would have an incentive to conduct carbon sequestration because the lessee would keep the bulk of the revenue and benefits (80% in this example). And the lessor would have an incentive to cooperate because it would receive a royalty.

Finally, although the typical lease is silent regarding payment of a royalty on the economic benefits derived from carbon sequestration, the reason for the silence is that this has never been an issue before because no one was earning economic benefits for sequestering carbon dioxide. Oil and gas jurisprudence includes a number of rules that are a designed to foster the presumed purposes of the oil and gas lease—to provide income for both the lessor and lessee, to provide that the lease can continue for a set time and as long thereafter as long as the lessee is active and the lease is profitable, but to provide for lease termination after the set time if the lease is no longer profitable.

Such rules include the implied easement of surface use that benefits lessees, the accommodation doctrine that benefits lessors, the implied covenants that benefits lessors, the implication of a paying quantities requirement into habendum clauses when the literal language does not refer to paying quantities (an implication that benefits lessors), the temporary cessation of production doctrine that can benefit lessees under the rare lease

that does not contain savings clauses, and the discovery rule that benefits lessees in the few states that have adopted the rule. Would it really be a stretch for a court to hold that a lessee owed a royalty on carbon sequestration revenue, tax credits, or both?

Consider *Frey v. Amoco Production Co*., 603 So. 2d 166 (La. 1992). That case was one example of the take-or-pay litigation that erupted between oil and gas lessees and pipelines during the 1980s. There, a lessee had a lease that required it to pay a specified royalty on oil and gas "sales." The lessee entered a contract with a pipeline company that required the company either to *take* (purchase) a minimum quantity of gas from the lessee's production or *pay* a specified amount in lieu of purchasing the minimum quantity. The pipeline company did neither of these things, so the lessee sued for breach of contract. The lessee and pipeline company reached a settlement in which the pipeline company paid some amount to the lessee. The lessor filed suit against the lessee, seeking a royalty on the take-or-pay settlement.

The lessor argued that the entirety of the pipeline company's payment obligations constituted the purchase price for whatever amount of gas the pipeline took.[78] Thus, whenever the pipeline company purchased less than a specified minimum quantity, the purchase price of the gas actually taken included the sum of the "take" obligation and "pay" obligation. Under this rationale, the literal terms of the lease would require a royalty on the pipeline company's payment of money in lieu of taking the specified minimum quantity of gas. Therefore, the settlement paid by the pipeline company was a settlement for underpayment of the sales price. Thus, a royalty was owed. Alternatively, if the pipeline company's obligation to "pay" for a minimum quantity of gas not considered a portion of the price for gas actually taken, the obligation was a substitute for a sale (and therefore a royalty was due on the settlement).

On the other hand, the lessee noted that the settlement payment was not a sale. Thus, under the literal terms of the lease, the lessee should not owe a royalty. Further, because the pipeline company had not taken the gas, the gas

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78 Frey v. Amoco Production Co., 603 So. 2d 166, 177 (La. 1992).

remained in the ground and presumably would be produced and sold later, at which time the lessor would receive a royalty. The lessor would get a double payment if it received a royalty on both the settlement payment that was in lieu of a sale and on the subsequent sale of the gas. The lessee, in contrast, would not receive double revenue because take-or-pay payments made in lieu of a sale merely compensated the lessee for the expense and risk of building its own pipeline to connect to the pipeline company's pipeline.

The Louisiana Supreme Court could have resolved the case in favor of the lessee based on the literal language of the lease by concluding that the settlement was not part of the price for a sale of gas. Alternatively, the Court could have resolved the case in favor of the lessor based on the literal language of the lease by concluding that the pipeline company's entire obligation to pay constituted a portion of the sales price for the amount of gas actually taken. And, the Court stated that it agreed with the lessor that the take-or-pay payment was a part of the sales price, but the Court expressly chose "not to rest our decision on this conclusion alone."[79]

Instead, in holding that the lessor was entitled to a royalty on the take-or-pay settlement, the Court based its opinion in part on its view of oil and gas leases and the lessor-lessee relationship. The Court stated that an oil and gas lease creates a "cooperative venture" in which the lessee contributes expertise and capital, while the lessor contributes its land.[80] Further, "the ultimate objective of the royalty provision of the lease is to fix the division between the lessor and lessee of the economic benefits anticipated from the development of the minerals."[81]

> [W]e conclude an oil and gas lease, and the royalty clause therein, is rendered meaningless where the lessee receives a higher percentage of the gross revenues generated by the leased property than contemplated by the lease. The lease represents a bargained-for exchange, with the benefits flowing directly from the leased

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79 *Id*. at 180.
80 *Id*. at 173.
81 *Id*.

> premises to the lessee and the lessor, the latter via royalty. An economic benefit accruing from the leased land, generated solely by virtue of the lease, and which is not expressly negated, … is to be shared between the lessor and lessee in the fractional division contemplated by the lease.[82]

Thus, even if the take-or-pay proceeds had not been considered part of a sales price, the lessor probably would have been entitled to a royalty on the take-or-pay settlement.

If an oil and gas lessee earns revenue and tax credits from the incidental sequestration of carbon dioxide that results from the EOR operation conducted pursuant to the lease, a strong argument exists that this revenue and the economic value of the tax credits are each an "economic benefit accruing from the leased land, generated solely by virtue of the lease." Therefore, if a court rejected the arguments that a lessee should not owe a royalty, and instead the court followed the logic of *Frey*, the court would hold that a royalty payment was owed.

[5] — If a Royalty Is Owed on Carbon Sequestration Revenue and Economic Benefits, How It Will Be Calculated?

If a lease does not expressly address the payment of royalties on carbon sequestration payments and tax benefits earned from an EOR operation, but a court concludes that a royalty is owed, a question could arise regarding how the royalty is to be calculated. Of course, the royalty payment would be calculated by multiplying a royalty fraction by some amount of money. But what fractional amount and what amount of money?

Every oil and gas lease will state the royalty fraction that the lessee must pay on oil and gas production, and in modern oil and gas leases the royalty typically is the same on both oil and gas. Thus, if a court holds that a royalty is owed on economic benefits derived from carbon sequestration, the court likely would hold that the royalty fraction to be paid on those benefits is the

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82 *Id*. at 174 (internal citation omitted).

same as the royalty fraction used for royalties on oil and gas. Such a holding may or may not be fair. The parties agreed to a particular royalty fraction that anticipated would be used for calculating the royalty owed on oil and gas production. That fraction may or may not be the same fraction to which the parties would have agreed it they had bargained regarding a royalty to be paid on economic benefits from carbon sequestration. Nevertheless, the royalty fraction stated in the lease is probably the fraction that the court would use.

An arguably more difficult question might be the economic value against which the royalty fraction would be multiplied to calculate the amount owed. The typical oil and gas lease specifies the value against which the royalty fraction is multiplied. For oil, the royalty fraction often is a fraction of the oil produced. In practice, one can think of this as being the value the oil had at the surface, after it has been produced. The royalty payment might be calculated by multiplying the royalty fraction against the gross sales price of the oil. Thus, the lessee would absorb the "production" costs associated with getting the oil out of the ground. Those costs would not be deducted from the sales price before multiplying the price by the royalty fraction to calculate the royalty owed.[83] If a deduction of production costs was allowed, the royalty would effectively become a royalty on the value that the discovered, but not yet produced, oil would have while in the ground. Further, there would be no deduction of any post-production costs. Such costs generally are not an issue with respect to oil.

On the other hand, leases often provide that the royalty on gas is to be calculated by multiplying the royalty fraction times the value of the gas "at the well." Again, for the same reason when calculating the royalty on oil, there is no deduction of production costs. But in contrast to oil, post-production costs often are an issue for purposes of calculating the royalty on gas. This is because many leases expressly state that the royalty fraction is to be multiplied

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83 Some leases base the royalty on the proceeds of sale for sales at the well, but the sales proceeds generally should approximate the market value at the well. Also, some leases provide for a royalty to be based on the gross sales proceeds from a sale, even if the gas is not sold at the well, but this has not traditionally been the most typical arrangement as to royalties.

by the value *at the well*, but often there is not a sale at the well. Often, the sale is made at a point away from the well, at some downstream location, after the gas has been sweetened, dehydrated, processed, compressed, and transported.

Thus, the sales price often reflects the value that the gas has at a location away from the well, rather than "at the well," and the sales also reflects the value that the gas has after its quality has been upgraded by treatment, compression, etc., to a quality that is superior to the quality that the gas had at the well. In many jurisdictions, in the absence of a sale of gas at the well, an approved method for estimating the value that the gas had "at the well" is to subtract the lessee's "post-production" costs for such things as sweetening, dehydrating, treating, compressing, and transporting the gas. The royalty fraction is then multiplied against this number.

The significance of the paragraphs immediately above is that the royalty fraction cannot be viewed in isolation. It is only part of what goes into calculating the royalty that is owed. The royalty fraction to which the parties agree in the lease is a fraction that is used to calculate the royalty amount owed by multiplying the fraction by a value that is essentially the gross value of oil or gas at the well. Thus, the royalty fraction is multiplied against a gross value that is higher than the value remaining to the lessee after paying the costs of production. The parties implicitly conclude this is reasonable for calculating the royalty on oil and gas. But that does not necessarily mean that parties would conclude that this it would be reasonable for a lessee to pay a royalty on the gross revenue received from carbon sequestration, even though the lessee has to incur certain costs.

Lessees likely will argue that they do not owe a royalty on carbon sequestration revenue. Further, they may argue that, in the event they owe royalties, the royalties should not be based on the gross value of any economic benefits that they receive from the carbon sequestration associated with an EOR operation. Instead, they might argue, certain costs should be deducted from the carbon sequestration revenue before calculating the royalty. There is not any jurisprudence directly addressing this issue because the issue is new.

Further, existing jurisprudence regarding the use of the workback or netback method to calculate the royalty on natural gas is unlikely to be

helpful because that jurisprudence turns on: the "at the well" language in many leases and many jurisdictions' acceptance of the argument that the workback method is a reasonable way to estimate the value of gas at the well when there is not a sale at the well; the fact that the workback method arguably preserves the same basic economics for lessor and lessee as would be obtained if there was a sale at the well; and, in most jurisdictions that reject the workback method, the courts' conclusion that the implied covenant to market requires the lessee to absorb certain post-production expenses. None of those rationales is applicable in the context of carbon sequestration revenue.

One state—West Virginia—has rejected the workback method on the basis that the royalty clause is ambiguous about whether the lessee is responsible for post-production costs. Arguably, lessors could use a somewhat similar argument in a dispute regarding calculating a royalty on carbon sequestration revenue, but such an argument would seem to have less force in the context of calculating a royalty on carbon sequestration revenue. After all, the royalty clause is not ambiguous about calculation of a royalty on carbon sequestration revenue; it is altogether silent.

[6] — When an EOR Project for a Unit Operation Obtains Economic and Tax Benefits from Carbon Sequestration, Whether the Unit Operator Will Owe Royalties to the Mineral Interest Owners Other Than the Operator's Lessee.

If a company conducts an EOR operation for a compulsory or voluntary unit, the unit may contain tracts of land for which the company does not have a lease. The company—the operator—will be obligated to allocate a share of production to each tract in the unit, and the person or persons owning mineral rights for those units may be entitled to a payment that is based on the value of minerals allocated to the person's tract. But would the owner of such unleased mineral interests be entitled to a share of any revenue that the operator might receive for carbon sequestration that is incidental to the EOR operation? The parties may have agreed to a unit agreement, a joint operating agreement, or both, but it is unlikely that such agreements will expressly address revenue obtained from carbon sequestration. Further, if

the unit is a compulsory unit, there will be a unit order from the oil and gas conservation agency, but existing unit orders are not likely to expressly address the possibility of revenue from carbon sequestration.

Thus, neither a contract nor a unit order is likely to expressly state whether non-operators are entitled to a share of carbon sequestration revenue. The question of whether the owners of unleased interests are entitled to a share of such revenue will be somewhat similar to the question of whether a lessor is owed a royalty on carbon sequestration revenue. Some of *Frey*'s reasoning about the relationship of oil and gas lessors and lessees will not be applicable, but there are some analogies between the relationship of unit operator to non-operator mineral interests and the relationship of lessee to lessor.

Indeed, in some ways, the argument for a sharing of such revenue is stronger in the context of a compulsory unit. In a compulsory unit, a regulatory order grants an operator to conduct operations for the entire unit, including tracts where the operator has no lease. This is justified because the unit operations will result in greater overall recovery, which can then be shared. Further, the operating rights of the various tract owners in the unit are not simply taken. In effect, the property rights of each individual tract owner is altered by a regulatory *quid pro quo* in which the tract owner loses the right to conduct operations for a particular formation beneath his or her land (and someone else gains such a right) in exchange for the tract owner getting a share of revenue from the operator's operations, even to the extent those operations are conducted elsewhere in the unit. To the extent that the order creating the unit effectively enables the unit operator to obtain both oil revenue and revenue from carbon sequestration, a strong argument exists that, in fairness, all of the owners of working or mineral interests in the unit should share in all the revenue, after some deduction of costs.

On the other hand, counterarguments certainly exist. For example, public policy should favor carbon sequestration and the absence of an obligation for operators to share sequestration revenue might incentivize sequestration.

[7] — If the Only Production Under a Lease Is an EOR Project That Is Profitable When Economic or Tax Benefits Associated with Carbon Sequestration Are Considered, but the EOR Operation Would Not Be Profitable in the Absence of Those Benefits, Whether the Lease Has Production in Paying Quantities.

The typical oil and gas lease contains a "habendum clause" stating that the lease will last a specified period that often is called the "primary term"[84] and as long thereafter as there is "production" or "production in paying quantities" from the leased premises.[85] It appears to be a universal jurisprudential rule that, for purposes of the habendum clause, "production" is interpreted as meaning "production in paying quantities." Thus, to keep a lease alive into the "secondary term," the lessee generally must establish production in paying quantities.[86] The legal question of what constitutes "production in paying quantities" is a complex one that can occupy entire law review articles and continuing legal education presentations. However, the basic idea is that a well is producing oil and gas in paying quantities if the ongoing operating revenue from the well exceeds the ongoing operating costs associated with the well.[87]

A lessor could mount a strong argument that if revenue from oil and gas production alone is not sufficient for operating revenue to exceed operating costs, the fact that the lease may be profitable if both oil revenue and carbon sequestration revenue are considered does not mean that the lease has

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84 The primary term typically is a few years in length, though parties sometimes agree to shorter or longer primary terms.

85 Production from land pooled or unitized with all or a portion of the leased premises also typically will suffice to keep the lease alive beyond the primary term.

86 Most oil and gas leases contain one or more "savings clauses" that will prevent the lease from immediately terminating in the absence of production in paying quantities after the end of the primary term, but the general rule is that production in paying quantities is needed.

87 In some jurisdictions, even if operating expenses exceed operating revenue, a well is considered to be producing in paying quantities if there is a reasonable expectation that operating revenue will exceed operating costs in the future.

production in paying quantities. After all, carbon sequestration revenue is not *production* revenue. Thus, carbon sequestration revenue should not maintain a lease.

If the lessee is not obligated to pay a royalty on carbon sequestration revenue, an additional argument exists on the lessor's side. Courts have stated that the purpose of the paying quantities requirement is to serve the purpose of the lease. They explain that the reason for the lease is to promote the joint economic interests of the lessor and lessee. Further, the lessor's motivation in granting the lease and allowing someone to have operational rights is the hope of obtaining a royalty. The reason that leases evolved to have a relatively short primary term, and to include a habendum clause that allowed a lease to be maintained into a secondary term if, but only if there is production (putting savings clauses aside for a moment), is to cause the lease to end if there is not production within a reasonable time (the justification for the relatively short primary term) or to cause it to end as soon as production ceases. The lessor would not have intended for the lease to survive and for the lessee to continue to have operating rights simply because of a small amount of production that does not even produce enough revenue to cover the lessee's ongoing operating costs.[88] Thus, a quantity of production that is not sufficient to cover operating costs will not keep the lease alive after the primary term is over. If a lessee is not obligated to pay royalties on carbon sequestration revenue, the same rationale that justifies the paying quantities requirement would favor a conclusion that carbon sequestration revenue is not considered in the paying quantities calculation.

Again, a counterargument is that public policy should favor carbon sequestration, and a contrary result could incentivize lessees to engage in EOR that results in sequestration of carbon dioxide.

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[88] This can be modified somewhat by reasoning that the requirement is satisfied if either operating revenue exceeds operating costs or there is a reasonable expectation that operating revenue will begin to exceed operating costs.

§ 7.04. Conclusion.

Carbon capture and storage is gaining increased attention. The person who generally will have a right to conduct or authorize subsurface sequestration of carbon dioxide is the landowner. This is true even if someone other than the landowner holds a severed mineral interest in the land. There is some legal authority that could be used by a storage operator to argue that it could use the subsurface for carbon sequestration even if the operator does not obtain rights from the landowner. However, it would be unwise for a storage operator to rely on that authority because it is unclear that such arguments would prevail.

There are a few ways that an operator could acquire rights to use the subsurface for storage. One is through voluntary negotiations with the landowner. In some states, an alternative exists. Some states authorize a carbon sequestration operator to acquire subsurface storage right through an eminent domain process or through a process that is similar to oil and gas pooling or unitization.

A storage operation will raise several issues in the event someone other than the landowner holds oil and gas operating rights. These issues include application of the accommodation doctrine and an oil and gas lessee's implied easement to use the leased premises. Further, if an oil and gas operator is conducting an enhanced oil recovery operation and is obtaining revenue from the incidental sequestration of carbon dioxide, that can raise issues regarding royalties and lease maintenance. Similarly, if a unit operator is conducting an EOR project and is obtaining revenue from the incidental sequestration of carbon dioxide, that can raise issues regarding the compensation owed to the owners of unleased mineral interests in the unit.

Chapter 8

Federal Regulatory Frameworks for Carbon Capture Utilization and Sequestration

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§ 8.01. Introduction.

[1] — What Is CCUS and Why Discuss It Now?

Broadly stated, carbon capture, utilization and sequestration (CCUS) is a tool for reducing the carbon intensity of global energy and industrial systems in order to mitigate the impacts of climate change. In the United States, businesses of all kinds are under significant and growing pressure from banks, shareholders, customers and governments to reduce their carbon emissions. The financial community has been particularly focused

in this area and has been a leading force toward decarbonization. On the customer
front, buyers of goods and services, themselves often under pressure to decarbonize, have indicated a preference for lower-carbon products, including energy. State public utility regulators in many states are implementing polices to require or incentivize electricity utilities to reduce emissions associated with power generation.

CCUS is a suite of technologies and physical infrastructure that can be deployed to achieve decarbonization objectives. A variety of technologies, many of which are commercially available today, can be used to capture carbon dioxide from sources such as power generation, industrial processes such as cement and steel making, chemical manufacturing, ethanol production, hydrogen production, and others, and even directly from the atmosphere, through direct air capture.

Once captured, the carbon dioxide can be transported via pipelines, often in a liquid "supercritical" form, to points of sequestration. There are some 4,600 miles of carbon dioxide pipelines already in operation in the U.S., mostly to supply carbon dioxide for Enhanced Oil Recovery, with a track record of safe operations. A number of new carbon dioxide pipeline projects are planned-both for Enhanced Oil Recovery (EOR) and CCUS purposes.

The carbon dioxide is then injected into Environmental Protection Agency (EPA) or state-permitted deep wells for permanent geologic sequestration in suitable underground formations, or into oil and gas reservoirs to increase production.

This chapter summarizes key federal regulatory frameworks applicable to CCUS, with a focus on federal programs that may affect project design, siting, timelines and, ultimately, economics.

Some of these frameworks are well-known to energy and environmental lawyers, and appear unlikely to present significant obstacles to the expansion of CCUS. Other regulatory frameworks, or their absence, may present uncertainty or challenges that stakeholders may wish to address in

order to attract financing and advance projects. This chapter builds on the work of a number of scholars who provide a more detailed treatment of several of the key regulatory issues around carbon dioxide pipelines.[1]

§ 8.02. Federal Frameworks.

[1] — Pipeline Siting and Rate Regulation.

A large interstate carbon dioxide pipeline network will be necessary to support national CCUS efforts. With the exception of carbon dioxide pipelines crossing federal lands, or those seeking financial support from the Department of Energy (DOE), there is no federal regulatory program for onshore carbon dioxide pipeline siting or rate regulation. Interstate carbon dioxide pipeline developers must navigate a patchwork of state regulation when siting a new facility. Some states require carbon dioxide pipelines to be common carriers-providing open access to the public, others provide eminent domain for carbon dioxide pipeline siting, sometimes in exchange for a commitment to be a common carrier.[2] Many other states have not yet grappled with carbon dioxide pipeline regulation. Construction of a larger interstate carbon dioxide pipeline network may require further regulatory development around siting and rate regulation. The key question is whether such a buildout is better supported through state or federal regulatory frameworks. There is a diversity of opinion on this question. Some stakeholders point to the successful track record of carbon dioxide pipeline

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1 Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 Energy L.J. 85 (2009); Tara K. Righetti, *Siting Carbon Dioxide Pipelines*, 3 Oil and Gas, Nat. Res. & Energy L.J. 907 (2017); Kris Koski, Jesse J. Richardson, Jr., Tara K. Righetti, Dr. Sam Taylor, *Study on States' Policies and Regulations per CO2-EOR-Storage Conventional, ROZ and EOR in Shale: Permitting, Infrastructure, Incentives, Royalty Owners, Eminent Domain, Mineral-Pore Space, and Storage Lease Issues*, U.S. Energy Assoc. (Sept. 2020) (available at https://usea.org/sites/default/files/Study%20on%20States%E2%80%99%20Policies%20and%20Regulations%20per%20CO2-EOR-Storage%20%281%29.pdf).

2 Tara K. Righetti, *Siting Carbon Dioxide Pipelines*, 3 Oil and Gas, Nat. Res. & Energy L.J. 907 (2017)

buildout so far, while others express concern that differences between state regulatory approaches will hinder the expansion of an interstate network.

[a] — FERC and ICC Disclaimers of Jurisdiction.

Both the Federal Energy Regulatory Commission (FERC) and the Interstate Commerce Commission (ICC) have considered and disclaimed jurisdiction over carbon dioxide pipelines. Their conclusions rested on analyses of the terms "natural gas" and "gas" in their respective statutory authorities.

