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FOUNDATION NEWS

ARTICLES

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TOPICAL READING

Rocky Mountain Mineral Law Foundation Journal

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Rocky Mountain Mineral Law Foundation Journal

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ROCKY MOUNTAIN MINERAL LAW FOUNDATION
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The Editorial Board, comprised of experienced natural resources law practitioners and academics, determines which articles should be printed, which law review articles should be reprinted, and which articles should be included in the Topical Reading list. Subscriptions to the semiannual *Journal* are $59 per calendar year and are automatically renewed. Annual Members receive the semiannual *Journal* electronically as a complimentary benefit of Annual Membership.

Preface

The Rocky Mountain Mineral Law Foundation Journal publishes original, short, practical, and scholarly articles, along with reprints of Foundation papers, law review articles, and other articles that are useful to the natural resources attorney. Published semiannually, the Journal emphasizes oil and gas, mining, public lands, water, and environmental law, as well as other related areas of natural resources law. The Journal was introduced in 2004 as the successor to the *Public Land & Resources Law Digest*.

We encourage you to submit articles for inclusion in the *Journal*. The Author Guidelines are included in this copy of the *Journal* and you may contact Executive Editor Jennifer Roulette at the Foundation for further information on publication.

Established in 1955 as a nonprofit Colorado corporation, the Rocky Mountain Mineral Law Foundation is a collaborative educational organization dedicated to the study of the legal systems and issues affecting natural resources law and other related areas. The Foundation trustees include representatives from law schools, bar associations, industry associations, and others in the land and legal community. The goals of the Foundation are to foster and encourage scholarly, yet practical study of the laws and regulations relating to domestic and international oil and gas, mining, water, public land management, land use, conservation, environmental protection, mineral financing, and other related disciplines.

The Foundation offers a variety of programs and services, including institutes, courses, workshops, and online distance learning; publication of treatises, books, forms and model forms, substantive newsletters, and other special studies; scholarships and research grants to law faculty and law students; and programs for natural resources law teachers.

Leading legal and land experts volunteer many hours in connection with Foundation institutes and publications and on the projects of various committees that carry out the Foundation's work. These volunteers have generously served the Foundation because of its reputation for continually striving to achieve the highest quality in its many projects.

Please consider becoming a member of the Rocky Mountain Mineral Law Foundation, joining a vibrant group of law firms, companies, government agencies, academic organizations, and others dedicated to supporting legal scholarship in the natural resources community.

Alex Ritchie
Executive Director

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Rocky Mountain Mineral Law Foundation Journal

Part I

Foundation News

Dedication to Richard H. Bate

Dear Friends of the Rocky Mountain Mineral Law Foundation,

It is with sadness that we share the news of the passing of Richard Bate on March 12, 2019, just a few weeks shy of his 88th birthday. His sons, Tom and Dave, whom he loved dearly, were with him when he passed. Richard is predeceased by his first wife, Elaine, and his second wife, Tana. For years many of his friends referred to him as Dick, until he met Tana, who insisted on calling him Richard.

Richard was the third Executive Director of the Foundation from 1967 through 1970, immediately preceding Dave Phillips. His sons can still recall stuffing envelopes for mailings as their first job and spending their vacations at institutes in the 1960s. After his time as Executive Director, he continued his active involvement with the Foundation as a volunteer and as an advisor, counsel, and good friend to Dave Phillips. It was apparently Richard's innovation to hold the annual institute at a family-friendly vacation spot, a tradition that continues to this day.

Richard served on the Editorial Board of the RMMLF Journal (formerly the Public Land and Resources Law Digest) for over 40 years, chairing the Board from 1981 to 1984. He also chaired the Site Selection Committee from 1977 to 1982, was the Colorado Bar Trustee from 1972 to 1976, was a Trustee-at-Large from 1976 to 1980, and became an honorary Trustee in 1994. Richard was also an active speaker and author. He wrote six annual and special institute papers, served as a revision author of the Law of Federal Oil and Gas Leases, and was a member of the Oil and Gas Short Course faculty for a number of years, chairing the course in 1990 and 1991.