FERC has considered its jurisdiction over carbon dioxide pipelines under the Natural Gas Act (NGA).[3] The NGA provides FERC with jurisdiction over the siting and rates and charges for interstate natural gas pipelines.[4] Natural gas pipeline operators must obtain a certificate of public convenience and necessity in order to site and construct an interstate gas pipeline,[5] and the NGA provides a right of eminent domain to certificate holders.[6] In 1979, the Cortez Pipeline Company filed a petition for declaratory order at FERC seeking clarification that the agency lacked jurisdiction over a carbon dioxide pipeline because it was not transporting "natural gas" under the NGA.[7] Relying on the legislative history of the NGA, and concluding that Congress was focused on regulation of gases used as fuel, FERC agreed with Cortez and found that it did not have jurisdiction.[8] FERC tacitly reaffirmed this lack of NGA jurisdiction in a 2006 *Southern Natural Gas Co*. case.[9]

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3 15 U.S.C. § 717; Cortez Pipeline Co., 7 FERC ¶ 61,024 (1979); Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 ENERGY L.J. 85 (2009).

4 15 U.S.C. §§ 717, 717c, 717f(h).

5 15 U.S.C. § 717f.

6 15 U.S.C. § 717f(h).

7 Cortez Pipeline Co., 7 FERC ¶ 61,024, p. 61,040 (1979).

8 *Id*. at 61,041 – 61,042

9 Southern Nat. Gas Co., 115 FERC ¶ 62,266 (2006).

At around the same time as the *Cortez* FERC order, the Cortez Pipeline Company also petitioned the Interstate Commerce Commission (ICC) for a declaratory order that it too lacked jurisdiction over carbon dioxide pipelines under the Interstate Commerce Act (ICA).[10] The ICA provides for light-handed economic regulatory jurisdiction over certain kinds of common carrier interstate pipeline transportation of commodities "other than water, gas or oil."[11] Unlike FERC's authority under the NGA, the ICA does not provide pipeline siting or eminent domain authority.[12] The ICC, a predecessor agency to FERC and Surface Transportation Board (STB), determined that "all gas types" were excluded from ICA jurisdiction.[13]

[b] — Surface Transportation Board's Role.

Some have suggested that the STB could take a different approach than the ICC, and could assert jurisdiction over carbon dioxide pipelines.[14] In a 1998 report, the General Accounting Office (GAO) observed that the STB had jurisdiction over interstate carbon dioxide pipelines.[15] The GAO did not undertake an analysis of the basis for this position.[16] In a 2008 Congressional Research Service (CRS) report, the authors followed up with

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10 Cortez Pipeline Co. – Petition for Declaratory Order – Commission Jurisdiction Over Transportation of Carbon Dioxide by Pipeline, 45 Fed. Reg. 85,177 (Dec. 24, 1980).

11 49 U.S.C. § 15301(a).

12 Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 Energy L.J. 85, 92-93 (2009).

13 Cortez Pipeline Co. – Petition for Declaratory Order – Commission Jurisdiction Over Transportation of Carbon Dioxide by Pipeline, 45 Fed. Reg. 85,177, 85,178 (Dec. 24, 1980).

14 U.S. Gov't Accountability Office, GAO-RCED-98-99, SURFACE TRANSPORTATION: Issues Associated with Pipeline Regulation by the Surface Transportation Board (1998); Adam Vann and Paul W. Parfomak, Cong. Research Serv., RL34307, Regulation of Carbon Dioxide (CO2) Sequestration Pipelines: Jurisdictional Issues (2008); Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 Energy L.J. 85, 92-93 (2009).

15 U.S. Gov't Accountability Office, GAO-RCED-98-99, SURFACE TRANSPORTATION: Issues Associated with Pipeline Regulation by the Surface Transportation Board (1998).

16 *Id.*

the STB on its position regarding carbon dioxide pipeline jurisdiction.[17] According to the CRS report, the STB explained that it recognized the tension between the 1998 GAO report and the ICC's 1980 *Cortez* decision, but declined to take a position on the extent of its jurisdiction.[18] The STB suggested that it was unlikely to resolve this issue outside of a specific carbon dioxide pipeline jurisdictional dispute brought before it.[19] To date, no such disputes have been reported by the STB. Other commenters have suggested that the ICC's 1980 analysis of its ICA authority and related legislative history does not support its conclusion that all gases are excluded, and that a similar conclusion today might not withstand judicial review.[20]

[c] — Bureau of Land Management Right-of-Way Regulation.

Onshore carbon dioxide pipelines that cross federal lands are subject to federal siting and common carrier regulation. Under the Minerals Leasing Act (MLA) the Bureau of Land Management (BLM) may grant rights-of-way for pipelines transporting "natural gas" and other commodities.[21] While "natural gas" and "gas" in other statutory contexts, such as under the NGA and ICA, has been found to exclude carbon dioxide, the BLM found, and the 10th Circuit agreed, that this term is not so limited under the MLA.[22] A carbon dioxide pipeline with an MLA right-of-way is required to provide common carrier service.[23]

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17 Adam Vann and Paul W. Parfomak, Cong. Research Serv., RL34307, Regulation of Carbon Dioxide (CO2) Sequestration Pipelines: Jurisdictional Issues (2008).

18 *Id.*

19 *Id.*

20 Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 Energy L.J. 85, 92-93 (2009).

21 30 U.S.C. § 185(a).

22 Exxon Corp v. Lujan, 970 F.2d 757 (10th Cir. 1992).

23 30 U.S.C. § 185(r).

[d] — Infrastructure Investment and Jobs Act.

Another potential source of common carrier regulation comes from the recently enacted, bi-partisan Infrastructure Investment and Jobs Act (Infrastructure Act).[24] The Infrastructure Act authorizes a new program within the Department of Energy (DOE) that will provide financial incentives, including loan guarantees and certain infrastructure expansion grants to carbon dioxide pipeline developers.[25] Carbon dioxide pipeline developers that participate in this DOE program must provide common carrier transportation service, regardless of whether the pipeline would cross federal lands.

[2] — Federal Regulation of Pore Space.

Ownership rights of subsurface pore space is another key element necessary to support construction of a national CCUS network. Pore space consists of the subsurface voids within which carbon dioxide is injected for storage. There may be federal regulation for the use of pore space on federal lands,[26] but the matter of pore space ownership beneath private lands is a matter of state statutory or common law.[27] This issue is addressed in more detail in Chapter 9.[28]

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24 Pub. L. 117-58, Sec. 40304.

25 *Id.*

26 Kris Koski, Jesse J. Richardson, Jr., Tara K. Righetti, Dr. Sam Taylor, *Study on States' Policies and Regulations per CO2-EOR-Storage Conventional, ROZ and EOR in Shale: Permitting, Infrastructure, Incentives, Royalty Owners, Eminent Domain, Mineral-Pore Space, and Storage Lease Issues*, U.S. Energy Assoc. (Sept. 2020) (available at https://usea.org/sites/default/files/Study%20on%20States%E2%80%99%20Policies%20and%20Regulations%20per%20CO2-EOR-Storage%20%281%29.pdf) at p. 10-11.

27 *Id. at 123.*

28 Keith B. Hall, *Property Law and Oil & Gas Issues Raised by Carbon Capture and Storage*, 42 Energy & Min. L. Inst. §7 (2022).

[3] — Pipeline Safety.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) and its state partners administer a national safety regulatory and enforcement program that applies to pipelines transporting carbon dioxide.[29] PHMSA has regulated liquid phase (supercritical) carbon dioxide pipelines since the early 1990s and these pipelines generally have a good safety record.

In 1988, Congress directed PHMSA to regulate the transportation of carbon dioxide by pipeline citing concerns with the potential localized asphyxiant effects of carbon dioxide if released.[30] In 1989, the American Petroleum Institute (API) petitioned PHMSA to amend the existing pipeline safety regulations in 49 C.F.R. Part 195 applicable to hazardous liquid pipelines to include carbon dioxide pipelines—rather than create a new set of regulations just for carbon dioxide pipelines.[31] PHMSA adopted API's proposed approach and amended Part 195 in 1991 to apply to the transportation of carbon dioxide in a supercritical liquid state.[32] While there are a few differences, pipeline transportation of carbon dioxide is largely subject to the same set of safety regulations that apply to oil, refined products and other hazardous liquid pipelines. These regulations include design,

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[29] 49 U.S.C. § 60101 *et seq.* States may submit an annual certification to PHMSA to administer a pipeline safety program for intrastate pipeline facilities, and most states have done so for gas pipelines. For liquids pipelines, 15 states have certifications. Appendix F- State Program Certification/Agreement Status CY 2021, Pipeline and Hazardous Materials Safety Administration (Dec. 2020) (available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-03/2021%20Appendix%20F%20-%20State%20Program%20Certification%20Agreement%20Status_0.pdf.

[30] Pipeline Safety Reauthorization Act of 1988 § 211, 102 Stat. 2805, 2813 (Oct. 31, 1988). *See also* Transportation of Carbon Dioxide by Pipeline, Notice of Proposed Rulemaking, 54 Fed. Reg. 41,912, 49,913 (Oct. 12, 1989) (discussing the history behind Congress's mandate).

[31] *See* Transportation of Carbon Dioxide by Pipeline, Notice of Proposed Rulemaking, 54 Fed. Reg. 41,912, 49,913-14 (Oct. 12, 1989).

[32] Transportation of Carbon Dioxide by Pipeline, Final Rule, 56 Fed. Reg. 26,922 (June 12, 1991). *See also* Transportation of Carbon Dioxide by Pipeline, Notice of Proposed Rulemaking, 54 Fed. Reg. 41,912 (Oct. 12, 1989).

construction, testing, operations and maintenance, integrity management, control room management, operator qualification and others.[33]

In 2011, anticipating a potential increase in CCUS activities in the U.S., Congress expanded PHMSA's authority to include pipelines transporting carbon dioxide in the gaseous phase.[34] PHMSA has yet to exercise that authority. In 2016, PHMSA published a request for comments seeking information on the necessity for and approach to regulating gas-phase carbon dioxide pipelines.[35] In that request for comments, the Agency noted that it had been "unable to identify specific gaseous carbon dioxide pipelines or pipeline operators that would potentially be subject to future regulation."[36] The Agency identified only one 78-mile low-pressure gaseous carbon dioxide pipeline located in a gas gathering field.[37]

Along with the request for comments, PHMSA published a report titled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State."[38] The report set out the history of carbon dioxide pipeline regulation, the differences between transporting carbon dioxide in a liquid or gaseous state, potential threats of transporting carbon dioxide in a gaseous state by pipeline, and potential regulatory approaches. The report provided that pipelines transporting carbon dioxide in a gaseous state are not subject to either the gas pipeline safety regulations in 49 C.F.R. Part 192, or Part 195, as those code sections are currently written.[39] The Agency recognized in the Report that the increase in carbon capture and

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33 49 C.F.R. Part 195 (2020).

34 Pipeline Safety, Regulatory Certainty, and Job Creation Act, Pub. L. 112-90 § 15, 125 Stat. 1904, 1915 (Jan. 3, 2012) (codified at 49 U.S.C. § 60102(i)(2)).

35 Pipeline Safety: Gaseous Carbon Dioxide Pipelines, 81 Fed. Reg. 41,647 (July 27, 2016).

36 *Id.* at 41,648.

37 *Id.*

38 Pipeline & Hazardous Materials Safety Admin. and U.S. Dept. of Transportation, Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State (2015) (available at https://www.regulations.gov/document/PHMSA-2016-0049-0001).

39 S*ee, e.g.*, *id.* at 2-3, 15.

sequestration projects in the future may result in an increase in gaseous carbon dioxide pipelines. To date, PHMSA has not proposed to regulate pipelines transporting carbon dioxide in a gaseous state.

While it seems that most carbon dioxide is transported by pipeline in the liquid, supercritical phase, if CCUS projects become more common it is possible that some will involve gas-phase transport. If this occurs PHMSA may react with a proposed rulemaking to regulate these facilities.

[4] — Key EPA Programs.

[a] — Class VI Underground Injection Control Permits.

The EPA plays a significant role in the regulation of CCUS projects. In 2010, pursuant to the Safe Drinking Water Act (SDWA) EPA issued a final rule adding a new type of permitted well to its Underground Injection Control (UIC) program specifically for permanent geologic sequestration of carbon dioxide.[40] The agency added this new well type, referred to as a Class VI UIC well, in response to the anticipated need for large amounts of permanent carbon dioxide storage.[41] The Class VI UIC program builds on EPA's other UIC programs, including the Class II UIC well program that is used for, among other activities, the injection of carbon dioxide for enhanced oil recovery.[42]

EPA's Class VI requirements are designed to protect underground sources of drinking water and address site characterization, modeling of injected carbon dioxide movement, construction, operation, testing,

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40 Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 75 Fed. Reg. 77,230 (Dec. 10, 2010).

41 *Id.* at 77,233-77,234.

42 Class II Oil and Gas Related Injection Wells, EPA (Sept. 14, 2021), https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells.

monitoring and post-injection closure.[43] EPA's Class VI regulations also require facility owners and operators to obtain financial instruments to cover the cost of corrective action, plugging, post-injection site care and closure, and emergency and remedial response.[44] There are two currently active EPA-issued UIC Class VI well permits and four applications for new permits pending.[45] The EPA has granted other Class VI permits in the past but they are no longer in effect.[46] There are also state Class VI UIC permits that have been issued or are pending in states with Class VI primacy.[47]

A key issue for carbon dioxide project developers is the significant amount of time necessary to obtain a Class VI well permit. Past Class VI wells have taken five or more years to permit.[48] If permit timelines are not reduced, project financing may be more difficult to obtain. Perhaps reflecting this difficulty, there have been recent federal and state efforts to expedite Class VI UIC permitting. Two states, North Dakota and Wyoming, have obtained primacy from EPA to administer Class VI UIC programs.[49] A number of other states have taken steps toward obtaining

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43 Class VI- Wells used for Geologic Sequestration, EPA (January 20, 2022), https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2; *see* 40 C.F.R. §§ 146.81 – 146.95 (Subpart H).

44 40 C.F.R. § 146.85(a)(2).

45 Class VI Well Permits Issued by EPA, EPA (February 15, 2022), https://www.epa.gov/uic/class-vi-wells-permitted-epa.

46 The FutureGen Alliance applied for and obtained four EPA Class VI UIC permits in 2015 for a CCS project associated with a coal-fired power station in Illinois. *See* FutureGen 2.0 Class VI UIC Permit Application, EPA (February 21, 2016), https://archive.epa.gov/region5/water/uic/futuregen/web/html/. The project was cancelled in 2016.

47 *See* Class VI Wells, North Dakota Department of Mineral Resources (February 16, 2022), https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp. The Wyoming Class VI UIC program was recently established and permits have not yet been issued. *See* Class VI Wells, Wyoming Department of Environmental Quality (February 16,2022), https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/.

48 Bob Van Vorhees, Sallie Greenberg, and Steve Whittaker, Observations on Class VI Permitting: Lessons Learned and Guidance Available, Special Report 9 at p.9, Illinois State Geological Survey (2021), https://library.isgs.illinois.edu/Pubs/pdfs/specialreports/sp-09.pdf.

49 ND Admin. Code 43-05; WY Code of Rules, Chapter 24.

Class VI primacy, including Texas, Louisiana and West Virginia. Some stakeholders believe that state administration of the Class VI program will result in a faster permitting process,[50] as many states have substantial experience from years of administering programs for the various other UIC well types. At the federal level, the recently enacted Infrastructure Act includes $50 million in funding for EPA's Class VI UIC program, and an additional $50 million for a new grant program for states that adopt the Class VI program.[51]

[b] — Greenhouse Gas Reporting.

EPA administers three greenhouse gas reporting programs related to CCUS. These programs require measurement and reporting at the site of carbon dioxide capture as well as at the location where carbon dioxide is injected into a subsurface geologic formation for permanent storage or for enhanced oil recovery. The agency's subpart PP program requires that facilities used to capture carbon dioxide in order to sequester or otherwise inject it into a geologic formation report the mass of carbon dioxide captured on an annual basis.[52] This program sets out requirements for how to measure and calculate the mass of carbon dioxide captured, what information to report, and what data must be retained.[53]

At the point of permanent sequestration, EPA's subpart RR regulations require reporting of the mass of carbon dioxide injected,[54] and they require additional monitoring, reporting and verification (MRV) to confirm that the carbon dioxide remains sequestered.[55] The MRV requirements are

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50 *See* Jena Lococo, *The Permitting Program Crucial for Carbon Capture's Success,* Clearpath (Mar. 11, 2021), https://clearpath.org/our-take/the-permitting-program-crucial-for-carbon-captures-success/.

51 Pub. L. 117-58, Sec. 40306.

52 40 C.F.R. Part 98, subpart PP.

53 *Id.*

54 40 C.F.R. Part 98, subpart RR.

55 40 C.F.R. § 98.448.

more complex than those at the capture site, given EPA's interest in the long-term integrity of geologic storage.[56] The reporting information is also used by the Internal Revenue Service (IRS) for purposes of calculating the federal 45Q tax credit for carbon sequestration.[57] Reporting accuracy and documentation is particularly important given the critical nature of the 45Q credit to the economics of most, if not all, carbon capture and sequestration projects. A detailed discussion of the 45Q tax credit and related IRS issues is found in Chapter 8.[58]

Beyond the Subpart PP and RR regulations, EPA also administers the subpart UU regulations, which are similar in some respects to subpart RR, and require reporting of carbon dioxide injected into an oil or gas reservoir for enhanced recovery.[59] The subpart UU regulations do not require the detailed MRV provisions included in subpart RR.

[5] — Other Federal Regulatory Programs.

Developers of carbon dioxide pipelines may face many of the same federal regulatory programs that one encounters when developing an oil or gas pipeline. For example, carbon dioxide pipeline developers will likely need Clean Water Act Section 404 permits for waterbody and wetland crossings, including crossings located on private land. Developers might seek individual permits or, where discharges have only minimal adverse effects, they may seek to use Nation Wide Permit (NWP) 58.[60] NWP 58 is a new permit that the U.S. Army Corps of Engineers issued in 2021, which specifically applies to utility lines

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56 Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, Final Rule, 75 Fed. Reg., 75,060 (Dec. 1, 2010).

57 26 U.S.C. § 45Q(f).

58 Michael L. Platner, 45Q Carbon Sequestration Tax Credit Summary, 42 Energy & Min. L. Inst. § 6 (2022).

59 40 C.F.R. Part 98, subpart UU.

60 Reissuance and Modification of Nationwide Permits, Final Rule, 86 Fed. Reg. 2,744 (Jan. 13, 2021)

that convey water and other substances, other than oil and gas, which will continue to be covered under NWP 12.[61] For carbon dioxide pipelines crossing federal lands, BLM may need to conduct an analysis under the National Environmental Policy Act (NEPA), and produce an environmental assessment or environmental impact statement before issuing a right-of-way.[62] The National Historic Preservation Act (NHPA) may also impose consultation obligations on federal agencies issuing other permits and authorizations for a carbon dioxide pipeline that could impact a historic or cultural property.[63] And if a proposed carbon dioxide pipeline could impact a threatened or endangered species or its habitat, the developer must consult with the U.S. Fish and Wildlife (FWS) service, and may be required to obtain additional permits.[64]

§ 8.03. Conclusion.

Many of the same federal regulatory programs that apply to oil and gas pipelines, will also apply in some form to carbon dioxide pipelines. Areas for potential future pipeline regulatory development involve economic regulation and siting. Aside from carbon dioxide pipelines on federal lands, pipelines are currently subject to a patchwork of state requirements. Thus far, this patchwork does not appear to have resulted in significant impediments for the existing U.S. carbon dioxide pipeline network. Stakeholders may wish to consider whether the status quo is preferable to a new, uniform federal program for carbon dioxide pipeline economic and siting regulation. With respect to geologic sequestration of carbon dioxide, a key area for potential improvement is the Class VI UIC program. The permitting timeframes for

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61 *Id.*

62 40 C.F.R. Parts 1500-1508.

63 36 C.F.R. Part 800.

64 16 U.S.C. § 1531 *et seq.*

Class VI permits have been lengthy and if they do not become more efficient, could hinder the development of a national carbon dioxide pipeline network.

Chapter 9

Hydrogen Rising: Opportunities and Obstacles for a Hydrogen Economy at Scale

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§ 9.01. Introduction.

The world is abuzz about hydrogen. With a zero emissions combustion profile, attention on this small but mighty molecule has increased significantly as countries around the globe look to implement strategies to reduce greenhouse gas ("GHG") emissions and slow or stop the impacts of climate change. While hydrogen will not revolutionize all sectors of the energy economy, it offers significant potential to reduce emissions in certain sectors where emissions reductions are the hardest to achieve.

Despite the more recent spotlight on hydrogen, the United States has been using hydrogen for over 80 years and currently produces approximately ten million metric tons of hydrogen per year.[2] The majority of this hydrogen is

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1 With special thanks to Sara Hall and Brian Hopkins for their research assistance and contributions to this chapter.

2 *See Hydrogen Production*, Dep't of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-production (last visited July 12, 2021).

used in petroleum refining, agricultural fertilizer, and industrial applications. Global demand for hydrogen currently is estimated around 70 million metric tons per year.[3] However, many believe that this will change significantly and quickly.

Analysts at the multinational bank Barclays estimate that by 2050 the global hydrogen economy could reach one trillion dollars, "potentially saving 5 gigatonnes in CO_2 emissions a year."[4] The Hydrogen Council, a CEO-led global initiative with the ambition "for hydrogen to foster the clean energy transition for a better, more resilient future,"[5] has stated that "hydrogen could account for almost one-fifth of total final energy consumed by 2050."[6]

As we stand on the precipice of the potential development of local, regional, national, and even a global hydrogen economy, this chapter explores the United States' history with hydrogen, how hydrogen is produced, potential uses for hydrogen, and some of the challenges that the industry may face as it looks to move towards scale.[7]

§ 9.02. History with Hydrogen.

Although renewed interest in hydrogen as an energy source at scale is fairly recent, the United States has explored developing a hydrogen economy for several decades. This is evidenced by several significant pieces of federal legislation over the years, including:

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3 International Energy Agency, The Future of Hydrogen at 17 (available at https://www.iea.org/reports/the-future-of-hydrogen).

4 Hydrogen Council, Hydrogen Scaling Up (2017) (available at https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf).

5 Hydrogen Council, https://hydrogencouncil.com/en/ (last visited July 12, 2021).

6 Hydrogen Council, Hydrogen Scaling Up (2017) (available at https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf).

7 For a more in-depth analysis of these and other legal, regulatory, commercial, and policy issues associated with hydrogen, please see K&L Gates' free publication: The H_2 Handbook, which includes chapters on the United States, Australia, the European Union, France, Germany, Japan, [the Middle East,] Singapore, and the United Kingdom. The H_2 Handbook is available at: www.klgates.com/The-Hydrogen-Handbook. K&L Gates is also proud to share Hydrogen Rising, our bi-weekly podcast focused on hydrogen. Hydrogen Rising is available at: www.klgates.com/Hydrogen-Rising and on your favorite podcast app.

- The Electric and Hybrid Vehicle Research, Development and Demonstration Act of 1976,[8] which authorized the Hydrogen Program, discussed in greater detail below;
- The Energy Policy Act of 1992, which directed the Secretary of Energy to develop and implement research and development and demonstration programs focused on fuel cells;[9]
- The Hydrogen Future Act of 1996, which directed the Secretary of Energy to establish the terms and conditions of funding for research and development and demonstration programs and, importantly, also authorized approximately 1.7 billion dollars in appropriations for these efforts between 1996 and 2001;[10] and
- The Energy Policy Act oyf 2005 ("EPAct 2005"), which called for research and development in hydrogen production, delivery, infrastructure, storage, fuel cells, and end uses.[11] Among other significant provisions, EPAct 2005 directed the U.S. Department of Energy's ("DOE") Hydrogen and Fuel Cell Technologies Office ("HFTO") to lead those efforts[12] and included a number of hydrogen-related provisions.[13]

As noted, the Electric and Hybrid Vehicle Research, Development and Demonstration Act of 1976 authorized the Hydrogen Program. At the time, the National Science Foundation was designated to manage the Hydrogen Program. Today, the Hydrogen Program is led by the DOE's HFTO within the Office of Energy Efficiency and Renewable Energy.[14] Through the

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8 *See* Electric Vehicle Research, Development, and Demonstration Act, Pub. L. No. 94-413, 90 Stat. 1260 (1976).

9 *See* Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776.

10 *See* Hydrogen Future Act of 1996, Pub. L. No. 104-271, 110 Stat. 3304.

11 *See* Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

12 *See id.* at Pub. L. No. 109-58, §806, 119 Stat. 594, 808.

13 *See, e.g.*, *id.* at Pub. L. No. 109-58, §634, 119 Stat. 594, 790; *id.* at tit. VII, which includes a number of provisions promoting the use of fuel cells in vehicles, including Sections 731, 743, and 782; and *id.* at tit. VIII, which is focused specifically on hydrogen.

14 *See Hydrogen Program*, Dep't of Energy, www.hydrogen.energy.gov (last visited June 24, 2021).

Hydrogen Program, DOE "conducts research and development in hydrogen production, delivery, infrastructure, storage, fuel cells, and multiple end uses across transportation, industrial, and stationary power applications."[15]

The Hydrogen Program focuses on hydrogen production, hydrogen delivery, hydrogen storage, fuel cells, codes and standards, safety, applications and technology validation, and DOE's H2@Scale program.[16] DOE has used the H2@Scale program to award hundreds of millions of dollars in funding to numerous projects focused on research, development, and demonstration activities related to realizing the potential of a hydrogen economy at scale.[17] This work also involves DOE's National Laboratories,[18] which partner with the industry on demonstration projects[19] and publish technical reports focused on advancing the industry.[20]

Examples of DOE funding opportunities in 2021 (as of the writing of this chapter) include:

- HFTO's request for proposals seeking advanced research support to help realize the H2@Scale program vision and the National Renewable Energy Laboratories' Advanced Research on Integrated Energy Systems research goals;[21]

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15 *Id.*

16 *Id.*

17 *See H2@Scale*, Dep't of Energy, www.energy.gov/eere/fuelcells/h2scale (last visited June 24, 2021).

18 *Id.*

19 *See* Off. of Energy Efficiency & Renewable Energy, Dep't of Energy, H2@Scale: Enabling Affordable, Reliable, Clean, and Secure Energy Across Sectors (2020), https://www.energy.gov/eere/fuelcells/downloads/h2scale-crada-projects.

20 *See, e.g.,* Amgad Elgowainy, et al., Argonne Nat'l Lab'y, Assessment of Potential Future Demands for Hydrogen in the United States (2020) (available at https://greet.es.anl.gov/files/us_future_h2); Mark F. Ruth, et al., Nat'l Renewable Energy Lab'y, The Technical and Economic Potential of the H2@Scale Concept within the United States (2020) (available at https://www.nrel.gov/docs/fy21osti/77610.pdf); Elizabeth Connelly, Nat'l Renewable Energy Lab'y, Resource Assessment for Hydrogen Production (2020) (available at https://www.nrel.gov/docs/fy20osti/77198.pdf).

21 *See H2@Scale Laboratory CRADA Call*, Nat'l Renewable Energy Laboratories, https://www.nrel.gov/hydrogen/h2-at-scale-crada-call.html (last visited July 15, 2021).

- A joint initiative between HFTO and DOE's Vehicle Technologies Office that offers up to 100 million dollars over four years to pioneer electrified medium- and heavy-duty trucks and freight system concepts that achieve higher efficiency and lower emissions;[22] and
- An opportunity to collaborate with experts from DOE and the National Laboratories to develop new or modified materials through the application of high performance computing, modeling, simulation, and data analysis.[23]

DOE Secretary Jennifer Granholm already has taken a number of steps to support the development of a hydrogen economy at scale in the United States. This includes Secretary Granholm's April 23, 2021 announcement during President Biden's Leaders Summit on Climate committing DOE to work to reduce the price of hydrogen produced from renewable energy sources by 80 percent by 2030.[24] On June 7, 2021, Secretary Granholm announced the launch of DOE's Energy Earthshots Initiative, which is focused on "accelerat[ing] breakthroughs of more abundant, affordable, and reliable clean energy solutions within the decade."[25] The first Energy Earthshot is the Hydrogen Shot, which "establishes a framework and foundation for clean hydrogen deployment in the American Jobs Plan, which includes support for demonstration projects."[26] Further, echoing her earlier comments, Secretary

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22 *See Hydrogen and Fuel Cell Technologies Office Funding Opportunities*, Dep't of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-funding-opportunities (last visited July 15, 2021).

23 *Id.*

24 *See Remarks as Delivered by Secretary Granholm at President Biden's Leaders Summit on Climate*, Dep't of Energy (Apr. 23, 2021) (available at https://www.energy.gov/articles/remarks-delivered-secretary-granholm-president-bidens-leaders-summit-climate).

25 *Secretary Granholm Launches Hydrogen Energy Earthshot to Accelerate Breakthroughs Toward a Net-Zero Economy,* Dep't of Energy (June 7, 2021) (available at https://www.energy.gov/articles/secretary-granholm-launches-hydrogen-energy-earthshot-accelerate-breakthroughs-toward-net).

26 *Id.*

Granholm noted that the Hydrogen Shot also "seeks to reduce the cost of clean hydrogen by 80% to $1 per kilogram in one decade."[27]

As with the deployment of other emerging energy technologies at scale, government support and involvement will likely continue to be critical to realizing the potential of a hydrogen economy at scale in the United States.

§ 9.03. Production Pathways.

Among the benefits of hydrogen is that it can be produced from a number of energy resources that already are part of our energy mix. While hydrogen is the most abundant element in the universe, it rarely exists on Earth in its pure form. Instead, hydrogen frequently binds to other elements - such as oxygen to form water (H_2O), nitrogen to form ammonia (NH_3), and carbon to form methane (CH_4). As a result, in order to produce hydrogen on Earth, it has to be split from the element(s) to which it is bound. Consequently, the potential emissions from the hydrogen production process (also called the production pathway) depend on the elements remaining once the hydrogen has been separated out and the production pathway that is deployed.

The hydrogen industry has developed a color nomenclature to describe the various hydrogen production pathways. These colors are not literal, as hydrogen itself is colorless. Instead, the colors are used as a shorthand and can help provide a sense of both the inputs or feedstocks necessary for production, as well as a general sense of the resulting hydrogen's carbon intensity or associated GHG footprint.

The main colors that are most commonly used are:

- **Brown:** Hydrogen produced from coal gasification;
- **Grey:** Hydrogen produced from natural gas (methane), typcally via steam methane reformation, without the use of carbon capture and sequestration;

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27 *Id.*

- **Blue:** Hydrogen produced from natural gas (methane), typically via steam methane reformation, coupled with carbon capture and sequestration; and
- **Green:** Hydrogen produced via electrolysis from renewable or other zero-emissions power source.

In addition to these main colors, there is a rainbow of other colors to describe additional hydrogen production pathways. This includes, for example, yellow hydrogen, which some use to refer to hydrogen produced from solar energy.[28] Others use yellow to refer to hydrogen produced through electrolysis utilizing electricity pulled from the power grid, where the electricity received could have been produced from coal, natural gas, or renewable sources.[29] Pink commonly is used to refer to hydrogen produced using nuclear power, while white hydrogen typically refers to the rare, naturally occurring hydrogen found in geologic formations. Turquoise is used to describe methane pyrolysis, an emerging technology, which results in hydrogen and solid carbon.[30]

Currently, approximately 95 percent of the hydrogen produced globally is brown or grey.[31] However, much of the government support offered in the United States and globally is focused on increasing hydrogen production with a lower GHG footprint than grey or brown hydrogen. Some of these opportunities focus specifically on green hydrogen[32] or on carbon capture

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28 *See, e.g.*, *The Hydrogen Colour Spectrum*, National Grid, https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum (last visited July 12, 2021).

29 *See, e.g.*, *Hydrogen: Clearing up the Colours*, Enapter (Sep. 30, 2020), https://www.enapter.com/hydrogen-clearing-up-the-colours.

30 *See Interview Methane Pyrolysis*, BASF, https://www.basf.com/us/en/who-we-are/sustainability/we-produce-safely-and-efficiently/energy-and-climate-protection/carbon-management/interview-methane-pyrolysis.html (last visited July 12, 2021).

31 International Renewable Energy Agency, Green Hydrogen: A Guide to Policy Making at 36 (available at https://www.irena.org).

32 For example, the European Commission's recently released "Fit for 55" policy Package promotes the use of green hydrogen and extends the EU-wide certification system for renewable fuels to include hydrogen. For additional information on the Fit for 55 Package, *see European Commission Proposes to Adapt its Legislative Framework in Various Policy Areas to Make it "Fit for 55,"* K&L Gates LLP, https://www.klgates.com/

technology,[33] while others focus more generally on "clean" hydrogen, as discussed in greater detail below.[34]

It is important to note that while the color nomenclature creates a shorthand that can be useful, it also has its limitations and challenges and has received criticism in the industry.[35] For example, there is debate about whether hydrogen produced from renewable natural gas that utilizes carbon capture and sequestration technology should be dubbed blue, blue-green, teal, or another color. Further, as with yellow hydrogen, there is not always agreement among members of the industry on the production pathway that each color represents. Critically, there may be real world implications if government support focuses only on specific hydrogen colors. This is particularly the case for production pathways that either do not cleanly fit into a specific color or for which there is debate over the appropriate color designation.

The color nomenclature also has been seen as potentially balkanizing the industry at a time when many are highly focused on promoting the development of a hydrogen economy more broadly. While many involved in the development of a hydrogen economy agree that the industry eventually should focus mainly on green production pathways, critics argue that the current nomenclature oversimplifies the steps necessary to achieve that goal.[36] More specifically, some in the industry argue that an overemphasis on green

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European-Commission-Proposes-to-Adapt-its-Legislative-Framework-in-Various-Policy-Areas-to-Make-it-Fit-For-55-7-15-2021.

33 *See* Angela C. Jones & Molly F. Sherlock, Cong. Rsch. Serv., IF11455, The Tax Credit for Carbon Sequestration (Section 45Q (2021) (available at https://fas.org/sgp/crs/misc/IF11455.pdf).

34 *See, e.g.*, *Committee Witnesses Applaud Manchin-Led Energy Infrastructure Proposal*, S. Comm. on Energy & Nat. Res. (June 24, 2021), https://www.energy.senate.gov/2021/6/committee-witnesses-applaud-manchin-led-energy-infrastructure-proposal; Clean Energy for America Act, S. 1298, 117th Cong. (2021); Clean H2 Production Act, S. 1807, 117th Cong. (2021).

35 *See, e.g.,* Hydrogen Rising, *The Colors of Hydrogen: Simple or Oversimplified?*, K&L Gates LLP (Feb. 24, 2021) (available at https://www.klgates.com/The-Colors-of-Hydrogen-Simple-or-Oversimplified-2-24-2021).

36 *See* Mark Kirby, *Enough of the Green-Blue Debate!*, H2 View (Apr. 16, 2021), https://www.h2-view.com/story/enough-of-the-green-blue-debate/.

hydrogen at this point in time ignores the interim role that blue hydrogen could play in ultimately developing a zero-carbon hydrogen economy.[37] In short, the color nomenclature may overlook technology that serves as a critical stepping stone on the path toward significant global emissions reductions and a green hydrogen economy.

As noted above, several key pieces of proposed legislation use more general terminology, such as "clean" hydrogen. However, it is important to note that the definitions of qualifying "clean" hydrogen vary. Several examples are instructive:

- For example, U.S. Senator Tom Carper (D-DE)'s recently proposed Clean H_2 Production Act would make available a production tax credit and an investment tax credit for hydrogen produced via a production pathway that results in at least a 50 percent reduction in GHG emissions as compared to hydrogen produced from non-renewable natural gas using steam reformation.[38] The cleaner the production pathway deployed, the higher the credit available.
- On July 30, 2021, a bipartisan group of U.S. senators led by Senator Mike Crapo (R-ID), ranking member of the Senate Finance Committee, and committee member Sheldon Whitehouse (D-RI) proposed the Energy Sector Innovation Credit Act ("ESIC") of 2021 similarly provides a production tax credit for "clean" hydrogen. Under ESIC, the credit would apply to "clean" hydrogen produced via electrolysis or any other method. Hydrogen qualifies as "clean" if, based on a lifecycle analysis, the production method results in a GHG emissions rate that is not greater than 2,500 CO_2-e per kilogram.[39]
- Senator Joe Manchin (D-WV), chairman of the Senate Energy and Natural Resources Committee recently introduced sweeping energy

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37 *See* Dennis Van Puyvelde, *Shades of Hydrogen — What's in a Colour?*, Energy Networks: 2020 Energy Insider (Sep. 24, 2020), https://www.energynetworks.com.au/news/energy-insider/2020-energy-insider/shades-of-hydrogen-whats-in-a-colour/.

38 Clean H2 Production Act, S. 1807, 117th Cong. (2021).

39 Energy Sector Innovation Credit Act of 2021, S. 2475, 117th Cong. (2021).

> legislation, including an entire title focused on the development and deployment of hydrogen, which the legislation expressly states applies to "the production of clean hydrogen from diverse energy sources, including — (A) fossil fuels with carbon capture, utilization, and sequestration; (B) hydrogen-carrier fuels (including ethanol and methanol); (C) renewable energy resources, including biomass; (D) nuclear energy; and (E) any other methods the Secretary [of Energy] determines to be appropriate."[40] While Senator Manchin's discussion draft would have left it to the Secretary of Energy to develop a GHG emissions standard to help define what qualifies as clean hydrogen, through the committee amendment process Senator Bill Cassidy (R-LA) amended the proposed legislation to define the term 'clean hydrogen' to mean "hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced."[41]

While broad definitions may allow innovative production pathways to displace incumbent technology, industry advocates and lawmakers also will need to be mindful of the potential for overly broad definitions to create ambiguity. Where there is a lack of clarity, questions and disputes may arise as bills move through the legislative process and in implementation. Regardless, measures that utilize a more general approach are being seen as more likely to help support development of a hydrogen economy at scale in the United States.[42]

§ 9.04. Hydrogen Use Opportunities.

The list of possible uses for hydrogen seems ever expanding, particularly in the transportation and logistics sector. While battery electric vehicles

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40 Energy Infrastructure Act, 117th Cong. (2021) [Discussion Draft].

41 Energy Infrastructure Act, Amendment 123, as modified, (July 14, 2021).

42 *See Air Liquide Welcomes U.S. Senator Carper of Delaware to its Innovation Campus*, Air Liquide (June 4, 2021), https://industry.airliquide.us/air-liquide-welcomes-us-senator-carper-delaware-its-innovation-campus. Commending the Clean Hydrogen Production Act, Mike Graff, chairman and CEO of American Air Liquide Holdings, Inc., stated that Senator Carper's bill would "help stimulate the production and use of low carbon hydrogen across all sectors, including transportation, industry and energy storage." *Id.*

are the incumbent technology for passenger vehicles, hydrogen offers the advantage of significantly improved refueling times — nearly identical to gasoline or diesel — and reduced fueling system weight, making more payload available for cargo. Hydrogen applications are being explored in the heavy- to medium-duty vehicle sector, rail, maritime, aviation, aerospace, passenger vehicles, forklifts, and in airports. New partnerships, demonstration projects, and deployment efforts are announced nearly every day. Below are a few examples of recent efforts (as of the writing of this chapter), but we anticipate that many more likely will be announced in the near future.

- **Zero-Avia.** Zero-Avia is a California company pioneering the world's first fleet of hydrogen-electric aircraft. Following the company's successful development of a six-seat hydrogen aircraft, the company seeks to add two 19-seat hydrogen aircraft to its fleet by 2024, and eventually expand to 50-seat aircraft.[43]
- **Puma.** Puma, a German company known worldwide for its sports and athletic apparel brands, recently purchased six hydrogen-powered vehicles from Hyundai Nexo.[44] The company seeks to cut its CO_2 emissions by 35 percent by 2030, and views alternative fuels as a key component of its strategy.
- **Water Taxis/Ferries.** California company Zero Emissions Industries (ZEI), formerly known as Golden Gate Zero Emission Marine, produced the first-ever hydrogen-powered commercial vessel, the *Sea Change*. The company expects to conduct sea trials later in 2021, and begin transporting passengers shortly thereafter. ZEI has received a number of grants and funding opportunities to develop similar hydrogen-powered vessels elsewhere in the next few years.[45]

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43 *See* Chris Price, *ZeroAvia to Develop Hydrogen-Electric Aircraft*, Tech Dig. (June 30, 2021), https://www.techdigest.tv/2021/06/zeroavia-to-develop-hydrogen-electric-aircraft.html.

44 *See* Molly Burgess, *PUMA Expands Hydrogen Vehicle Fleet*, H2 View (Oct. 22, 2020), https://www.h2-view.com/story/puma-expands-hydrogen-vehicle-fleet/.

45 *See* Nick Blenkey, *ZEI's Hydrogen-Powered Craft Project Gets $2 Million Grant*, Marine Log (Apr. 28, 2021), https://www.marinelog.com/technology/zeis-new-hydrogen-powered-craft-project-gets-2-million-california-grant/.

- **Paris Airport.** Choose Paris Region intends to transform the city's airports into an "H2 Hub" for hydrogen-powered commercial aircraft. The organization expects to welcome the first commercial hydrogen-powered aircraft to Paris by 2035, and recently awarded a series of contracts to begin supporting that initiative. For example, one contractor will transport liquid hydrogen to a new airport storage facility operated by a different contractor.
- **Fortescue and Christmas Creek Mine.** Australian iron ore company Fortescue recently added ten hydrogen-powered coaches to its transportation fleet as part of the company's goal of eliminating all operational emissions by 2030.[46]

In addition, there is significant interest in using hydrogen fuel cells for forklifts[47] and in applications where access to consistent, reliable electricity is critical, such as data centers.

There are also several applications contemplated beyond fuel cells. This includes using hydrogen to store renewable electricity, which would assist in evening out intermittency issues that renewable energy sources typically face. This storage would be achieved by diverting electricity from a renewable source (*e.g.*, wind or solar) to an electrolyzer instead of selling the power into the grid. The electrolyzer would use the renewable electricity to produce hydrogen, which could be stored — essentially storing the renewable electrons as molecules. When demand or economics warrant, the hydrogen would then be used to power a fuel cell to generate electricity.

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46 *See Fortescue Advances Hydrogen Technology at Christmas Creek*, Fortescue Metals Grp. Ltd. (Aug. 17, 2020), https://www.fmgl.com.au/in-the-news/media-releases/2020/08/17/fortescue-advances-hydrogen-technology-at-christmas-creek.

47 As of November 2018, DOE estimated that there were over 22,000 hydrogen forklifts in the United States. *See Fact of the Month November 2018: There Are Now More Than 20,000 Hydrogen Fuel Cell Forklifts in Use Across the United States*, Dep't of Energy, https://www.energy.gov/eere/fuelcells/fact-month-november-2018-there-are-now-more-20000-hydrogen-fuel-cell-forklifts-use (last visited July 12, 2021).

Steel manufacturers also are exploring using hydrogen to replace coke in the steel manufacturing process.[48] Other potential applications include using hydrogen to fuel power generation[49] and in home heating applications.[50]

§ 9.05. Potential Challenges.

While hydrogen presents significant opportunities, there are a number of challenges that the hydrogen industry will have to overcome to reach scale both in the United States and globally.

One challenge is the development of a supply chain that can accommodate volumes at scale. Presently, the majority of hydrogen produced in the United States either is produced onsite or transported to customers by truck. Use of pipelines to transport hydrogen could allow for an economy of scale that would reduce transportation costs and help increase demand. This is particularly the case if the United States' existing natural gas pipeline system, which includes nearly three million miles of interstate and intrastate pipelines,[51] can be used to transport hydrogen.

However, there are both physical and regulatory challenges to deploying the existing U.S. natural gas pipeline infrastructure. From a physical

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48 *See* Ken Silverstein, *We Could Be Making Steel From Green Hydrogen, Using Less Coal*, Forbes (Jan. 25, 2021, 8:50 AM), https://www.forbes.com/sites/kensilverstein/2021/01/25/we-could-be-making-steel-from-green-hydrogen-using-less-coal/?sh=795cba4e3e5c. Australia's Andrew Forrest, the chairman of Fortescue Metals, challenged the nation to transition from creating steel with iron oxide and coal to creating "green steel" with hydrogen and other renewable energies. *Id.*

49 *See* Darrell Proctor, *Siemens Studies Hydrogen Production, Storage at Utah Plant*, Power Mag. (Mar. 1, 2021), https://www.powermag.com/siemens-studies-hydrogen-production-storage-at-utah-plant/.