In addition to his work for the Foundation, Richard taught mineral law classes at his alma mater, the University of Denver School of Law, chaired the Natural Resources and Energy Law Section of the Colorado Bar Association, and was the founder of the Denver Association of Oil and Gas Title Lawyers (DAOGTL), fondly referred to by its members as "Dogtail." Many of his colleagues still consider him the "Dean" of mineral title examination in Colorado. He was also innovative in recognizing that mineral estates could be severed and considered in many different ways. His former law partner, John Schultz, wrote a letter to Richard, stating:

> "I will always be grateful and cognizant of the fact that you, nearly alone among those in our industry, differentiated between coal bed methane gas and coal, and, in fact, wrote the opinion upon which I relied that really turned the industry upside down and contributed to the development of this resource as a separate and valuable product. You are not mentioned at any point in the opinion rendered by the United States Supreme Court in Amoco Production Co. v. Southern Ute Indian Tribe, 526 U.S. 865, 142 O. & G. R. 437 (1999), but that decision would never have been written had it not been for the pioneering which you did many years prior thereto. Speaking for myself and I'm sure for many others, I shall be forever grateful for the outcome in that case."

Sincerely,
Alex Ritchie & David P. Phillips

From the President

For decades, the mission of the Rocky Mountain Mineral Law Foundation has been to provide high quality educational programs and materials for professionals engaged in the natural resources industries. The Foundation's *Journal* promotes that mission by publishing timely, scholarly articles of interest to natural resources, mining, oil and gas, water, energy, and environmental lawyers, landmen, government officials, industry representatives, and students. The articles consist of original pieces as well as selected reprints from other sources. Whatever their origins, the *Journal*'s articles are consistently excellent and regularly address natural resources legal issues ranging from essential "nuts and bolts" basics to cutting-edge developments.

The *Journal*'s articles, when combined with the Foundation's ever-expanding collection of Annual and Special Institute papers, constitute a world-class collection of scholarly analysis and practical information on oil, gas, mining, energy, public lands, water, and environmental law. Most of these resources are available both in hard copy and word-searchable online databases.

If you are an author (or an aspiring author), please consider the *Journal* when seeking an outlet for your scholarship, as the *Journal* editorial board is always interested in considering quality manuscripts on relevant topics. Placement with the *Journal* will ensure that your work reaches a broad audience engaged in natural resources law.

The Foundation's publications, which span over sixty years, have earned well-deserved praise from practitioners and educators alike. In an era of nearly limitless (and often overwhelming) sources of information, you can confidently turn to the Foundation's materials, knowing that they represent the work product of experts in their respective disciplines.

William B. Prince, President

Volunteers Welcome
for
Committees, Boards, Reporters, and Update Authors

The Foundation is a nonprofit legal education organization with the sole purpose of serving its constituency, including lawyers, landmen, and others interested in the Foundation's programs and publications. Our constituency recommends the subjects and programs that the Foundation sponsors and the publications that it undertakes. Volunteers working through committees provide the underlying support for the Foundation's programs and publications. In addition to serving as speakers for our many institutes and short courses, volunteers serve on program committees for each Annual and Special Institute and a variety of special committees and boards. Volunteer opportunities include the American Law of Mining, 2d ed. (ALM 2d), Audit & Risk Management, Budget Review, Digital Technology, Financial Advisory, Forms, Gower Federal Services, Grants, International, Law of Federal Oil & Gas Leases (LFOGL), Membership, Publications, RMMLF Journal, Scholarships, Site Selection, and Special Institutes committees. Volunteers also serve as Update Authors for the ALM 2d and LFOGL, and as Reporters for our Mineral Law and Water Law Newsletters. Please let us know if you would be interested in serving on one or more committees or boards or as an update author for either of our two looseleaf treatises, ALM 2d or LFOGL, or as a state/regional newsletter reporter. Thanks.

— Alex Ritchie, Executive Director

Online Natural Resources Education

More than 145 presentations from Annual and Special Institutes are now available on the Foundation's online learning platform. Topics include oil and gas, mining, energy, environmental, international, public lands, Native American resources, landmen's issues, water, and ethics. These on-demand presentations and podcasts are professional video and audio recordings of our high-quality live programs. They can be accessed online 24/7, making them the easiest and most convenient method to receive natural resources legal education.

Learn from top-notch faculty at your convenience while fulfilling continuing education requirements with on-demand videos and podcasts accessible from any device with an Internet connection anywhere in the world. Train on your own time with premier individual natural resources CLE and CPE hours in an online video format, with synched PowerPoint slides (as available) included with each presentation. And when you learn with Rocky you can download an original paper by the presenter that will serve as a continuing reference. Contact info@rmmlf.org for CLE or CPE credit information on any particular presentation or for group discounts.