50 *See* Stuart Clark, *Is Hydrogen the Solution to Net-Zero Home Heating?*, The Guardian (Mar. 21, 2020, 1:00 P.M.), https://www.theguardian.com/science/2020/mar/21/is-hydrogen-the-solution-to-net-zero-home-heating. After the United Kingdom agreed in 2019 to reduce carbon emissions to "effectively nothing" by 2050, experts targeted home heating as one of the nation's biggest hurdles to achieving their reduction goal. *Id.* Worcester Bosch, a U.K. boiler brand, introduced a prototype of a hydrogen-ready boiler in February 2020. *See id.*

51 *Natural Gas Explained: Natural Gas Pipelines*, Energy Information Admin., https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php (last visited July 22, 2021).

perspective, hydrogen can cause steel embrittlement and, given its small size, there also may be product loss associated with transporting hydrogen using existing pipelines. To help gauge feasible thresholds and identify issues, a number of utility companies in the United States and around the world are looking to test the impacts of blending various levels of hydrogen into the natural gas stream.[52]

Regulatory issues also arise with the use of existing natural gas pipelines, particularly if hydrogen is transported as part of the natural gas stream.[53] The Federal Energy Regulatory Commission ("FERC") regulates the siting, construction, and operation of interstate natural gas pipelines, as well as the rates and terms and conditions of service under the Natural Gas Act ("NGA").[54] "Natural gas" is defined in the NGA as "natural gas unmixed, or any mixture of natural and artificial gas."[55] Presently, it is unclear whether FERC would consider hydrogen to be an "artificial gas" under the NGA definition. If FERC were to conclude that hydrogen is an "artificial gas" and, therefore, that hydrogen mixed with natural gas falls under its jurisdiction, several key threshold issues arise, including the development of practices for nominating hydrogen to flow on a particular natural gas pipeline, the establishment of specifications for gas composition, and the allocation of costs associated with transporting hydrogen.[56]

While the physical challenges noted above may be eased by building new, dedicated hydrogen pipelines,[57] interstate hydrogen pipelines still may face significant regulatory issues. For example, unlike interstate natural gas

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52 *See* Stephanie Kelly and Scott Disavino, *U.S. Natgas Companies Put Hydrogen to the Test,* Reuters (July 1, 2021), https://www.reuters.com/business/sustainable-business/us-natgas-companies-put-hydrogen-test-2021-07-01/.

53 Note, the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") existing regulations at 49 C.F.R. Part 192 includes pipelines that transport flammable gas, like hydrogen, and PHMSA has regulated hydrogen under Part 192 since 1970. *Hydrogen*, Pipeline and Hazardous Materials Safety Admin., https://primis.phmsa.dot.gov/comm/Hydrogen.htm (last visited July 22, 2021).

54 15 U.S.C. §717, *et seq.*

55 *Id.* at §717a(6).

56 For a more in-depth discussion of these issues, *see* The H_2 Handbook: United States, K&L Gates LLP at 51-60 (available at https://www.klgates.com/The-Hydrogen-Handbook).

57 DOE estimates that there are 1,600 miles of hydrogen pipeline operating in the United States. *Hydrogen Pipelines*, Dep't of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines (last visited July 23, 2021).

pipelines, issuance of certificates for siting, construction, and operation of interstate hydrogen pipelines does not reside with a single federal agency. Consequently, interstate hydrogen pipeline developers currently would need to obtain certificates or authorization to site, construct, and operate their projects from each state that the pipeline would pass through and the specific requirements vary by state. Furthermore, while the NGA grants eminent domain authority to interstate natural gas pipeline certificate holders, interstate hydrogen pipeline developers would be subject to the various eminent domain rules of the states through which their projects cross.[58]

Other issues that the industry will need to address include the use and availability of water under various water rights regimes;[59] the potential that sellers will need to certify the method used to produce hydrogen, particularly when product is comingled in tank; the development of commodity pricing benchmarks on a local, national, and global level; and, in the nascent stages, the first mover disadvantage and appropriate cover for an illiquid market.

§ 9.06. Conclusion.

While the precise contours of a hydrogen economy at scale are still being developed, the level of support from governments around the world, as well as the private sector, suggest a bright future for hydrogen. Given the ability to produce hydrogen from a range of energy sources that already are part of our energy economy, its seemingly innumerable potential uses, and its zero emissions combustion profile, this small but mighty molecule could play a key role in the energy sector in the near future and for years to come.

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58 For a more in-depth discussion of these issues , *see* The H_2 Handbook: United States, K&L Gates LLP at 58-60 (available at https://www.klgates.com/The-Hydrogen-Handbook).

59 *See* Hydrogen Rising, *Wading In: Water Resource Issues in the Development of the Hydrogen Economy,* K&L Gates LLP (Apr. 21, 2021), https://www.klgates.com/Wading-In-Water-Resource-Issues-in-the-Development-of-the-Hydrogen-Economy-4-21-2021.

Chapter 10

Shining a Light on Solar Energy Projects: Impact of Mineral Issues on Solar Leasing

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1 David R. Dehoney and Lauren W. Varnado are principals in McKool Smith P.C.'s New York and Houston offices, respectively. The authors thank Veronica F. Manning and Kristin L. Leveille at McKool Smith P.C. for their contributions to this chapter.

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§ 10.01. Overview.

This chapter serves as an introduction to solar energy development and lease considerations, highlighting the growing commitment to renewable energy and potential areas of conflict involving solar energy producers and mineral and surface rights holders. This chapter examines areas ripe for disputes involving solar energy projects in light of prevailing renewable energy market conditions and contracting practices, including the impact of mineral issues on solar leases and application of traditional oil and gas lease doctrines such as the accommodation doctrine.

The case law in this area is in its developing stages. A recent Texas appellate court opinion in the case *Lyle v. Midway Solar*, 618 S.W.3d 857 (Tex. App-El Paso 2020), provides a glimpse into the future — illustrating the complex interplay among mineral owners, surface owners, and solar lessees. It also forecasts some of the challenges courts will face when asked to resolve solar lease disputes in the absence of an established body of law addressing solar-specific concerns. Using *Lyle* as an example, the court concluded that the accommodation doctrine would likely apply between solar lessees and mineral owners, but declined to apply the doctrine under the circumstances since it was undisputed the mineral owner had taken no steps to develop the minerals. Thus, *Lyle* leaves open the question of how specifically courts will apply the multi-prong test.

§ 10.02. Rapid Growth in Solar Energy Development in the United States.

In recent years, the United States has entered an era of rapid growth in solar energy leasing and development across the country.[2] Unlike other natural resources such as coal, oil, and gas, solar energy can be collected from almost

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[2] *See, e.g.*, Alex McClintic and Brent Stahl, *Mineral Issues' Impact on Solar Energy Projects*, Section Report of the Oil, Gas and Energy Resources Law Section of the State Bar of Texas (Summer 2020).

any location and any state.[3] The location of solar projects is dictated less by the strength of the resources in the area and more by the distance of the property to existing transmission lines, water access, and roadways. In this way, solar differs from mineral development projects and even wind projects, which are placed according to known and predictable wind flow patterns.[4] In 2020 alone, utility-scale solar generation increased 26% in the U.S.[5]

With these developments, utilities, municipalities, and corporations have come under increased pressure to commit to purchase from renewable sources. Since 2018, fifteen states have enacted so-called clean energy commitments, initiatives, and legislation aimed at increasing alternative sources of energy and fuel.[6] This focus on renewable energy and investment into large-scale solar production facilities is a sure sign that the industry's growth will continue in the coming years and solar power will begin to make up an increasingly larger portion of our energy resources. As solar projects proliferate, so does the potential for disputes among the various interest-holders. It is important to be aware of and, where possible, mitigate the disruption these disputes may cause between surface and mineral right interest owners.

§ 10.03. Potential Issues Raised by Growing Solar Energy Development.

Historically, the potential for lease disputes in the energy industry has arisen in the oil and gas context, primarily in the relationship between surface

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3 *See* F. Parks Brown, *Solar Lease Negotiations from the Landowner's Perspective*, 49 Tex. J. Bus. L. 1 (2020).

4 *Id*. at 1.

5 *Renewables became the second-most prevalent U.S. electricity source in 2020*, U.S. Energy Information Administration (July 28, 2021), www.eia.gov/todayinenergy/detail.php?id=48896.

6 *See State Renewable Portfolio Standards and Goals*, Nat'l Conference of St. Leg. (Last accessed on Sept. 1, 2021), www.ncsl.org/research/energy/renewable-portfolio-standards.aspx; *see also* Don Hopey, *Nearly Half of Pennsylvania Government Electricity to Come From Solar Power by 2023*, Pittsburgh Post-Gazette (Mar. 22, 2021), www.post-gazette.com/business/powersource/2021/03/22/Pennsylvania-government-solar-powered-project-2023-energy-electricity-supply-arrays/stories/202103220063; Matthew Bandyk, *Virginia approves 100% clean energy legislation, pushing state toward 2.4 GW storage, RRGI,* Utility Dive (Feb. 14, 2020), www.utilitydive.com/news/virginia-clean-energy-legislation-pushes-state-toward-storage-rggi/572349/.

owner and mineral owner or developer. The growth of the solar energy industry adds a new party into the relationship – the solar developer. Solar developers seeking to build solar projects enter into long-term surface lease agreements with landowners. The addition of the solar developer, as surface lessee, brings new opportunities for disagreements and disputes between surface and mineral interest owners.

As in the oil and gas context, the conflict potential of a solar project is greatest in situations where the mineral estate is severed, or owned separately, from the surface estate, or where there is an existing lease of the minerals. In such situations, disputes may arise concerning access or use of the surface, use of water or other resources on the property, repair or remediation of the surface, and other issues.[7]

Solar lessees are, by necessity, granted expansive surface rights over the development location. Solar projects typically encompass the entire surface area of a project site, which could impair a mineral developer's ability to explore and drill for oil and gas that might lie beneath the surface. However, the prevalence and availability of horizontal drilling throughout the U.S. may allow solar lessees to continue existing use, even if such use covers a significant portion of the surface estate.

This begs the question: when the mineral estate and surface estates are separately owned, what degree of accommodation do mineral owners who seek access and use of the surface to develop minerals provide to solar lessees who are operating facilities on the surface?

Litigants in the solar energy space, unlike those involved in oil and gas disputes, do not have the benefit of hindsight provided by developed case law and decades of previous lease transactions. Still, courts are likely to draw from developed oil and gas case law involving competing surface uses and lease negotiations and solar litigants can glean insight from the courts' resolution of disputes in that industry.

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7 Meredith A. Wegener, *Balancing Rights in a New Energy Era: Will the Mineral Estate's Dominance Continue?*, 57 Hous. L. Rev. 1037, 1043 (2020). (hereinafter cited as *Wegener*).

§ 10.04. Overview of Mineral Estate vs. Surface Estate.

[1] – Dominance of the Mineral Estate.

It is well-established that in locations where the minerals can be severed from the surface, the mineral estate is considered the dominant estate.[8] This is so because drilling and developing oil and gas resources necessitates access to the earth's surface, rendering the mineral estate essentially unusable without surface access. The dominance of the mineral estate means that the mineral owner has the right to access and use as much of the surface and subsurface as reasonably necessary to make use of the mineral estate.[9]

The surface estate is subservient, meaning has limited protections, absent a contractual arrangement. The common law "accommodation doctrine" offers some protection, under which a mineral owner may be required to make reasonable accommodations to his proposed use of the surface to avoid disrupting the surface owner's existing use of the surface.[10] However, in situations where the mineral owner can show there is no reasonable alternative available, courts allow mineral owners to proceed, over the surface owner's objections, even if the method used to develop the minerals "precludes or substantially impairs an existing use of the servient surface estate."[11]

[2] – The Accommodation Doctrine.

All states in which the surface and mineral estates are severable have adopted a form of the accommodation doctrine, sometimes referred to as the doctrine of reasonable use.[12] The accommodation doctrine is a judicially created

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8 Essentially all states to have considered the issue of split estates have adopted the general dominant mineral estate rule. *See* n. 11; *Wegener* at 1040.

9 *See Wegener* at 1040; *see, e.g.*, Coyote Lake Ranch, LLC v. City of Lubbock, 498 S.W.3d 53, 61 (Tex. 2016); Getty Oil v. Jones, 470 S.W.2d 618, 621 (Tex. 1971). (hereinafter cited as *Getty Oil*).

10 *See, e.g.*, Lyle v. Midway Solar, 618 S.W.3d 857, 868-69 (Tex. App—El Paso 2020). (hereinafter cited as *Lyle*).

11 Merriman v. XTO Energy, Inc., 407 S.W.3d 244, 249 (Tex. 2013).

12 *See, e.g.*, *Getty Oil*, 470 S.W.2d at 618 (adopting Texas accommodation doctrine); Lindsey v. Wilson, 332 S.W.2d 641 (Ky. 1960) (lessee has right to use as much or surface as may be "necessary and reasonably convenient" in the exercise of his rights); Union Prod. Co. v. Pittman, 146 So.2d 553 (Miss. 1962) (when reasonably necessary, mineral owner may cause "inconvenience" to surface owner's use of surface); Norton Farms, Inc. v. Anadarko Petroleum

doctrine that developed in an effort to balance the rights between mineral and surface estate owners.[13] In general, the doctrine applies only when an underlying deed or lease governing the parties' relationship does not address surface use.[14]

Under this common law doctrine, a mineral interest owner may be required to alter or revise its activities on the surface of the property to accommodate the surface owner's existing use of the surface.[15]

More specifically, where there is an existing use by the surface party that would be substantially impaired or precluded by the mineral party's activities on the surface, and where there is an industry-established alternative practice reasonably available to the mineral party, the mineral party may be required to use the alternative.[16] The surface party bears the burden of proving both the impairment or preclusion of its surface use, and the availability of a reasonable alternative to the mineral party.[17] If the surface party fails to carry its burden, the accommodation doctrine will not apply.

[3] — State Legislation on Surface Owner Rights and Protections.

Because the surface/mineral owner relationship, and the corresponding rights of each party, have largely been developed by the courts through the common law, many states have passed legislation seeking to clarify the rights between mineral and surface owners.[18] These laws do not generally attempt to alter the common law doctrine, but they may provide surface owners with clearer rights and remedies in the event of a dispute regarding surface use.[19]

Corp., 91 P.3d 1239 (Kan. Ct. App. 2004) (lessee has implied right to make reasonable use of surface); Burlington Res. Oil & Gas Co., LP v. Lang and Sons Inc., 259 P.3d 766 (Mont. 2011) (mineral estate owner is permitted to reasonably use surface estate).

13 *Lyle*, 618 S.W.3d at 868-69; *see also Getty Oil*, 470 S.W.2d at 623 (adopting the accommodation doctrine in an effort to balance rights between mineral and surface estates).

14 *Id.*

15 *Getty Oil*, 470 S.W.2d at 622.

16 *See id.*; *see e.g.,* Tarrant County Water Control and Imp. Dist. No. One v. Haupt, Inc., 854 S.W.2d 909 (Tex. 1993).

17 *Lyle*, 618 S.W.3d at 868-69.

18 Katherine Toan, *Split Estates*, at 5-7 (available at https://www.oilandgasbmps.org/docs/GEN324_split%20estates.pdf).

19 *Id.*

§ 10.05 *Lyle v. Midway Solar*, 618 S.W 3d 857 (Tex. App.—El Paso 2020).

The recent Texas appellate decision in *Lyle v. Midway Solar*, 618 S.W.3d (Tex. App—El Paso 2020) illustrates the types of disputes that can arise between mineral interest owners and solar lessees, including whether and how the accommodation doctrine applies.

[1] – Facts.

In *Lyle*, Kenneth R. Lyle and Linda L. Morrison (the "Lyles"), the owners of an undeveloped mineral estate located on a 315-acre tract of land ("Section 14"), brought suit against Midway Solar, LLC, the solar lessee and owners of a large-scale solar facility situated on Section 14.[20] A the time of the lawsuit, Midway had covered approximately 215 acres, or 70% of the surface of the tract of land, with solar panels.[21]

[a] — Mineral and Surface Estates.

The Lyles had obtained their mineral ownership in Section 14 from a 1948 deed, in which the owners of the tract transferred ownership of the surface to an unrelated third party, thereby severing the mineral and surface estates.[22] At the time of the lawsuit, Gary D. Drgac owned 100% of the surface rights in Section 14 but had no interest in the mineral estate.[23] Since obtaining their mineral interests, the Lyles had never leased their interests an oil or gas operator nor had any plans at the time the lawsuit was filed to lease or otherwise develop the minerals.[24]

[b] — Solar Lease.

In 2015, Drgac entered into a solar lease with Midway, allowing it to build a solar energy facility on portions of the land.[25] Under the terms of the solar lease, Midway had the right "to free and unobstructed use and development of

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20 *Lyle*, 618 S.W.3d. at 862.
21 *Id.*
22 *Id.*
23 *Id.* at 863.
24 *Id.*
25 *Id.*

solar energy resources" for up to fifty-five years.[26] The solar lease also granted Midway the right to place solar panels, transmission lines, electrical lines and cable lines on the surface of Section 14, subject to Drgac's consent.[27] In the solar leases, Midway acknowledged the severance of the minerals and that the Lyle's mineral ownership rights constituted an "encumbrance" on the property.[28] Midway also acknowledged that Drgac had no "right to control" the Lyle's activities.[29] Finally, Drgac agreed to cooperate with Midway "in obtaining surface waivers . . . from each owner of a mineral interest."[30]

In an effort to leave open part of the surface for future drilling, the solar leases were amended to identify "Designated Drill Site Tracts"—80-acre portions of Section 14 for which a present or future operator could explore for oil and gas.[31] However, the Lyles had no input into the location of these drilling sites.[32]

In 2016, Midway obtained waiver agreements from twenty individuals who owned mineral interests on adjoining property to Section 14, which purported to relinquish all or a portion of the individuals' rights to use the surface of the leased premises for mineral exploration.[33] The Lyles did not sign the waivers.[34]

[2] — Procedural Posture.

The Lyles filed suit in 2018 against Midway, Drgac, and the twenty individuals who signed the surface waivers, arguing that (1) the surface waivers created a cloud on their title, (2) Midway and Drgac had breached the terms of the deed because the Lyles were denied "reasonable access" to the minerals by covering 70% of the surface with solar panels, and (3) these actions constituted a trespass on the Lyle's mineral estate.[35]

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26 *Id.*
27 *Id.*
28 *Id.*
29 *Id.*
30 *Id.*
31 *Id.*
32 *Id.*
33 *Id.* at 864.
34 *Id.*
35 *Id.* at 864-65.

The trial court determined on motions for summary judgment Midway had filed Disclaimers of Interest, which removed any purported cloud on title.[36] Midway and Drgac then filed motions for summary judgment, arguing that the accommodation doctrine applied.[37] The trial court granted Midway's motions and entered a final take-nothing judgment against the Lyles.[38]

[3] — Parties' Arguments on Appeal.

On appeal, Midway and Drgac argued that the accommodation doctrine applied, but that under that doctrine, Midway owed no duty to accommodate the Lyles because they had failed to develop the mineral estate and had no current plans to do so.[39] Midway argued that therefore, its use of the surface for purposes of operating the solar facility was "reasonable as a matter of law."[40] Thus, the Lyles had no basis for either their trespass or breach of contract claims.[41]

In response, the Lyles argued that although they had not developed the minerals, they were injured by the construction of the solar facility that covered the majority of Section 14, which they claimed caused a diminution in value to the mineral estate.[42] The Lyles submitted expert affidavits claiming that the solar facility "severely" affected the ability of any operator to develop the minerals because horizontal drilling would be required and the remaining space on the surface was too narrow.[43]

[4] — The Accommodation Doctrine.

In deciding the issues on appeal, the court recognized that whether the accommodation doctrine applied constituted the key question.[44] The court explained the accommodation doctrine holds that the "mineral and surface

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36 *Id.*
37 *Id.* at 865.
38 *Id.* at 866.
39 *Id.* at 867.
40 *Id.*
41 *Id.*
42 *Id.*
43 *Id.*
44 *Id.* at 868.

estates must exercise their respective rights with due regard for the other's.'[45] The court noted that under the accommodation doctrine, a surface owner carries the burden to show that "(1) the mineral owner's use of the surface completely precludes or substantially impairs the surface owner's existing use, and (2) there is no reasonable alternative method available to the surface owner by which the existing use can be continued.'[46] The surface owner must also prove that there are "alternative reasonable, customary, and industry-accepted methods available to the [mineral owner] which will allow recovery of the minerals and also allow the surface owner to continue the existing use.'[47] If the surface owner is able to show a reasonable alternative, the accommodation doctrine may require the mineral interest owner to adopt that method.[48]

The court also emphasized that Texas public policy "strongly" favors freedom of contract such that the accommodation doctrine will not apply where a parties' deed or contract sets forth the parties' rights.[49]

[5] — The Court's Decision.

[a] — The 1948 Deed Did Not Preclude Application of the Accommodation Doctrine.

In determining whether the accommodation doctrine applied, the court first looked to the terms of the 1948 deed.[50] The court rejected the Lyle's argument that the accommodation doctrine did not apply because the deed granted the mineral owners the "usual, necessary or convenient" use and enjoyment of the oil, gas, and mineral estate.[51] The Lyles contended that the use of the word "usual" clearly and objectively defined its rights to use vertical drilling, which would have been the "usual" method of drilling at the time the deed was signed.[52]

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45 *Id.* (citing Coyote Lake Ranch, LLC v. City of Lubbock, 498 S.W.3d 53, 60 (Tex. 2016)).
46 *Id.*
47 *Id.*
48 *Id.*
49 *Id.*
50 *Id.*
51 *Id.* at 870.
52 *Id.*

The court rejected this argument, explaining that the term "usual" was not used in the specific context of drilling methods and was otherwise ambiguous.[53]

The court also rejected the Lyles' argument that the "elimination of liability" provision in the deed negated any basis for the accommodation doctrine.[54] The court thus concluded that the 1948 deed did not preclude the application of the accommodation doctrine.[55]

[b] — The Accommodation Doctrine Requires Actual Plans to Develop the Mineral Estate to Pursue a Legal Remedy.

Despite concluding that the language in the 1948 deed did not preclude the application of the accommodation doctrine, the court held that the accommodation doctrine will not apply unless and until the Lyles sought to develop their minerals.[56] It was undisputed that the Lyles had taken no action to develop or lease their minerals.[57]

Specifically, the court explained that to hold otherwise would lead to a premature application of the doctrine:

> Midway has the right to use the surface. The Lyles also have the right to use the surface, but only as an adjunct to their mineral estate. If the Lyles exercise their right as part of developing the minerals, Midway must yield to the degree mandated by the application of the accommodation doctrine. ***But if the Lyles are not exercising their right, there is nothing to be accommodated. Stated otherwise, until the Lyles seek to develop their minerals, Midway owes no duty to the Lyles respecting the surface usage***.[58]
>
> (emphasis added)

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53 *Id.*
54 *Id.*
55 *Id.*
56 *Id.*
57 *Id.*
58 *Id.* (emphasis added).

The court further emphasized the problem it saw with awarding trespass damages for a mineral estate that may never be developed.[59] As such, the Court concluded that the trial court should have dismissed the Lyle's trespass and breach of contract claims as premature.[60]

[6] — Takeaway from *Lyle v. Midway Solar*.

The court's decision in *Lyle v. Midway Solar* makes clear that courts are willing to apply the accommodation doctrine in disputes between mineral owners and solar lessees where the mineral owner has taken some steps toward developing the mineral estate. Otherwise, any dispute between an owner of undeveloped minerals and a surface lessee and whether the accommodation doctrine applies is premature.

The primary unanswered questions arising out of *Lyle* include to what degree solar lessees will be required to disrupt their existing solar operations for the benefit of mineral owners in the event no industry-established alternative practice is reasonably available to the mineral party. Will solar lessees be required to remove or relocate equipment to allow access? To the extent mineral owners must accommodate solar lessees' surface use, what will the courts find constitutes reasonable alternative methods for recovery of the minerals? The court in *Lyle* entertained arguments about whether horizontal drilling is an available drilling alternative.[61]

This case also illustrates the importance of solar lessees drafting and obtaining clear and precise waiver agreements to prevent disputes over surface use. In the event a surface lessee is unable to obtain waivers preventing the development of any underlying minerals while the solar lease is operative, this may deter solar development.

§ 10.06. Practical Considerations and Outlook.

Although the *Lyle* court declined to address the issue, it is likely that when the issue is presented properly before the courts, they will find the

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59 *Id*.

60 *Id*. The court did hold, however, that the Lyles could pursue their some of their trespass to quiet title claim based on the waiver agreements.

61 *Id*. at 868-867.

accommodation doctrine applies to a land use dispute between solar lessee and mineral owner, so long as the parties' relationship has not been delineated by contract or other arrangement. This result is all but necessitated by the pervasiveness of the doctrine of the dominant mineral estate in United States common law. Unless a mineral owner has access to the surface, he cannot develop the minerals.

The more uncertain issue is the degree to which a solar lessee will be required to disrupt its existing solar installment for the benefit of a mineral owner who seeks to explore or develop their mineral interest. If past applications of the accommodation doctrine in the oil and gas context carry over into the solar energy space, it is likely that unless there is a reasonable alternative to develop the minerals, a solar lessee may be required to undergo substantial disruption to its operation to facilitate the mineral owner's activities, including, for example, having to remove or relocate solar panels, transmission lines, and other permanent installations on the property.

The practical effect of this possibility means it is unlikely a solar developer will enter into a solar lease to proceed with a solar project unless it can either obtain ownership or control over the mineral estate, or an agreement from the mineral owner waiving surface rights or agreeing to other accommodations, such as exclusively pursuing mineral development in a manner that will not the disturb the surface, such as horizontal drilling or pooling.[62]

If unable to obtain agreement from the mineral owner, a solar developer determined to proceed may attempt to minimize potential disruption by leaving designated tracts of land open for the benefit of the mineral owner to explore or develop in the future. As the *Lyle* case demonstrates, however, the lessee's unilateral designation of mineral development sites may not be sufficient to prevent litigation, particularly when the site locations are designated based on convenience to the lessee, rather than on the identification of locations most suitable for drilling.

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62 *See* F. Parks Brown, *Solar Lease Negotiations from the Landowner's Perspective*, 49 Tex. J. Bus. L. 1, 18 (2020).

Chapter 11

State Solar Regulation in Appalachia[1]

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1 This chapter was presented at the Energy & Mineral Law Foundation's Special Institute on Solar Power, January 27, 2021. Because of the evolving nature of solar regulation, some aspects of the scholarship have been updated by the authors prior to publication.

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§ 11.01. Kentucky.

[1] — Introduction.

Kentucky is a traditional energy producer, though Kentucky produces far more coal and natural gas than renewable energy at present. In 2020, the net electricity generation in the Commonwealth was as follows:

- 69% Coal-Fired
- 23% Natural Gas-Fired
- 7.0% Renewables[2]

In 2020, almost all Kentucky renewable generation was attributable to hydroelectric power, very little to solar, and there were no commercial wind

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2 *Kentucky State Profile and Energy Estimates*, U.S. Energy Information Administration (July 15, 2021), https://www.eia.gov/state/analysis.php?sid=KY.

generation facilities.[3] However, solar is quickly emerging as the future of Kentucky's renewable energy mix. The solar energy industry in Kentucky is nascent, but growing. One evaluation has put Kentucky's potential for wind, rooftop solar, and utility-scale solar at greater than 2.4 million gigawatt hours.[4] That said, when we talk about the future of renewable energy generation in Kentucky, we are talking about solar. The change in the scale of solar generation projects is astounding. At the end of 2020, the largest solar generation facility in Kentucky was 10MW.[5] There are now multiple projects in development which will generate well over 100 MW.[6]

Currently, because Kentucky's solar industry has been somewhat dormant, state-level regulation has been light. There is currently no Renewable Portfolio Standard or Renewable Portfolio Goal in Kentucky. Incentives at the state level are also limited. Kentucky's largest incentives had been the Incentives for Energy Independence Act (IEIA).[7] Unfortunately, the IEIA was phased out and then rewritten to provide incentives for cryptocurrency mining and no longer can be relied upon to aid renewable energy development.[8] However, Kentucky has amended KRS 103.200, which deals with Industrial Revenue Bonds to include "solar generated electricity."[9] This allows qualifying facilities generating solar energy to apply for Industrial Revenue Bonds issued by the state and local government in Kentucky.[10]

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3 *Id*.

4 Grant Smith, *After the Pandemic, Kentucky can Rebuild the Economy and Create Jobs by Investing in Clean Energy*, EWG (April 24, 2020), ewg.org/news-insights/news/after-pandemic-kentucky-can-rebuild-economy-and-create-jobs-investing-clean#:~:text=Kentucky's%20technical%20potential%20for%20wind,generated%20in%20state%20in%202019%20.

5 Ryan Van Velzer, *LG&E Proposes Largest Solar Field in Kentucky*, WKU FM (January 27, 2020), https://www.wkyufm.org/post/lge-proposes-largest-solar-field-kentucky#stream/0.

6 See *Browse Case Filings*, Kentucky Public Service Commission, https://psc.ky.gov/Case/ViewCaseFolders (last visited September 28, 2021).

7 *Incentives For Energy Independence*, DSIRE (July 16, 2021), https://programs.dsireusa.org/system/program/detail/2731/incentives-for-energy-independence

8 *See* Ky. Rev. Stat. § 1154.27-10.

9 *See* Ky. Rev. Stat. §§ 103.200-20.

10 *Id*.

[2] — Regulatory Scheme.

Generally speaking the Public Service Commission ("PSC") is the entity which exercises regulatory control over renewable energy development. There are two different regulatory schemes applicable to solar projects based upon the scale and type. The first is utility scale projects, which are larger in size and have higher voltage levels.[11] The second can be called "distributed energy resources" and consist of energy resources connected to the distribution system (less than 69 kv).[12] Each is discussed in turn below.

[a] — Utility Scale Projects.

There are three types of large-scale or "utility-scale" solar projects: (1) municipal electric projects, (2) regulated utility projects, and (3) merchant power plant projects.[13] A general discussion of each is included below.

1. A municipal electric project is a solar project taken on by a municipal utility that is owned by the community, run by a board of local officials who are ostensibly accountable to the citizens.[14]

2. A merchant power plant project is a plant development intended to generate and then sell power on the wholesale market. These are projects with a generating capacity of 10 MW or greater. Merchant power plants, and the attendant transmission lines, are subject to approval by the siting board of the PSC. The siting board focuses on (a) environmental matters not covered by permits, (b) economic impact, and (c) impact on Kentucky's electric transmission grid. The approval process beings with a notice of intent, then an ap-

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11 *Utility Scale Solar*, The Kentucky Solar Energy Society, https://kyses.org/page-1859990 (last visited September 28, 2021).

12 *Find Information on Distributed Energy Resources*, Ky.gov, https://eec.ky.gov/Energy/Pages/Find-Information-on-Distributed-Energy-Resources.aspx (last visited September 28, 2021).

13 *Kentucky Solar Toolkit*, Kentucky Solar Toolkit, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021).

14 *Id.*; *Kentucky Municipal Utilities Frequently Asked General Questions*, Kentucky Public Service Commission, https://psc.ky.gov/agencies/psc/industry/muni/5_FAQ-General.pdf (last visited September 29, 2021).

plication is filed. At that point, potential stakeholders are alerted and intervenors are allowed to voice their opinion or objection. Hearings follow, which precede the board decision. Should a party be unsatisfied with the board's decision, they may appeal it.[15]

3. A regulated utility project is a renewable energy production development undertaken by an existing utility that is already subject to regulation by the PSC. An example in Kentucky is the solar farms being built by Duke Energy. These projects require the PSC-regulated entity to seek a certificate of public convenience and necessity ("CPCN") from the PSC pursuant to KRS 278.020. After a regulated entity files its application for a CPCN, the proposal is evaluated and a formal evidentiary hearing is convened. The PSC then issues a decision via final order.[16]

In order to site any utility-scale solar project developers must comply with local zoning ordinances. While these are less prevalent in rural areas, they exist sporadically across the Commonwealth. Zoning is most frequently an issue with respect to required setbacks, the more challenging issue tends to be use issues. For instance, depending upon the definitions included in the ordinance, some communities have restricted renewable energy generation to industrial zones. These zoning ordinances should be a consideration for any developer at the outset when determining where to site a utility-scale project.

[b] — Distributed Energy Resources.

The most common distributed energy resources projects are customer-owned net metering installations. These are available through any Kentucky

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15 Ky. Rev. St. §§ 278.702-18; 807 Ky. Admin. Regs. 5:100-20; *Kentucky Solar Toolkit*, *Kentucky Solar Toolkit*, Kentucky Solar Toolkit, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021); *Kentucky's Electric Generation and Transmission Siting Process*, Kentucky Public Service Commission, https://psc.ky.gov/agencies/psc/siting_board/guide.pdf (last visited September 28, 2021).

16 Ky. Rev. St. §§278.020, 216; 807 Ky. Admin. Regs. 5:001§ 15; *Kentucky Solar Toolkit*, *Kentucky Solar Toolkit*, Kentucky Solar Toolkit, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021).

regulated entity, and the net metering laws allow qualifying customers to receive credit for energy generated by the customer. These laws are still an active incentive. However, the requirement for net metering has changed.

To qualify for net metering customers must own equipment that generates renewable energy; use said equipment on their property to generate a certain amount of electricity, up to 45 kilowatts; be connected in parallel with the utility's distribution system; and said equipment's primary purpose must be to supply all or part of the customer electricity requirement. Customers who meet the requirements will receive dollar credits that are subtracted from their total bill at a compensation rate determined by the Public Service Commission (PSC) in a rate proceeding for each utility.[17]

In order to take advantage of these incentives, residents, companies, and utilities must procure the appropriate permits prior to the installation of renewable energy equipment, i.e. solar panels. These projects must comply with local zoning requirements of the town/city/county in which it is located, which becomes an especially important issue when installed in urban areas. [18]

Conceptually similar to the small-scale, customer-owned net metering projects are larger scale, on-site facilities. Like the net metering projects, these installations allow for power to be generated "behind the meter", allowing customers to service their own electricity needs to the extent it can be provided by the installed renewable generation facility. Unlike the net metering projects, these can be either owned and maintained by the customer or the regulated entity, as negotiated between those parties. These projects are subject to zoning ordinances, building and electrical codes, state permitting, and local utility approval.[19] Recently, Kentucky Utilities and Maker's Mark installed a 560-panel generation facility at the Loretto, Kentucky distillery

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17 Ky. Rev. St. §§ 278.465-466

18 *Kentucky Solar Toolkit*, *Kentucky Solar Toolkit*, KENTUCKY SOLAR TOOLKIT, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021); *At a Glance*, ECAP, https://eec.ky.gov/Environmental-Protection/Compliance-Assistance/DCA%20Resource%20Document%20Library/PermitsAtaGlance.pdf (last visited September 29, 2021).

19 *Kentucky Solar Toolkit*, *Kentucky Solar Toolkit*, KENTUCKY SOLAR TOOLKIT, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021).

as part of that regulated entity's Business Solar Program to do exactly this.[20] Customers like Maker's Mark, with either large roofs or with land to spare, are typical of these larger-scale distributed energy projects.

Distributed energy resources provide additional opportunities. In net metering contexts and, depending upon the agreement, some larger distributed energy facilities, a customer retains Renewable Energy Certificates ("RECs"), which represent property rights for the environmental attributes for renewable energy generation. A REC is created when 1MWh of electricity is generated and delivered to the electricity grid from a renewable energy source.[21] RECs are assets which can be bought and sold,[22] and the value is often dependent upon the regulatory system of the state in which the purchaser is located.

[3] — Conclusion.

While many states have implemented regulation to encourage or require renewable energy adoption, Kentucky's solar industry growth is market-driven. There are no Renewable Portfolio Standards or Goals crated by the Commonwealth. However, renewable energy projects in Kentucky may take advantage of Federal incentives and Kentucky Industrial Revenue Bonds. In doing so, renewable energy developers must be careful to comply with state statutes, PSC regulation, and local zoning ordinances.

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20 *Maker's Mark 560 Panel Solar Array Power Bourbon Production in Loretto, Kentucky*, WDRB (February 20, 2020), https://www.wdrb.com/news/makers-marks-560-panel-solar-array-powering-bourbon-production-in-loretto-kentucky/article_e236a212-5424-11ea-b6d6-d3a78e3208a8.html.

21 *How the Green Energy Program Works*, LG&E KU, https://lge-ku.com/environment/green-energy-program/how-green-energy-program-works, (last visited September 28, 2021).

22 *Kentucky Solar Toolkit*, *Kentucky Solar Toolkit*, Kentucky Solar Toolkit, https://kentucky-solar-toolkit-kygis.hub.arcgis.com/ (last visited September 28, 2021).

§ 11.02. Ohio.

[1] — Introduction.

Prior to 2018, Ohio had no meaningful utility scale solar facilities. As of early 2022, however, Ohio has over forty utility scale solar projects in development[23] and more on the horizon.

Much of the project demand in Ohio is driven by the private sector, as internal and external forces are pushing companies to focus on sustainability in their Ohio-based operations. Amazon, for example, is directly involved in the development of 15 solar projects in the state with a combined capacity of almost 2,000 MW.[24]

In addition to growing corporate demand, political subdivisions in Ohio are increasingly seeking supply from in-state renewable resources, which is helping drive project development and financing. For example, residents of Ohio's largest city, Columbus, voted in November 2020, to form a municipal aggregation with the intent of procuring in-state renewable energy supply.[25] Another large city in the state, Cincinnati, is developing the largest municipal solar array in the country, capable of producing 203,000 MW each year to power to both municipal buildings and private residences.[26]

[2] — Regulatory Scheme for Utility Scale Solar.

The Ohio Power Siting Board (OPSB) has a comprehensive, multi-phased process for siting solar facilities that fall within the definition of a "major utility facility."[27] A solar project falls within this definition if it is "designed for, or capable of, operation at a capacity of fifty [50] megawatts or more." This

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23 Cases, Ohio Power Siting Board, https://opsb.ohio.gov/cases (last visited March 25, 2022).

24 Mark Williams, *Amazon to Develop Two More Solar Farms in Ohio*, The Columbus Dispatch (December 2, 2021, 10:18 AM), https://www.dispatch.com/story/business/2021/12/02/solar-farms-southwest-northwest-ohio-developed-amazon/8827186002/.

25 Press Release, The City of Columbus, Columbus Residents to Begin Receiving 100% Clean Energy in June (April 1, 2021) (available at https://www.columbus.gov/Templates/Detail.aspx?id=2147519805).

26 *Id*.

27 Ohio Revised Code ("R.C.") 4906.01(B)(1)(a).

definition also includes electric transmission lines and associated facilities of a design capacity of one hundred kilovolts or more.[28] It is likely that any associated battery energy storage system also falls within the jurisdiction of the OPSB, regardless of size.[29]

Ohio's regulatory scheme for utility scale solar underwent a significant change in late 2021. Beginning on October 11, 2021, before construction can begin on any solar facility of 50 MW or greater, a project must complete two levels of regulation. First, a project must submit to a preliminary review from the county where the project will be located. Then, if there is no objection from the county, the project must then proceed to obtain a certificate of environmental compatibility and public need from Ohio Public Siting Board (OPSB).

First, at the county level, at least 90 days but not more than 300 days prior to applying to the OPSB for a certificate or a material amendment to a certificate, a project must hold a public meeting in each county where the facility is to be located. Following this meeting, the county board of commissioners has 90 days to adopt a resolution prohibiting or reducing the proposed project in size. The resolution is binding on the OPSB. In addition, county boards of commissioners may designate all or part of an unincorporated area of the county as a "restricted area" in which all utility facility solar projects are prohibited.

Once a project has cleared the local level of regulation, it may apply to the OPSB for a certificate of environmental compatibility and public need (certificate). The Board is comprised of 11 members. Seven of those members are permitted to vote, and must include the Chairman of the Public Utilities Commission, the Director of the Environmental Protection Agency, the Director of the Department of Agriculture, the Director of the Development Services Agency, the Director of the Department of Health, the Director of the Department of Natural Resources, and a Governor-appointed engineer. The other four non-voting members are legislators. There are also two voting ad

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28 *Id*.

29 O.A.C. 4906-1-01(F).

hoc members of the OPSB: the chairperson of the township board of trustees and the president of the county board of commissioners, or their designee.

[3] — Financing Projects.

There are a number of tax incentivized financing options for solar development in Ohio. Utility scale renewable energy projects in Ohio can benefit from a real and tangible personal property tax abatement under the Qualified Energy Project ("QEP") framework with R.C. 5727.75. To be certified as a QEP, a project must submit an application to the Ohio Development Services Agency and receive approval by the county where the project is located. A county can approve the abatement by adopting a project specific resolution or by establishing itself as an "Alternative Energy Zone" COORDINATION WITH OTHER AUTHORITIES AND STAKEHOLDERS TAX ABATEMENTS 9 ("AEZ"), whereby county authorization is automatically granted to projects applying for QEP certification.[30]

In exchange for the abatement, the project must pay a payment–in-lieu-of taxes ("PILOT"). For solar projects, there is currently a minimum PILOT of $7k/ MW. The host County also has discretion to add up to an additional service payment amount of $2k/MW. The mandatory $7k/MW PILOT is distributed to the county and local taxing districts on a mileage basis. The discretionary additional service payment, if any, goes to the county general revenue fund.

The project must also meet other requirements designed to benefit the community including:

- Employ at least 80% Ohio-domiciled employees in construction
- Repair roads, bridges, and culverts affected by the construction
- Provide training to local first responders
- Coordinate with an Ohio university of apprenticeship program to establish an educational/training program

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30 Ohio Department of Development, https://development.ohio.gov/bs/bs_qepte.htm (last visited March 25, 2022).

The Ohio Air Quality Development Authority ("OAQDA") is another abatement program for projects that contribute to better air quality, such as solar projects.[31] OAQDA can provide the same level of property tax abatements as QEP but with flexibility regarding the terms of the PILOT to be negotiated by the project owner and affected jurisdictions. A project financed through OAQDA bonds receives a 100% exemption on real property, tangible personal property, and sales and use tax for qualified project costs, and interest on the bonds may be exempt from certain Ohio taxes. Here, too, coordination with local stakeholders is key. The project must obtain a Memorandum of Understanding (or some other preliminary acknowledgement or agreement) from the county, school district, and township(s) supporting the utilization of OAQDA financing and abatements, along with a summary of proposed payment terms and conditions to local governments.

[4] — Emerging Opportunities.

[a] — Brownfield Development.

Ohio has a number of historic and active traditional energy assets, landfills, and mining operations. Developers are beginning to view these underutilized and potentially contaminated properties as attractive sites for reclamation and solar development, or "brightfield" development.[32] As of early 2022, a number of projects sited on brownfield sites were in various stages of development before the OPSB.

[b] — Community Solar.

On October 12, 2021, members of the Ohio House of Representatives introduced a bill to permit community solar in Ohio.[33] The legislation authorizes the Public Utilities Commission of Ohio (PUCO) to certify up

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31 The OAQDA Clean Air Improvement Program website is located at https://ohioairquality.ohio.gov/Our-Services/Clean-Air-Improvement-Program.

32 *What is RE-Powering*, US EPA, https://www.epa.gov/re-powering/what-re-powering (last visited March 25, 2022).

33 H.B. 450, 134th Gen. Assemb., Reg. Sess. (Oh. 2021-2022) (available at https://search-prod.lis.state.oh.us/solarapi/v1/general_assembly_134/bills/hb450/IN/00/hb450_00_IN?format=pdf).

to 2,000 MW of community solar projects.[34] PUCO may also certify an additional 1,000 MW of community solar project constructed exclusively on "distressed sites," as long as the majority of these projects are located in the Appalachian region.[35]

Under the legislation, each community solar project cannot have a nameplate capacity of more than 10 MW, unless the project is located on a "distressed site." Projects constructed on distressed sites may have a nameplate capacity of up to 45 MW.[36]

A "distressed site" means a site of contiguous parcels where the majority of the acreage is: 1) a brownfield as defined under R.C. 122.65; 2) within an area where an investor may receive a new markets tax credit under section 45D of the Internal Revenue Code; and/or 3) a closed solid waste facility licensed by the environmental protection agency under R.C. 3734.02.[37] In addition to the increased nameplate capacity referenced above, community solar projects located on distressed sites shall be eligible to receive grant money awarded by the Ohio Department of Development from the brownfield remediation program under R.C. 122.6511 for costs associated with construction and remediation.[38]

From a consumer standpoint, a subscriber to a community solar project will be eligible for net metering.[39] However, a subscriber's share in a community solar project cannot represent more than 120% of their average annual electricity use.[40]

If the legislation passes, the PUCO is required to promulgate rules within six months of the legislation's effective date.[41]

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34 R.C. 4928.851(A).
35 R.C. 4928.851(B).
36 R.C. 4928.85.
37 R.C. 4928.85(B).
38 R.C. 4928.857(A).
39 R.C. 4928.67.
40 R.C. 4928.852.
41 R.C. 4928.859.

§ 11.03. Pennsylvania.

[1] — Introduction.

Pennsylvania's solar regulatory landscape is relatively meager when it comes to siting solar projects. Whereas in most energy-producing states the public utility commission plays a role in siting energy generation facilities,[42] in Pennsylvania, the jurisdiction of the Public Utility Commission ("PUC") over a solar project begins at the point of interconnection. The Pennsylvania Department of Environmental Protection ("DEP") regulates energy generation from coal and natural gas development through separate regulatory programs for each fuel source. In the absence of a similar program focused on solar energy generation, DEP treats grid-scale solar projects essentially like any large-scale real estate development. In fact, during a virtual Solar Energy Symposium hosted by Penn State's Center for Agriculture and Shale Law in June 2021, Robert Young, energy program specialist with DEP, reported that the regulation of solar energy development in the Commonwealth is primarily a local issue.

The biggest state regulatory hurdles to solar energy project siting arise out of Department of Agriculture programs designed to preserve prime farmland. While less regulation is usually seen as an advantage for any project's development, when it comes to large-scale solar projects, this lack of state regulation can bring uncertainty to the process. For example, where many other states preempt local zoning ordinances when a large-scale energy project obtains a permit from a state power siting board, most Pennsylvania projects will be subject to the whims of local zoning authorities.

While regulation of project siting is minimal and does not involve PUC, Pennsylvania's deregulation of the electric generation in the late 1990s and other policies aimed at advancing alternative energy and providing customer choice in the Commonwealth are beneficial to solar energy developers. Now, with proposed pro-solar legislation, such as enabling community solar and strengthening portfolio standards, moving through the General Assembly and

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42 Pennsylvania and Oklahoma are the only states in the nation where municipalities are the only entities with jurisdiction over energy generation siting.

the governor's efforts to regulate carbon dioxide through the administrative rulemaking process, developers are viewing Pennsylvania as a land of solar opportunity.

This chapter provides an overview of the regulation of solar energy development in Pennsylvania. It begins with a discussion of Pennsylvania's regulation of utility-scale solar projects, including Alternative Energy Portfolio Standards, state and utility incentive programs, retail wheeling, and permitting. It then addresses the Commonwealth's regulation of distributed solar, including net metering, interconnection processes, and proposed community solar legislation. Finally, this chapter concludes with a discussion of challenges and opportunities impacting solar energy development in Pennsylvania. Challenges include DEP's Abandoned and Orphan Well Program and Source Water Protection Program, Department of Agriculture programs designed to conserve prime farmland, and the Commonwealth's local zoning enabling act. Opportunities on the horizon include the potential for Pennsylvania to join the Regional Greenhouse Gas Initiative ("RGGI") and for development on active or abandoned mine sites and other brownfields.

[2] — Background.

Pennsylvania is the third largest net supplier of energy to other states behind Wyoming and Texas.[43] It ranks second in the nation in natural gas production, second in nuclear power generation, third in coal production, and is the second-largest exporter of coal to foreign markets.[44] Given this robust and diverse energy generation portfolio and relatively meager state incentives for renewable energy projects in the Commonwealth, the growth of solar photovoltaic energy generation in Pennsylvania has been relatively slow compared to many of its neighboring states to the east. In fact, of the 13 states in service territory of PJM Interconnection LLC ("PJM"),[45]

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[43] *Pennsylvania State Profile and Energy Estimates*, U.S. Energy Information Administration (October 21, 2021), https://www.eia.gov/state/analysis.php?sid=KY.

[44] *Id*.

[45] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West

Pennsylvania trails all but Kentucky and West Virginia in installed solar capacity.[46] But as the price of solar panels has dropped and coal and nuclear have struggled to remain economically viable, solar developers have recently turned their attention to Pennsylvania. Offering vast amounts of agricultural land and brownfields ripe for development, Pennsylvania has the potential to continue its legacy as a major power generator, especially as the nation transitions its fossil fuel-based economy to clean, renewable energy. In fact, Pennsylvania has more than 14 gigawatts of grid-scale solar energy generation currently in PJM's interconnection queue.[47] If all solar projects in line are ultimately developed, Pennsylvania would be producing more energy from solar than from either coal or nuclear in as little as four years.[48] [49] Now, with Pennsylvania poised to join RGGI and become the first major fossil fuel-producing state in the country to adopt a carbon pricing policy,[50] the future of solar energy generation in Pennsylvania is bright.

Virginia and the District of Columbia. It rates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 65 million people, making it North America's largest transmission grid. *See Who We Are,* PJM, https://www.pjm.com/about-pjm/who-we-are.aspx.

46 Christen Smith, *Solar industry tells lawmakers to incentivize growth in Pennsylvania*, The Record Online (September 6, 2021), https://therecord-online.com/site/archives/72965.

47 Anya Litvak, *With so much solar on the horizon, Pa. landowners are learning about a new type of lease*, Pittsburgh Post-Gazette (August 30, 2021), https://www.post-gazette.com/business/powersource/2021/08/30/solar-energy-grid-development-Pennsylvania-Pa-landowner-leases-electric-utilities-PJM/stories/202108290222.

48 *Id*.

49 Many of the projects in PJM's interconnection queue will not be developed, as PJM's system upgrade cost allocation process applied to renewable projects that tend to be sited further from end-users than fossil fuel generators resulted in an increase in projects saddled with network upgrade costs withdrawing from the interconnection queue and triggering restudies of projects later in the queue. Moreover, this "first to cause" cost system upgrade cost allocation has incentivized developers to make multiple interconnection requests for the same project so that if a project's first position in the queue triggers a system upgrade, the developer can withdraw the project from that queue position with the hopes that the project will avoid those costs at its next queue position. PJM's cost allocation process is a target of its Interconnection Process Reform Task Force, which plans to begin implementing reforms by October 2022.

50 Marc Levy, *Pennsylvania's carbon plan clears last regulatory hurdle*, AP News (September 1, 2021), https://apnews.com/article/business-pennsylvania-climate-change-a6a5985ff6a5bed396b40509c9f26f34.

[3] — Utility-Scale Solar.

Because of their size and reach, utility-scale solar projects represent the fastest way to reduce carbon emissions and transition away from fossil fuels. However, the large amounts of land required for these projects present serious hurdles to widespread development. Moreover, these projects generally interconnect to the transmission system, a process governed by PJM and, ultimately, the Federal Energy Regulatory Commission. Transmission level interconnection can be a complicated, costly, and time-consuming process. Nevertheless, the number of utility-scale projects being planned and developed in Pennsylvania is growing at an impressive rate. The Commonwealth's current and proposed Alternative Energy Portfolio Standards, state and utility incentive programs, deregulated power market and retail wheeling policies, and relatively painless permitting regime provide the regulatory framework necessary for utility-scale solar projects to proliferate in the state.

[a] — Alternative Energy Portfolio Standards.

Renewable or alternative energy portfolio standards are state policies requiring utilities to source a specified percentage of the electricity they sell from renewable or alternative energy sources.

Pennsylvania's Alternative Energy Portfolio Standards Act (the "AEPS Act")[51] was signed into law by former Governor Ed Rendell in 2004. The AEPS Act categorizes alternative energy resources into Tier I and Tier II and establishes minimum thresholds for the percentage of energy that utilities must utilize for each tier.[52] In addition, the AEPS Act includes a carve-out for solar photovoltaics, a Tier I resource.[53] It requires 0.5% of energy utilized in the state to come from solar photovoltaics by 2020. Electric distribution companies and generation suppliers who do not comply with AEPS must

51 73 P.S. § 1648.1, *et seq*.

52 73 P.S. § 1648.3.

53 *Id*.

purchase alternative energy credits ("AECs") to achieve compliance.[54] One AEC represents 1 MW of qualified alternative electric generation.[55]

Until recently, utilities were permitted to source solar energy from outside of Pennsylvania, resulting in a glut of out-of-state solar-sourced energy flowing into Pennsylvania and depressing the price of solar alternative energy credits. However, in 2017 the Pennsylvania General Assembly enacted the Alternative Energy Portfolio Standards Act 40 ("Act 40"), which required solar-credited projects to be built within Pennsylvania.[56]

Act 40's impact quickly became clear after it was implemented by the PUC at the end of Q1 in 2018. The price of solar alternative energy credits rose from an extreme low of $4 per credit in 2017 to $45 per credit in early 2019.[57] The price currently sits around $40 per credit.[58]

Pennsylvania is now poised to strengthen its Alternative Energy Portfolio Standards, including the solar carve-out. A pair of bipartisan bills, House Bill 1080 and Senate Bill 501, both introduced in April 2021, would increase the requirement of Tier 1 resources from 8% to 18% and increase the solar carve-out from 0.5% by 2020 to 1.75% by 2026. House Bill 1080 is pending before the House Environmental Resources and Energy Committee, and Senate Bill 501 is pending before the Consumer Protection and Professional Licensure Committee at the time of publication.

While these bills are a step in the right direction, the solar carve-out remains relatively miniscule compared to other Mid-Atlantic states and falls far short of the 10% solar by 2030 target proposed by the Pennsylvania DEP in its Pennsylvania Solar Future Plan in 2018.[59]

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54 *Id*.

55 *Id*.

56 73 P.S. § 1648.4.

57 Ben Adams, *Pennsylvania's SRECs Two Years After Act 40*, Sol Systems (Aug. 29, 2019), https://www.solsystems.com/pa-srecs-two-years-after-act-40/.

58 *Bid Prices for Pennsylvania – Last Twelve Months*, SRECTrade, https://www.srectrade.com/markets/rps/srec/pennsylvania (last visited Oct. 26, 2021).

59 Commonwealth of Pa. Dep't of Env. Prot., Pennsylvania's Solar Future Plan (November 2018) (available at http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=1413595&DocName=PENNSYLVANIA%26%2339%3bS%20SOLAR%20

[b] — State and Utility Incentive Programs.

In addition to the Solar Alternative Energy Credit Program instituted as part of the AEPS Act, Pennsylvania and its electric utilities offer two other types of incentive programs for solar energy development in the Commonwealth.

Four Sustainable Energy Funds ("SEFs") were created by the PUC in the late-1990s as part of a settlement with five electric utilities following the Commonwealth's deregulation of the electric utility market. The four funds, each operated by its own board of directors, include (1) West Penn Power Sustainable Energy Fund,[60] (2) Metropolitan Edison Company and Pennsylvania Electric Company Sustainable Energy Fund,[61] (3) Sustainable Energy Fund of Central Eastern Pennsylvania,[62] and (4) Sustainable Development Fund.[63] The statewide Sustainable Energy Board was formed in 1999 to improve coordination between the SEFs and state agencies.[64] It consists of representatives from the PUC, DEP, the Department of Community and Economic Development, the Office of Consumer Advocate, the Pennsylvania Environmental Council, and each regional fund's board.[65] Since their inception, SEFs have provided more than $20 million in loans and $1.8 million in grants to over 100 renewable energy and sustainability projects in Pennsylvania.[66]

The Solar Energy Program ("SEP"), administered jointly by the Department of Community and Economic Development and the DEP under the direction of the Commonwealth Financing Authority, provides grants, loans, and loan guarantees to businesses, economic development

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FUTURE%20PLAN.PDF%20%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e).

60 PUC Docket No. M-00031715F0005.

61 PUC Docket No. M-00031715F0004.

62 PUC Docket No. M-00031715F0003.

63 PUC Docket No. M-00031715F0002.

64 *Sustainable Energy Fund*, Pennsylvania Public Utility Commission, https://www.puc.pa.gov/electricity/sustainable-energy-fund/ (last visited Oct. 26, 2021).

65 *Id*.

66 *Id*.

organizations, and political subdivisions to support activities that promote the generation and use of solar energy and the manufacture or assembly of solar equipment.[67] After a hiatus caused by restructuring that began in 2012, SEP resumed accepting applications in late 2017, shortly after the General Assembly enacted Act 40.[68]

[c] — Deregulated Power Market and Retail-Wheeling.

Retail wheeling is "the process of moving electric power from a point of generation across third-party-owned transmission and distribution systems to a retail customer."[69] States that adopt retail wheeling policies permit retail electricity customers to use the transmission and distribution system of a utility to purchase power from a different supplier. Retail wheeling is vital to the viability of utility-scale solar projects, which are typically sited farther from the end-user than traditional fossil fuel generation and must have access to the transmission and distribution systems to deliver power to customers without having to sell directly to the utility.

Pennsylvania adopted retail wheeling when it deregulated its energy market in the late 1990s with the enactment of the Electricity Generation Customer Choice and Competition Act, ("EGCCC"). Passed in 1996, EGCCC took effect statewide in 2000 after a pilot program.[70] It required electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to Pennsylvania consumers.[71] With some exceptions, EGCCC ended the regulation of electricity generation as a public utility function. It also established the PUC's Standard Offer Program,

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67 *Solar Energy Program (SEP)*, Commonwealth of Pa. Dep't of Community and Economic Develop., https://dced.pa.gov/programs/solar-energy-program-sep/ (last visited Oct. 26. 2021).

68 *See* Section 11.03(1), above.

69 Glossary: R, U.S. Energy Information Administration, https://www.eia.gov/tools/glossary/index.php?id=R (last visited Oct. 26, 2021).

70 66 Pa. C.S.A. § 2801, *et seq*.

71 *Id*.

which provides consumers who procured an alternate power supplier with a fixed rate at a 7% discount versus their electric distribution company's price-to-compare for 12 months, at which point the consumer could either opt out or remain with the alternate supplier at its market rate.[72]

[d] — Permitting.

First issued in January 2019 and revised in April 2021, DEP's Chapter 102 Permitting for Solar Panel Farms Frequently Asked Questions is intended to clarify the DEP's interpretations concerning applicability and implementation of National Pollutant Discharge Elimination System (NPDES) permits for stormwater discharges associated with construction activities, including erosion and sediment control and post-construction stormwater management for solar panel farms with one acre or greater of earth disturbance.[73] The document specifies that it does not affect regulatory requirements, but provides "a framework within which DEP and delegated county conservation districts will exercise administrative discretion in the future.[74] DEP reserved the right to deviate from the interpretations in its FAQs if warranted by the circumstances of a given project.[75]

[4] — Distributed Solar.

Distributed solar projects are sited close to the end-user and interconnected to the local electric distribution system rather than the transmission system. These projects are smaller than utility-scale projects and range from residential rooftop solar to community solar farms providing electricity to a whole host of residential, commercial, and industrial subscribers. Distributed solar is vital to the energy transition because there are fewer roadblocks to completing

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72 66 Pa.C.S.A. § 2806.

73 *Chapter 102 Permitting for Solar Panels: Frequently Asked Questions*, Commonwealth of Pa. Dep't of Env. Prot., https://files.dep.state.pa.us/Water/BPNPSM/StormwaterManagement/ConstructionStormwater/Solar_Panel_Farms_FAQ.pdf (Ver. 1.1, Apr. 30, 2021).

74 *Id*.

75 *Id*.

projects in a timely manner. Interconnecting to the distribution system through the local utility is a more streamlined process than interconnecting a 100 MW solar farm to the transmission system through the regional ISO. While PJM's current interconnection queue will take five years to clear absent robust reforms to its interconnection and cost allocation process, a 5 MW community solar project can typically begin generating power into the distribution system in less than a year after interconnection request. The greater the adoption of distributed solar, the less costly transmission infrastructure will need to be built to accommodate the energy transition. To accommodate distributed alternative energy projects, Pennsylvania offers net metering at the retail rate and streamlined interconnection policies for projects interconnecting with the electric distribution utility. Moreover, bi-partisan community solar enabling legislation pending in the General Assembly is a potentially lucrative opportunity for developers.

[a] — Net Metering.

State net metering policies allow utility customers who install solar panels (or other electricity-generating facilities) at their homes and businesses to sell electricity generated by the customer to the utility at a retail rate and receive credit on their electric bill.[76]

In Pennsylvania, the AEPS Act provides for net metering at a full retail rate for excess generation for "customer-generators."[77] Customer-generators are the only category of generators entitled to utilize net metering. The Act defines "net metering" as:

> The means of measuring the difference between the electricity supplied by an electric utility and the electricity generated by a

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[76] State Net Metering Policies, NATIONAL CONFERENCE OF STATE LEGISLATURES, https://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx#:~:text=Net%20metering%20policies%20allow%20distributed,credit%20on%20their%20utility%20bill.&text=Increasing%20numbers%20of%20utility%20customers,generate%20electricity%20on%20their%20property (last visited Oct. 26, 2021).

[77] 73 P.S. § 1648.5.

> customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator's requirements for electricity.

The term "customer-generator" is defined as "[a] nonutility owner or operator of a net-metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations." Thus any utility customer whose solar generating system does not exceed the capacity limits of the AEPS Act (50kW for residential and 3 MW for any other customer) may take advantage of net metering so long as *any portion* of the electricity generated by the system is used to offset that customer's electricity purchases from the utility. Customer-generators with systems between 3 MW and 5 MW may take advantage of net metering if they "make their systems available to operate in parallel with the electric utility during grid emergencies … or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure," subject to technical and interconnection rules promulgated by the PUC and the Institute of Electrical and Electronic Engineers for generators interconnected with an electric distribution company, electric cooperative or municipal electric system. [78]

Net metering eligibility is also extended to "[v]irtual meter aggregation on properties owned or leased and operated by a customer-generator and located within two miles of the boundaries of the customer-generator's property and within a single electric distribution company's service territory."[79] This provision permits farms and businesses who own or lease multiple properties in an area, each with its own meter but all under one account, to aggregate energy production across locations so long as each property has its own on-site baseload (i.e., each property draws some amount of electricity from the grid and does not only generate energy into the grid).

78 73 P.S. § 1648.2.

79 *Id*.

The technical and interconnection rules promulgated by PUC to implement net metering pursuant to the AEPS Act were challenged as outside the scope of PUC's statutory authority and therefore invalid and unenforceable in *Hommrich v. Pa. PUC*.[80] In *Hommrich*, an electric customer[81] challenged the PUC's net metering regulations with respect to the definitions of "customer-generator," "utility," and "virtual meter aggregation." The plaintiff also challenged the requirement that applications for proposed net metering systems with a nameplate capacity greater than 500 kilowatts must be approved by the PUC, as well as the requirement that large customer-generators (nameplate capacity between 3 MW and 5 MW) demonstrate their ability to provide emergency support consistent with the RTOs tariff or provide maintenance to critical infrastructure.[82]

Regarding the challenged PUC definitions of "customer-generator" and "utility," the court determined that PUC acted outside the scope of its legislative authority by adding an additional requirement that a "customer-generator" be a *retail electric customer* that is a nonutility owner and that a "utility" includes a business, person, or entity whose primary purpose is, *inter alia*, the generation of electricity.[83] The AEPS Act did not define utility, but as discussed in Section 11.03(3), above, the EGCCC essentially ended the regulation of electricity generation as a public utility function. In short, the PUC's purpose was to restrict those in the business of energy generation, regardless of the system's nameplate capacity, from net metering eligibility. With 2007 amendments to the AEPS Act, however, the General Assembly sought to expand, not restrict, sources of alternative energy generation. Recognizing the legislature's intent, the court stated:

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80 Hommrich v. PA. PUC, 231 A.2d 1027 (Cmmw. Ct. 2020).

81 The customer was David Hommrich, who constructed a solar farm for the purpose of selling nearly all the energy generated to the EDC at the full retail rate. Anya Litvak and Laura Legere, *A scrappy solar developer took utility regulators to court. And won.*, Pittsburgh Post-Gazette (March 4, 2021), https://www.post-gazette.com/business/powersource/2021/03/04/Solar-energy-David-Hommrich-Pennsylvania-PUC-utilities-West-Penn-Power-electricity-net-metering/stories/202102250167.

82 Hommrich v. Pa. PUC, 231 A.3d 1027, 1032 (Cmmw. Ct. 2020).

83 *Id*. at 1044.

> Prior to the 2007 amendments, the definition of "net metering" measured "the electricity generated by a customer-generator when the *renewable* electricity generated by the alternative energy generating system is *intended primarily* to offset part or all of the customer-generator's requirements for electricity." *Former* 73 P.S. § 1648.2 (2007) (emphasis added). Under the current definition, a nonutility owner or operator of a net-metered facility may utilize net metering so long as "*any portion*" of the electricity that the customer-generator generates is used to offset part of the customer-generator's electrical requirement. 73 P.S. § 1648.2 (emphasis added).[84]

The court invalidated the definition of "virtual meter aggregation" on similar grounds.[85] The definitions provided by the statute now determine eligibility for net metering.

The court upheld the PUC regulations requiring that (1) applications for proposed net metering systems with a nameplate capacity greater than 500 kilowatts must be approved by the PUC, and that (2) large customer-generators demonstrate their ability to provide emergency support consistent with the RTOs tariff or provide maintenance to critical infrastructure, ruling that they were within the scope of PUC's rulemaking authority and consistent with the AEPS Act.[86]

The Supreme Court of Pennsylvania affirmed the lower court's decision on February 17, 2021.[87]

[b] —Interconnection.

Distributed solar projects interconnect with the electric distribution system rather than the transmission system through a process governed by the state public utility instead of the regional transmission operator.

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84 *Id*. at 1039.

85 The PUC's definition improperly added a new component that the customer-generator must have a "measurable electric load independent" of the customer-generator's system. 52 Pa. Code § 75.12.

86 Hommrich v. Pa. PUC, 231 A.3d 1027, 1039 (Cmmw. Ct. 2020).

87 Hommrich v. Commonwealth, 245 A.3d 637 (Mem) (Pa. 2021).

This arrangement is beneficial to the project owner or developer because interconnecting with the distribution system tends to be a quicker and more streamlined process and permits net metering.

Pennsylvania PUC's Interconnection Standards applicable to customer-generators with small generation facilities with a nameplate capacity of 5 MW or less, not subject to PJM's interconnection requirements and designed to operate in parallel with the electric distribution system, are promulgated at 52 Pa. Code § 75.31, *et seq.* Customer-generators submit interconnection requests to the electric distribution company ("EDC") that owns the distribution system where interconnection is sought.[88] The regulations establish four tiers of EDC review procedures for evaluating interconnection requests:

- **Level 1** — Inverter-based facility with nameplate capacity of 10 kW or less and certified interconnection equipment.
- **Level 2** — Inverter-based facility with nameplate capacity of 2 MW or less and certified interconnection equipment, proposing interconnection to a radial distribution circuit or a spot network limited to serving one customer, which has been reviewed but not approved under Level 1 review procedures.
- **Level 3** — Facility with nameplate capacity of 2 MW or less, which does not qualify under Level 1 or Level 2 procedures.
- **Level 4** — Available to interconnection customers that do not qualify for Level 1 or Level 2 review and do not export power beyond the point of common coupling; provides for potentially expedited review process.[89]

EDCs must apply IEEF 1547 and U.L. 1741 technical standards when evaluating all interconnection requests under Level 1 through 4 reviews.[90]

Additionally, EDCs must evaluate small generator facilities requesting interconnection for multiple energy production devices at a single point of

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88 52 Pa. Code § 75.32. EDC's must also establish an electronic application process. *Id.*

89 52 Pa. Code § 75.34.

90 52 Pa. Code § 75.35.

interconnection based on the aggregate nameplate capacity.[91] EDCs may not unreasonably refuse a customer-generator's request to interconnect multiple generation facilities at a single point of interconnection, and if the EDC proposes a single point of interconnection for multiple generating facilities and the customer-generator rejects the proposal, the customer-generator must pay the full cost of a separate point of interconnection for each facility.[92] Small generator facilities must also install a device between the facility(ies) and point of interconnection capable of isolating the facility from the EDC, but the isolation device must also be accessible to the EDC.[93]

[c] — Proposed Community Solar Enabling Legislation.

"Community solar" is used to describe solar projects interconnected to the distribution system that provide electricity to multiple customers or subscribers and are located at a different site from the end-users.[94] Community solar projects allow customers who cannot install solar panels on their own property to procure solar energy directly from the generator using the utility's distribution system.

If passed, bipartisan Senate Bill 472 and House Bill 1555 would enable Pennsylvania community solar projects where two or more entities may subscribe for electricity generated by an offsite solar energy system with up to 5 MW of capacity. The bills provide flexibility in structuring the ownership, development, and subscription administration of the solar energy systems. Community solar projects would interconnect to the distribution system and subscribers must reside within the same service territory of the EDC to which the project is interconnected. Optimism that the General Assembly is motivated to enable community solar projects has already led

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91 52 Pa. Code § 75.36 (1).

92 52 Pa. Code § 75.36 (8).

93 52 Pa. Code § 75.36 (9).

94 *Community Solar Basics*, U.S. Dep't of Energy, Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/solar/community-solar-basics (last visited Oct. 25, 2021).

some companies to seek investors for and begin planning these projects in Pennsylvania as of this publishing.

Community solar projects provide certain benefits to their stakeholders compared with other forms of solar energy generation. First, they typically reach commercial operation much faster than grid-scale projects. Whereas community solar projects interconnect with the EDC's distribution system in a relatively streamlined process, grid-scale projects typically languish in PJM's interconnection queue for years—current estimates project that it will take four to five years to interconnect all projects now in queue.[95] PJM Interconnection Process Reform Taskforce is exploring approaches to reduce interconnection times.[96] Second, community solar projects alleviate the need to construct new, large-scale and expensive transmission lines. These types of projects also allow anyone serviced by a electric distribution utility to procure solar energy directly from a specific project when their circumstances do not permit installation of a solar system on their own property.

[5] — Challenges.

Some laws and programs that are generally applicable to any large real estate development in Pennsylvania present challenges to solar energy projects. Programs administered by DEP and the Department of Agriculture, as well as the Municipalities Planning Code, which enable local municipalities to enact their own zoning ordinances, have caused problems for solar developers seeking to site their projects. Moreover, a bill working its way through the General Assembly would require solar developers to post bond to secure the decommissioning of the project.

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95 PJM New Services Queue Analysis for Interconnection Process Reform Task Force, Amazon Web Services, (August 4, 2021) (available at: https://www.pjm.com/-/media/committees-groups/task-forces/iprtf/2021/20210804/20210804-item-02a-aws-queue-analysis.ashx).

96 *Interconnection Process Reform Task Force*, PJM Interconnection, https://www.pjm.com/committees-and-groups/task-forces/iprtf (last visited Oct. 25, 2021).

[a] — Department of Environmental Protection Programs.

DEP administers the Commonwealth's Abandoned and Orphaned Well Program and Source Water Protection Program, both applicable to solar farms.

Pennsylvania's Oil and Gas Act[97] authorizes DEP to plug orphaned and abandoned oil and gas wells to address environmental, health, and safety concerns. It imposes a duty on any person who discovers an abandoned oil and gas well to notify DEP within 60 days of discovery.[98] Nothing about this statutory duty is specific to solar energy developers, but DEP is alerting solar developers to this duty because of the large swaths of land developers must control to site a utility-scale solar project. DEP expects solar developers to conduct due diligence regarding the potential for abandoned wells located on the project site. DEP's Office of Oil and Gas Management recommends[99] that solar developers perform at least the following activities as part of the site evaluation and design process:

- Conduct title searches for oil and gas leases and other mineral development rights and if the project site is so encumbered, incorporate accommodations[100] for these mineral development activities into the
  project design.
- Review DEP geographic information system (GIS) tool to locate active or inactive/abandoned wells on the property, and if any oil and gas infrastructure is identified on the property that is not identified by the GIS tool, immediately report the discovery to DEP. Wells discovered during design or construction must be

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97 58 Pa. C.S. § 3201, *et seq.*

98 58 Pa.C.S.A. §3213(a.1).

99 *Solar Developer Resources*, Commonwealth of Pa. Dep't of Env. Prot., https://www.dep.pa.gov/Citizens/solar/Pages/Developers.aspx (last visited Oct. 25, 2021).

100 Here, DEP appears to be referencing the judicially created accommodation doctrine, which holds that the "mineral and surface estates must exercise their respective rights with due regard for the other's," and has in general provided a "sound and workable basis" for resolving conflicts between ownership interests. Lyle v. Midway Solar, *LLC*, 2020 WL 7769632, *6 (2021).

plugged or the design must be modified to allow DEP access for eventual plugging.
- Consider potential ignition sources and sources of static electricity, incorporate appropriate setbacks from oil and gas infrastructure in the project design, use devices that are intrinsically safe (*i.e.*, not an ignition source), and include emergency access and safety considerations for this infrastructure in any development plan.

DEP also coordinates with local governments to implement its Source Water Assessment and Protection Program in accordance with the federal Safe Drinking Water Act and pursuant to the Pennsylvania Safe Drinking Water Act and the Clean Streams Law. DEP recommends that grid-scale solar developers use the GIS tool it provides to determine whether their projects are located in a Public Water Supply Service Area.[101] If so, the developer must notify the relevant water supply agency and coordinate with it during development.

[b] — Department of Agriculture Programs.

The Pennsylvania Department of Agriculture operates the Commonwealth's Clean and Green Program, Agricultural Security Area Program, and Conservation Easement Purchase Program.

The Clean and Green Program provides preferential tax treatment to agricultural lands enrolled in the program. Utility-scale solar projects may not be sited on land enrolled in this program, but landowners can break the program covenant to install a solar array if they pay back taxes for the period of enrollment, which taxes can be covered by the developer.

The Agricultural Security Area and Conservation Easement Programs, however, pose a greater hurdle to solar energy project siting. If a farmer includes land in a qualifying Agricultural Security Area, state or local governments can purchase conservation easements from the farmer encumbering the land, which exist in perpetuity and prevent the landowner

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101 *Solar Developer Resources*, Commonwealth of Pa. Dep't of Env. Prot., https://www.dep.pa.gov/Citizens/solar/Pages/Developers.aspx (last visited Oct. 25, 2021).

from engaging in commercial solar development on the land. Therefore, utility-scale solar developers must ensure that land selected for development in Pennsylvania is not subject to a conservation easement. However, if more than 50% of energy generated is used on the premises, the system does not violate the covenants of the conservation easement.

[c] — Land Use and Zoning — The Municipalities Planning Code.

Perhaps the highest hurdle to siting a solar energy project is local land use and zoning regulation. The enabling legislation for local land use and zoning regulation in Pennsylvania is the Municipalities Planning Code ("MPC").[102] The MPC establishes a uniform approach for enacting, enforcing, and amending land use and zoning laws for every municipality and county in Pennsylvania, excepting the Commonwealth's two largest cities, Philadelphia and Pittsburgh.[103] The MPC provides procedural requirements counties and municipalities must follow in administering their land use and zoning regimes and the procedure for aggrieved persons to challenge those regimes before local boards of supervisors, with appeals made first to the Courts of Common Pleas, then to the Commonwealth Court,[104] and finally to the Supreme Court of Pennsylvania.

Under the MPC, municipalities are not required to enact land use and/or zoning ordinances, but counties are required to at least adopt a comprehensive plan.[105] Where a county adopts a land use or zoning ordinance, it controls in the absence of a municipal or township zoning ordinance.[106] While the MPC exempts buildings used by public utilities from local zoning ordinance if the

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102 53 P.S. § 10101, *et seq.*

103 Allegheny West Civic Council, Inc. v. Zoning Bd. of Adjustment of City of Pittsburgh, 94 A.3d 450, 454 (Pa. Cmmw. 2014).

104 The Commonwealth Court is one of two intermediate appellate courts in Pennsylvania. It exercised jurisdiction primarily over matters involving state and local governments and regulatory agencies. The other intermediate appellate court is the Superior Court.

105 53 P.S. § 10301.4.

106 53 P.S. § 10602.

public utility successfully petitions the PUC for a finding that the building is reasonably necessary for the convenience and welfare of the public,[107] electric generation suppliers[108] are not considered public utilities in Pennsylvania.[109] Therefore, a zoning certificate is required for any community solar project developed in a township with an applicable zoning ordinance.

Mohamed Badissy, assistant professor of law at Penn State Dickinson School of Law, led a team examining zoning ordinances in more than 2,500 Pennsylvania municipalities for specific regulations of solar energy projects. His team found that only 5% of zoning ordinances allowed for solar energy as a principal use of land in any zoning district, usually subject to approval as a conditional use.[110] In 8% of the ordinances reviewed, solar energy generation is permitted only as an accessory use, with solar as a principal use of land either implicitly or explicitly prohibited.[111] Eighty-seven percent (87%) of Pennsylvania municipal zoning ordinances either make no mention of solar energy or fail to specify where or under what circumstances it is permitted.[112]

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107 53 P.S. § 10619.

108 An "electric generation supplier" or "electricity supplier" is defined as "[a] person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an electric distribution company. The term excludes building or facility owner/operators that manage the internal distribution system serving such building or facility and that supply electric power and other related power services to occupants of the building or facility. The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives). 66 P.S. § 2803.

109 66 Pa.C.S.A. § 102.

110 Mohamed R. Badissy, PA Solar Ordinances: Local Regulation and National Trends at the Penn State University Solar Law Symposium (June 17, 2021) (available at https://aglaw.psu.edu/wp-content/uploads/2021/07/PSU-Solar-Law-Symposium-Day-2-session-5-Badissy.pdf).

111 *Id.*

112 *Id.*

Local zoning ordinances present important issues for solar developers because a lack of guidance creates the risk of delay and increases costs, which can negatively impact project economics. Accordingly, townships hoping to attract solar energy development should consider addressing the use specifically in their zoning ordinances and seek input from industry experts in the process. Several Pennsylvania counties, including Cumberland, Dauphin, Lancaster, Monroe, Montgomery, Perry, and York, have drafted model solar energy ordinances for use by municipalities seeking to update or create their own ordinances.

[d] — Proposed Legislation- Bonding Requirements.

The Republican-sponsored Senate Bill 284 was first introduced in February 2021 and would require the operator of any "alternative energy production project," including utility-scale solar, to post a bond with DEP for the duration of the project's operation until a reclamation plan is completed. The amount of the bond would be proportionate to the costs related to potential hazardous liabilities, site decommissioning and reclamation, and proper recycling or disposal of the wind and solar facilities at the end of their useful life.[113]

[6] — Opportunities.

[a] — Regional Greenhouse Gas Initiative.

Pennsylvania is on track to join the Regional Green House Gas Initiative ("RGGI") in 2022. RGGI is a market-based carbon trading system among eleven Northeast and Mid-Atlantic states. It is the first multi-state, market-based program in the U.S. designed to reduce carbon dioxide emissions in the electric power sector.[114]

Governor Tom Wolf is leading the effort to join RGGI through the administrative rulemaking process under the authority of the Pennsylvania

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113 SB 284, § 4304 – 4305.

114 *Elements of RGGI*, The Regional Greenhouse Gas Initiative, https://www.rggi.org/program-overview-and-design/elements (last visited Oct. 25, 2021).

Air Pollution Control Act.[115] The proposed rule allowing Pennsylvania to join RGGI has successfully cleared all administrative hurdles and is set to become effective as soon as it is published in the Pennsylvania Bulletin. Republican efforts in the state legislature to block the executive action with a veto-proof majority have thus far failed. However, Pennsylvania's Legislative Reference Bureau has refused to publish the final rule, arguing that the legislature has more time to assemble a veto-proof majority in opposition to the rule.[116] The Wolf administration sued the Legislative Reference Bureau in February 2022 in an original action before the state's Commonwealth Court to force the agency to publish the final rule.[117] If the administration prevails in the case and the final rue is published, the Republican-led legislature will likely bring its own suit to block the rule from taking effect, arguing that the governor's administration exceeded its authority in promulgating the rule.

Pennsylvania's Air Pollution Control Act gives the Environmental Quality Board ("EQB") and DEP the authority to (1) implement federal pollution control standards under the Clean Air Act and (2) adopt additional state-specific pollution control standards pursuant to other provisions of the act, which bestows upon the EQB the power and duty to prevent, control, reduce, and abate air pollution in the Commonwealth through setting maximum allowable emission rates for air contaminants from air contamination sources.[118] This authority appears sufficiently broad to encompass the carbon emission regulations promulgated by the EQB to join RGGI, but a lawsuit challenging the EQB's authority could delay implementation of the regulations long enough to give Republicans a chance to take control of the governorship in the next election and pull Pennsylvania out of RGGI before its carbon reduction targets are implemented.

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115 35 P.S. § 4001, *et seq.*

116 *Governor sues to force carbon-pricing plan to take effect*, Associated Press (February 3, 2022), https://apnews.com/article/climate-business-environment-legislature-state-governments-34f9972a7652c43ac2b3cea69ad8e116.

117 *Id*.

118 35 P.S. § 4005(a).

If the rule ultimately takes effect, Pennsylvania would be the first major fossil fuel producing state in the U.S. to adopt a carbon pricing policy.

[b] — Brownfield Development.

Pennsylvania's prominent position in our nation's energy landscape, combined with vast amounts of farmland protected by agricultural conservation easements and challenging local zoning regimes, make siting solar energy projects on brownfields an important opportunity for the Commonwealth. Old coal mines that are inappropriate for most types of redevelopment abound in Pennsylvania, and solar projects are an excellent use for such land. Even active coal mines present opportunities to solar developers as coal companies increasingly seek to co-locate renewable energy projects with their mining operations and the electricity produced from coal becomes increasingly disfavored and uneconomical.

Solar projects sited on brownfields may qualify for federal tax incentives and credits.[119] Brownfields also allow projects to leverage existing infrastructure, reduce project cycle times through streamlined permitting and zoning, reduce land costs, and gain community support through the land revitalization efforts.[120]

Pennsylvania has already seen a trend around siting solar projects on brownfields, and that trend is expected to continue as more solar developers enter the Commonwealth.

[7] — Conclusion.

Pennsylvania is poised to become one of the largest solar energy-producing states in the Mid-Atlantic. Utility-scale projects benefit from Pennsylvania's Alternative Energy Portfolio Standards, state and utility

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119 *Supporting Brownfields Redevelopment using Tax Incentives and Credits*, U.S. EPA, https://www.epa.gov/brownfields/supporting-brownfields-redevelopment-using-tax-incentives-and-credits-0 (last visited Oct. 26, 2021).

120 Re-Powering America's Land Initiative: Program Overview, at 4, U.S. EPA, https://www.epa.gov/sites/default/files/2021-03/documents/re_on_cl_program_overview_508_031121.pdf (March 2021).

incentive programs, deregulated power market and retail wheeling policies, and relatively painless permitting regime. Distributed solar projects likewise benefit from the Commonwealth's net metering and interconnection policies and may soon have the opportunity to develop community solar projects under the authority of proposed legislation that enjoys bipartisan support. While regulatory programs administered by the state's Departments of Environmental Protection and Agriculture present some hurdles to solar development, Pennsylvania will likely see a dramatic acceleration of projects entering the pipeline if Governor Tom Wolf succeeds in joining the Commonwealth in RGGI and capping allowable carbon dioxide emissions. Pennsylvania's long history as an energy producer means there are plenty of brownfields ripe for solar development. While there remain plenty of legislative and regulatory opportunities for Pennsylvania to become more accommodating to solar energy development, the future of solar energy in the Commonwealth is bright.

§ 11.04. West Virginia.

As a historically coal and natural gas rich state, West Virginia's energy economy is one that is in a bit of transition now as more solar and wind generation projects are developed in the state. West Virginia state policymakers are focused on recruitment of large manufacturing investment into the state and understand that significant investments are being driven by the availability of renewable energy. Thus, West Virginia is beginning to see significant expansion of renewable capacity largely driven by the market.

Similar to Kentucky, West Virginia does not have a renewable portfolio standard or established renewable energy goals and is currently being driven entirely by market forces. However, West Virginia is a fully regulated state, so from the perspective of utility and distributed solar generation, the state Public Service Commission (PSC) is really the most significant body that has a say in how solar, wind, and renewable energy generation develops. The most significant hurdle that a utility scale solar project faces in launching is the receipt of a Certificate of Public Convenience and Necessity from the PSC. In the past three years, the West Virginia state legislature has recognized the need for those projects to be brought online more quickly, and shortened the

window for the PSC to issue this certificate to 180 days. As of the time of publication, the PSC is turning around those applications even more quickly than the statutory requirement.

West Virginia is a state without third-party power purchase agreements, so it heavily relies on partnerships between the generators and the electricity utilities. The line between what is permissible and what is not with respect to on-site generation sometimes becomes blurred. For example, is it permissible for a third party to rent generation equipment to an end user for self-generation on the user's own property? Prevailing West Virginia law here holds that is permissible though there is some ambiguity in the law. The manufacturing industry has raised this and other ambiguities as potential reforms for legislative consideration.

For distributed solar, there is a net metering statute in West Virginia, but like the state of Ohio, it is credited only against the electricity. For many customers, the demand charges and the charges incidental to the actual commodity itself can sometimes swamp the actual cost of the electricity. Often individuals and entities who made investments in distributed solar are not able to recoup those investments to the fullest extent possible under the existing law. This is the subject of ongoing discussion between the organizations that represent distributed solar users and distributed solar installers and the electric utilities.

The incumbent public utilities do offer green tariff provisions, which are regulated by the PSC, and are utilized. Virtual power purchase agreements are in place with the utilities. Ultimately, however, as an artifact of being a fully regulated state, it all comes back to how an end user in West Virginia can work with the incumbent utilities. The regulatory structure for solar energy in West Virginia does in many ways mirror that of Kentucky.

Because of the mountainous terrain, West Virginia has historically been stronger in wind energy generation than solar generation but is beginning to see solar capacity come online now. The advantage of being a state of significant wind energy generation for two decades is the understanding that there are some incentives in place that wind energy developers take advantage of regularly, such as the pilot programs for payments in lieu of

taxes and provisions of tax law that provide that the actual generating assets themselves can be taxed under certain circumstances at salvage value. Solar developers are asking the West Virginia legislature for clarity on whether all renewable energy generation capacity can be treated the same for purposes of applicable state and local taxes.

Chapter 12

Energy Litigation Update for 2021

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§ 12.01. Introduction.

The following chapter provides a summary of noteworthy oil and gas decisions issued by courts throughout the region and other oil and gas producing jurisdictions in the United States throughout 2020 and early 2021.

§ 12.02. Pennsylvania.

[1] — Royalties and Post-Production Costs.

[a] — *Coastal Forest Resources Co. v. Chevron USA, Inc.*

Coastal Forest Resources Co. v. Chevron USA, Inc.[1] involved claims challenging the calculation of oil and gas royalties that included post-production costs. The relevant royalty provision in the oil and gas lease provides as follows: "Gas: To pay Lessor as royalty … 15.625% of the gross sales price received by Lessee from the sale of such gas and the constituents thereof at the wellhead." The United States District Court for the Western District of Pennsylvania granted defendant Chevron USA, Inc.'s motion to dismiss, holding that the inclusion of "wellhead" language in the oil and gas lease at issue permitted the use of the net-back method for calculating oil and gas royalties. The District Court rested its decision largely on the Pennsylvania Supreme Court's decision in *Kilmer v. Elexco Land Services, Inc.*[2] and the cases that applied it. In line with *Kilmer*, the District Court reasoned that the term "royalty" in an oil and gas lease was defined as free of production costs, but not post-production costs. The District Court's decision was not appealed.

[2] — Unfair Trade Practices and Consumer Protection Law.

[a] — *Commonwealth v. Chesapeake Energy Corporation*

Commonwealth v. Chesapeake Energy Corporation[3] involved claims by the Office of the Attorney General in the Commonwealth of Pennsylvania against oil and gas producers under the Pennsylvania Unfair Trade Practices and Consumer Protection Law ("UTPCPL"), at 73 Pa. Stat. Ann. §§ 201-1-201-9.3. The Pennsylvania Supreme Court held that the Office of Attorney General (OAG) could not bring such claims on behalf of private landowners relating to alleged conduct by oil and gas producers associated with the acquisition

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1 Coastal Forest Resources Co. v. Chevron USA, Inc., Civil Action No. 2:20-cv-1119 (W.D. Pa., filed July 24, 2020). (J. Stickman).

2 Kilmer v. Elexco Land Services, Inc., 990 A.3d 1147 (2010).

3 Commonwealth v. Chesapeake Energy Corporation 247 A.3d 934 (Pa. 2021).

of natural gas leases in Pennsylvania, because that conduct did not constitute "trade or commerce" as those terms were defined and understood under the UTPCPL. The Pennsylvania Supreme Court concluded that Commonwealth Court had erred in defining "trade and commerce" inconsistent with the statutory definitions and legislative intent of those terms within the UPTCPL, and that the statute did not provide a remedy for sellers against buyers.

[3] — Subsurface Trespass.

[a] — *Briggs v. Southwestern Energy Production Company.*

The opinion in *Briggs v. Southwestern Energy Production Company*[4] brought to a final conclusion a long-running case involving the legal viability of a subsurface trespass claim in Pennsylvania. The Pennsylvania Supreme Court reversed a Pennsylvania Superior Court opinion, holding that the rule of capture continues to apply in Pennsylvania, and may be relied upon by oil and gas producers that engage in hydraulic fracturing, at least in the absence of an actual, physical invasion of the property at issue. The Pennsylvania Supreme Court held that the superior court erred to the extent it either assumed hydraulic fracturing displaced the rule of capture, or that migration of natural gas across property lines necessarily was the result of an actual physical intrusion. On remand from the Pennsylvania Supreme Court, the superior court concluded that the landowner's complaint alleging subsurface trespass by hydraulic fracturing failed as a matter of law due to the lack of allegations or proof that any physical intrusion of the subject property had occurred. Specifically, the superior court cited the landowner's complaint, which did not allege that the gas producer had either drilled a wellbore across property lines or had intentionally propelled fracturing liquids across property lines.

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4 Briggs v. Southwestern Energy Production Company 2020 WL 7233111 (Pa. Super. 2020).

[4] — Abandonment and Availability of Equitable Remedies.

[a] —*SLT Holdings, LLC v. Mitch-Well Energy, Inc.*

In *SLT Holdings, LLC v. Mitch-Well Energy, Inc.*,[5] the Pennsylvania Supreme Court reversed an opinion from the Pennsylvania Superior Court, which affirmed a trial court's grant of summary judgment that an oil and gas lease was deemed abandoned. The case involved leases where wells were drilled and produced, but then no production in paying quantities occurred for more than a decade, and no delay rentals or other payments were issued pursuant to the leases. The landowner filed claims and sought summary judgment on equitable theories, including abandonment. The trial court granted summary judgment, and the Superior Court affirmed the grant of summary judgment based on the abandonment theory. The Supreme Court reversed and held it was error to rely on the equitable doctrine of abandonment before the trial court addressed if an adequate remedy at law existed through a contractual analysis of the lease provisions applicable to the dispute, including provisions addressing opportunity to cure, exclusive remedy for breach, and any retained rights of the lessee in the event of termination. The Supreme Court's decision was confined to addressing the error of the trial court in resolving equitable claims before determining if remedies existed under the contracts. The Supreme Court did not reach any decision on whether the leases had in fact expired under their own terms, but instead remanded for further consideration.

[5] — Natural Gas Storage Rights.

[a] — *Hughes v. UGI Storage Company.*

In the second appellate decision in *Hughes v. UGI Storage Company*,[6] the Pennsylvania Commonwealth Court affirmed that a natural gas company has the right to exercise the power of eminent domain to condemn properties within the buffer zone of a certificated underground natural gas storage field,

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5 SLT Holdings, LLC v. Mitch-Well Energy, Inc. 249 A.3d 888 (Pa. 2021),

6 Hughes v. UGI Storage Company, 243 A.3d 278 (2020), *accepted for discretionary review* at 256 A.3d 424, *vacated and remanded* by 2021 Pa. LEXIS 4071 (Nov. 29, 2021).

but only where the properties are included in the Federal Energy Regulatory Commission ("FERC") certificate. In this case, the properties at issue were not included within the scope of the natural gas storage company's relevant FERC certificate because it had not yet taken the necessary steps with FERC. Based on this record, the Commonwealth Court concluded that the natural gas storage company lacked the power to exercise its right to condemn the properties at issue. The Commonwealth Court noted that this situation could change after the natural gas storage company had included those properties within the scope of its certificate and made an unsuccessful offer to acquire those properties. The Commonwealth Court further distinguished between the "power" of eminent domain, and the "right" to exercise the power of eminent domain, holding that the natural gas company lacked the right to exercise its power of eminent domain as to properties outside of the FERC certificate.

Nevertheless, the Commonwealth Court upheld the trial court's grant of preliminary objections in favor the natural gas storage company, finding that the property owners failed to establish facts supporting deprivation of use or enjoyment of property as the immediate, necessary and unavoidable consequence of the exercise of the power to condemn, which it held were necessary elements to support a claim for a de facto taking. The Commonwealth Court concluded that the property owners' claim may lie in tort.

The Pennsylvania Supreme Court subsequently granted an application for discretionary review, framing the issue as "[D]oes the Commonwealth Court's holding eviscerate the well[-]recognized principles of a de facto taking claim under eminent domain jurisprudence by impermissibly imposing *du jure* taking elements on a de facto taking claim?" On November 29, 2021, the Pennsylvania Supreme Court reversed the Commonwealth Court's decision. The Pennsylvania Supreme Court held that because the natural gas storage company was vested with the power to condemn, the fact it did not have property-specific eminent domain power did not preclude an inverse condemnation claim. The Pennsylvania Supreme Court reasoned that this holding was consistent with the plain meaning of Pennsylvania's eminent domain code and most consistent with constitutional norms. The

Pennsylvania Supreme Court remanded for disposition of the trial court's alternative holding that the property owners had waived an entitlement to an evidentiary hearing on their claims.

[6] — Class Certification Pursuant to Fed. R. Civ. P. 23.

[a] — *Slamon v. Carrizo (Marcellus) LLC, et al.*

The decision in *Slamon v. Carrizo (Marcellus) LLC, et al*.,[7] issued by the United States District Court for the Middle District of Pennsylvania, certified two subclasses of royalty owners asserting express breach of contract claims for underpayment of royalties, while rejecting a broader third subclass of royalty owners purporting to bring claims for breach of implied duties under various oil and gas leases covering property in north central Pennsylvania, as well as rejecting certification for any injunctive or declaratory relief.

The case involved three defendant operators, who held interests at different times in the operative leases, and all of whom took in kind and marketed their own gas. Defendant Carrizo (Marcellus), LLC was the initial operator of the wells at issue, and Reliance Marcellus II, LLC was assigned a non-operating interest from Carrizo. It was alleged that Carrizo and Reliance sold their respective shares of the gas to DTE Energy Trading, Inc., at or near the wellheads. DTE gathered and transported gas to downstream locations and resold it to third party buyers. Plaintiffs challenged the operators' sales to DTE and contended that royalties paid to Plaintiffs and the classes contained improper deductions for post-production costs. During the course of the lawsuit, BKV Operating, LLC and BKV Chelsea, LLC acquired both Carrizo's and Reliance's interests, and Plaintiffs asserted similar claims against BKV.

Plaintiffs moved for class certification pursuant to Fed. R. Civ. P. 23, which the district court granted in part and denied in part. The district court granted certification under Fed. R. Civ. P. 23(a) and 23(b)(3) of two breach of contract claims against the defendants: (1) that defendants' breached a provision in certain leases that contained valuation language referencing

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7 Slamon v. Carrizo (Marcellus) LLC, et al., 2020 WL 2525961, 2020 US Dist. LEXIS 87149 (M.D. Pa. May 18, 2020).

a NYMEX price and (2) that defendants breached class leases containing express "no deductions" provisions. The Court rejected a third subclass based on an implied duty theory, holding that Plaintiffs had failed to establish the prerequisites of Rule 23(a). Specifically, the district court found that this proposed subclass failed the "commonality, typicality and ascertainability requirements" of Rule 23(a). The district court also rejected Plaintiffs' proposed classes for declaratory and injunctive relief pursuant to Fed. R. Civ. P. 23(b)(2), ruling that Plaintiffs had not met their burden for certification. The case has now preceded to cross motions for summary judgment on the merits.

§ 12.03. Ohio.

[1] — Title/Ownership of Oil and Gas Rights.

[a] —*West v. Bode.*

In *West v. Bode*,[8] the Ohio Supreme Court addressed the interplay of two different legislative enactments in Ohio relating to the title and ownership of mineral rights, including oil and gas rights. At issue was the Marketable Title Act ("MTA") and the Dormant Mineral Act ("DMA"), both of which the Court stated had the "express purpose … to simplify and facilitate land title transactions by allowing persons to rely on a record chain of title." The MTA "extinguishes property interests by operation of law after 40 years from the effective date of the root of title unless a saving event has occurred," and an interest extinguished under the MTA cannot be revived. The DMA, on the other hand, "does not extinguish interests by operation of law; interests are instead deemed abandoned and vested in the owner of the surface." In this case, the Ohio Supreme Court was tasked with determining whether there was an irreconcilable conflict between the MTA and DMA with respect to the application of oil and gas interests. In a 4-3 decision, the Ohio Supreme Court concluded there was no conflict and that both the MTA and DMA could apply to severed oil and gas interests. The Ohio Supreme Court majority held that while certain savings events existed under one statute and not another, this did not present an irreconcilable obstacle to the application

8 West v. Bode, 165 N.E.3d 298 (2020).

of either the MTA or DMA. Instead, it recognized that oil and gas interests could be extinguished (or abandoned) under one enactment and not another. The Court concluded that "the [MTA] and the [DMA] afford independent procedures, either of which may be used to effect the termination of a severed mineral interest, depending on the circumstances of the case and the time that has elapsed."

[b] — *Gerrity v. Chervenak.*

Gerrity v. Chervenak[9] addressed a continuing focus of litigation under the DMA regarding the reasonableness of an heirship search as part of the statutory abandonment process. Specifically, in order for a surface owner to effect the statutory abandonment process, they must comply with the requirements set forth in the DMA, including conducting a reasonably diligent search for the heirs of a severed mineral interest, and providing notice of the intent to declare the severed mineral interests abandoned. Where heirs cannot be reasonably identified or ascertained or are otherwise unknown, the DMA provides for notice by publication. A repeated issue that arose in cases is to what extent a "reasonably diligent" search includes sources beyond what is located in the recorded county records — including, for example, the use of online sources. In this case, the Ohio Supreme Court rejected a bright-line test and continued to endorse a case-by-case test of what constitutes a reasonably diligent search. In doing so, the Ohio Supreme Court also rejected any bright-line rule that use of the Internet or online sources as part of that search was required, and found that at least under the circumstances of this case, the use of the Internet or online sources was not required.

[c] — *Corso v. Miser.*

In *Corso v. Miser,*[10] the Seventh District Court of Appeals found that the term "minerals" as used in a 1949 deed was ambiguous as to whether it encompassed oil and gas rights, based on other language included within the deed itself. The court recognized that the term "minerals" could have

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9 Gerrity v. Chervenak, 166 N.E.3d 1230 (2020).

10 Corso v. Miser, 2020 Ohio 5293 (7th District 2020).

included oil and gas rights, but given the context and other language within the deed, it did not unambiguously encompass oil and gas rights in these specific circumstances. Having reached that conclusion, the court further held that the trial court did not err in evaluating parol evidence that oil and gas operations were prevalent in the area at the time of the deed's execution, and therefore, the trial court's conclusion that oil and gas was not reserved was affirmed.

[d] — *O'Brandonvich v. Hess Ohio Developments LLC.*

In *O'Brandonvich v. Hess Ohio Developments LLC*,[11] the Seventh District Court of Appeals upheld a trial court decision that found the language "other minerals" used in a 1940 reservation included oil and gas rights. The court relied on a presumption that the reference to "other minerals" in the deed included oil and gas interests, and started its analysis with the language of the deed to determine if it reflected that intent. The court concluded that none of the language in the deed was inconsistent with the development of oil and gas interests. The court framed its summary of Ohio law on the meaning of "other minerals" as "in Ohio, we start with the presumption that the general phrase may include oil and gas rights so long as the language can be reasonably seen to include these minerals in some way and other language in the deed does not exclude these minerals." The court also rejected the use of parol evidence to try to establish the parties may have intended a different result, because the language in the deed was not ambiguous.

[2] — Royalties and Post-Production Costs.

[a] — *Gateway Royalty, LLC v. Chesapeake Exploration.*

Gateway Royalty, LLC v. Chesapeake Exploration[12] involved a challenge to the calculation of oil and gas royalties. Chesapeake Exploration, LLC, the operator, sold gas at the wellhead to an affiliated marketing company, Chesapeake Energy Marketing, LCC ("CEMLLC"), which transported the

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11 O'Brandonvich v. Hess Ohio Developments LLC, 2021 Ohio 1287 (7th Dist. 2021).

12 Gateway Royalty, LLC v. Chesapeake Exploration, 2020 Ohio 1311 (7th Dist. 2020).

gas downstream and sold to other third party buyers. Plaintiffs asserted that Chesapeake's sale of the gas to CEMLLC at the wellhead did not constitute "marketing" the gas, and that therefore, their royalties should be based on downstream pricing, rather than the price at the wellhead. The Seventh District, reciting the *Merriam Webster* dictionary, found that the sale of the gas to CEMLLC was unambiguously marketing the gas, and therefore rejected this claim as a matter of law. The Court also rejected arguments that Chesapeake had improperly calculated royalties based on the netback price at the wellhead it received from CEMLLC, reciting several cases which upheld this methodology in similar situations and under similar lease terms.

[3] — Adverse Possession.

[a] — *Tomechko v. Garrett.*

Tomechko v. Garrett[13] involved a claim of adverse possession of a cotenant's undivided interests in oil and gas rights. The trial court found that shallow rights had been adversely possessed as a result of continued oil and gas production of those rights, but concluded that the adverse possession did not extend to the deeper oil and gas rights. The Seventh District Court of Appeals reversed, concluding that the shallow production and adverse possession of the shallow oil and gas rights extended to the deep rights, and the fact there was no deep production was not dispositive. Rather, it concluded that the adverse possession finding as to shallow rights extended to all strata, particularly given that the lease at issue for the shallow production authorized production from all strata. A discretionary appeal was denied by the Ohio Supreme Court.

[4] — Bankruptcy.

[a] — *Eric Petroleum v. Chesapeake Exploration, et al.*

Eric Petroleum v. Chesapeake Exploration, et al.[14] addressed the effect of the bankruptcy stay (applicable to Chesapeake Exploration, LLC) as to claims against co-defendants. This case asserted numerous breach of

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13 Tomechko v. Garrett, 2021 WL 1546068 (7th Dist. 2021).

14 Eric Petroleum v. Chesapeake Exploration, et al. (Columbiana Cty., 2020).

contract claims arising out of an asset sale agreement between Plaintiffs and Chesapeake. During the course of the litigation, by virtue of Chesapeake's bankruptcy, the claims against it were stayed. However, the Plaintiffs sought to pursue an injunction against co-defendants, who were other operators who acquired various interests from Chesapeake. The co-defendants sought a stay of claims against them, including the injunction claim, citing among other things, the overlap and connection of issues between the stayed claims against Chesapeake and the claims against the co-defendants. The trial court granted a stay as to the co-defendants, referencing Section 362(a) of the Bankruptcy Code. Specifically, the trial court found there was a sufficient identity of interest between Chesapeake and the other co-defendants, and also a potential impact on the bankruptcy estate if the action proceeded. Plaintiffs' appeal of the decision was denied as impermissible, because an order of stay is interlocutory, even when the trial court's stay is predicated on a bankruptcy stay.

§ 12.04. West Virginia.

[1] — Royalties and Post-Production Costs.

[a] —*Young v. Equinor USA Onshore Properties, Inc.*

In *Young v. Equinor USA Onshore Properties, Inc.*,[15] the Fourth Circuit Court of Appeals found that the specific language of the oil and gas lease at issue satisfied the West Virginia Supreme Court's presumption that a lessee bears post-production costs, concluding that the lease satisfied each of the three requirements such that the deduction of post-production costs was permissible. First, the Fourth Circuit held that the lease expressly provided that the lessor bears some part of the post-production costs. Second, the Fourth Circuit held that the lease identified with particularity the specific deductions the lessee intends to take from the lessor's royalty. Third, the Fourth Circuit found that the lease sufficiently indicated the method of

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15 Young v. Equinor USA Onshore Properties, Inc., 982 F.3d 201 (2020).

calculating the amount to be deducted from the royalty for such post-production costs.

[b] — *Corder v. Antero Resources Corporation.*

In *Corder v. Antero Resources Corporation,*[16] the Northern District of West Virginia held, in part, that certain leases containing a market enhancement clause did not meet the three-part test for deduction of post-production costs under West Virginia law, as discussed in *Young*. Specifically, the district court found the leases failed the second element of the test set forth in *Young*, because the "market enhancement clause," while enumerating types of post-production costs, does not "unambiguously identify the products from which those costs may be deducted." Concluding that the clause was ambiguous at best, the district court construed the clause against the lessee and entered partial summary judgment in favor of the plaintiffs on this issue.

[2] — Unitization.

[a] — *Ascent Resources- Marcellus LLC v. Huffman.*

Ascent Resources — Marcellus LLC v. Huffman[17] involved an oil and gas company's motion for a declaratory judgment that a 1980 oil and gas lease contained an implied covenant to pool or unitize the property for oil and gas development purposes, specifically, for the development of Marcellus Shale formation. The oil and gas company admitted the 1980 lease did not contain any express language regarding pooling or unitization. The 1980 lease continued to be held by shallow production. The oil and gas company argued that in order to economically develop the 1980 lease utilizing modern horizontal drilling techniques, the trial court should declare that pooling and unitization is reasonably necessary for further development and would place no undue burden on any other interest holder under the 1980 lease. The trial court denied the motion, concluding that the 1980 lease was not ambiguous, there was no language regarding pooling or unitization, it was not authorized

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16 Corder v. Antero Resources Corporation, 2021 WL 1912383 (N.D. W. Va. May 12, 2021).

17 Ascent Resources – Marcellus LLC v. Huffman, 851 S.E.2d 782 (2020).

to re-write the parties' contracts to provide rights that did not exist, and it would not imply new covenants into the unambiguous 1980 lease.

The West Virginia Supreme Court affirmed the trial court. It concluded that the 1980 lease was unambiguous, and that the trial court had correctly found that it could not alter or change the unambiguous contract. The West Virginia Supreme Court further held that the implied covenant sought by the oil and gas company "was neither contemplated nor bargained for when the lease was signed." While acknowledging that the record was clear that pooling and unitization would result in increased oil and gas production and result in more economical development, it noted that the trial court lacked the authority to provide the oil and gas company with rights that were not included in the 1980 lease.

§ 12.05. Other Jurisdictions.

[1] — Texas.

[a] — Royalties and Post-Production Costs.

- *Bluestone Nat. Res. II, LLC v. Randle*[18] addressed obligation to pay royalty on off-lease fuel.
- *Devon Energy Prod. Co., L.P. v. Sheppard*[19] demonstrates the mixed effect of "direct or indirect" post production deduction language in lease amendment.

[b] —Class Actions.

- *Seeligson v. Devon Energy Prod. Co., L.P.*[20] affirmed trial court's certification of royalty underpayment class.

[c] — Retained Acreage.

- *Endeavor Energy Res., L.P. v. Energen Res. Corp.*[21] After finding the clause at issue ambiguous, the court held it did not impose a special limitation.

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18 Bluestone Nat. Res. II, LLC v. Randle, 2021 WL 936175 (Tex. March 12, 2021).

19 Devon Energy Prod. Co., L.P. v. Sheppard, 2020 WL 6164467 (Tex. App.—Corpus Christi Oct. 22, 2020, pet. pending).

20 Seeligson v. Devon Energy Prod. Co., L.P., 804 Fed.App'x. 304 (5th Cir. 2020).

21 Endeavor Energy Res., L.P. v. Energen Res. Corp., 615 S.W.3d 144 (Tex. 2020).

[2] — Oklahoma.

[a] — Royalties and Post-Production Costs.

- *Cline v. Sunoco, Inc.*[22] Ruling following bench trial regarding claims by royalty owner class that Sunoco (as first purchaser) failed to pay statutory interest on payments made after the deadline in the Oklahoma Production Revenue Standards Act.
- *Slatten v. Range Res. Corp.*[23] Affirming the jury's finding that, in the context of a wellhead sale, the buyer's costs in the pricing formula were not deductions.

[b] — Class Actions.

- *Strack v. Continental Res., Inc.*[24] Finding class counsel's fee and class representative's incentive fee excessive.
- *Chieftain Royalty Co. v. BP Am. Prod. Co.*[25] Interpreting the scope of a release from prior class settlement and finding that the statutory interest claims asserted fell within the scope of that release.

[3] — North Dakota.

[a] — Royalties and Post-Production Costs.

- *Blasi v. Bruin E&P Partners, LLC*[26] Interpreting the common "free of cost, into the pipeline . . ." (take in kind) royalty provision to provide a wellhead royalty valuation location.

[b] — Lease Preservation.

- *Hess Bakken Inv. II v. Agribank*[27] Finding the term "actual drilling operations" was ambiguous.

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22 Cline v. Sunoco, Inc., 2020 WL 4748026 (E.D. Okla. Aug. 17, 2020).

23 Slatten v. Range Res. Corp., Case No. 118,171 (Okla Ct. Civ. App. March 3, 2021).

24 Strack v. Continental Res., Inc., 2021 WL 1540516 (Okla. 2021).

25 Chieftain Royalty Co. v. BP Am. Prod. Co., 2020 WL 1476419 (N.D. Okla. March 26, 2020).

26 Blasi v. Bruin E&P Partners, LLC, 2021 ND 86, 2021 WL 2006233 (N.D. 2021).

27 Hess Bakken Inv. II v. Agribank, 2020 ND 172, 942 N.W.2d 746 (N.D. 2020).

[c] — Duties to Overriding Royalty Interests.

- *Pitchblack Oil, LLC v. Hess Bakken Inv. II, LLC*[28] Finding there was no fiduciary duty to the ORRI owner and that the top leases did not trigger the parties' anti-washout provision.
- *Sunbehm Gas, Inc. v. Equinor Energy, LP*[29] Finding that ORRI payments did not require statutory interest pursuant to North Dakota's royalty payment statute.

[d] — Covenants.

- *Slawson Exploration Co., Inc. v. Nine Point Energy, LLC*[30] Finding that the promote obligation was not a covenant running with the land.

[4] — Kansas.

[a] — Royalties and Post-Production Costs.

- *Cooper Clark Found v. OXY USA Inc.*[31] Interpreting *Fawcett* to allow some marketable condition claims, but not others.
- *L. Ruth Fawcett Trust v. Oil Producers, Inc. of Kan.*[32] Applied the mandate rule to foreclose the plaintiffs' "new" theory on marketable condition.

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28 Pitchblack Oil, LLC v. Hess Bakken Inv. II, LLC , 949 F.3d 424 (8th Cir. 2020).

29 Sunbehm Gas, Inc. v. Equinor Energy, LP, 2020 WL 2025355 (D.N.D. April 27, 2020).

30 Slawson Exploration Co., Inc. v. Nine Point Energy, LLC, 966 F.3d 775 (8th Cir. 2020).

31 Cooper Clark Found v. OXY USA Inc., 58 Kan. App. 2d 335, 469 P.3d 1266 (2020).

32 L. Ruth Fawcett Trust v. Oil Producers, Inc. of Kan., 58 Kan. App. 2d 855, 475 P.3d 1268 (2020).

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