Visit our online legal education catalog regularly to see what's been added!

rmmlf.inreachce.com

RMMLF Upcoming Programs

Oil and Gas Mineral Title Examination
September 25-27, 2019 • Westminster, Colorado

International Oil & Gas Law, Contracts & Negotiations: Part 1 – From Concept to Discovery
September 23-27, 2019 • Houston, Texas

International Oil & Gas Law, Contracts & Negotiations: Part 2 – From Discovery to Decommissioning
September 30-October 4, 2019 • Houston, Texas

Petroleum Marketing Attorneys' Meeting
October 10-11, 2019 • Houston, Texas

Oil and Gas Law Short Course
October 21-25, 2019 • Westminster, Colorado

Federal Oil & Gas Leasing Short Course
October 21-24, 2019 • Westminster, Colorado

Endangered Species and Other Wildlife
October 29-30, 2019 • Denver, Colorado

Advanced Landman's Course
November 7-8, 2019 • Houston, Texas

Young Professionals Institute
March 2-3, 2020 • Denver, Colorado

Oil & Gas and Mine Financing
April 16-17, 2020 • Denver, Colorado

Public Land Law
May 7-8, 2020 • Santa Fe, New Mexico

66th Annual Rocky Mountain Mineral Law Institute
July 23-25, 2020 • Salt Lake City, Utah

International Mining Law Short Course
September 21-24, 2020 • Santiago, Chile

Federal Onshore Oil & Gas Pooling and Unitization
October 8-9, 2020 • Westminster, Colorado

Annual Water Law Institute
November 18-19, 2020 • San Diego, California

For additional information visit www.rmmlf.org
or contact the Foundation at:
phone (303) 321-8100 • fax (303) 321-7657 • info@rmmlf.org

Rocky Mountain Mineral Law Foundation

Publications

The Rocky Mountain Mineral Law Foundation (RMMLF) produces several publications on oil, gas, mining, energy, public land, water, and environmental law.

Proceedings of the Annual Institute is published every year and contains the papers presented by the speakers at that year's Annual Institute, edited and bound into a 900-page hardbound book including law-review quality articles covering oil and gas, mining, international mineral development, environmental, public lands, water, ethics, and landman topics.

Mineral Law Newsletter reporters representing 24 states and Canada report on judicial, legislative, and regulatory developments in mining and oil and gas law. Coverage includes federal courts and agencies, Congress, and environmental issues. State coverage includes Alabama, Alaska, Arizona, Arkansas, California, Colorado, Idaho, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming.

Water Law Newsletter reporters representing 26 states cover water law and water rights issues, including court decisions at federal, state, and local levels; state and federal regulatory agencies; and federal, state, and local statutory developments. State coverage includes Alaska, Arizona, California, Colorado, Idaho, Illinois, Indiana, Kansas, Michigan, Minnesota, Montana, Nebraska, New York, Ohio, Pennsylvania, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington, Wisconsin, and Wyoming. Federal water quality and reserved water rights are also covered.

Law of Federal Oil & Gas Leases serves as a primer and reference manual offering expert legal analysis and a practical approach to problems and questions on all matters of law related to federal oil and gas leases, including surface management requirements; exploration, drilling, producing, and operating regulations; rights-of-way; royalties; assignments and transfers of interests; options and rights to acquire; federal land records; and more. Updated annually by experts in their fields and edited by the Foundation, this treatise is available from LexisNexis.

Gower Federal Services contain governmental decisions and related indices developed by the Foundation that generally are not readily available. The different services include Oil & Gas, Mining, Outer Continental Shelf, Miscellaneous Land Decisions, and Royalty Valuation & Management. Periodic updates maintain the currency of each volume.

American Law of Mining, 2d Edition provides full coverage of all aspects of U.S. and Canadian mining law and related topics, including federal lands and mineral leases, state and Indian mineral interests, mining claims, environmental regulation, ancillary use and water rights, state and local taxation of minerals, and much more. Updated annually by experts in their fields and edited by the Foundation, this treatise is available from LexisNexis.

Landman's Legal Handbook, 5th Edition is an indispensable publication for all landmen. Coverage includes preparation of instruments; oil and gas leases; minerals other than oil and gas; examination of records for leasable and locatable minerals; curative work; oil and gas spacing, pooling and unitization; state requirements; and numerous checklists and forms.

Rocky Mountain Mineral Law Foundation

Publications

International Petroleum Transactions, 3d Edition introduces attorneys and negotiators to the basic concepts of international petroleum transactions.

Indigenous Rights in South America: FPIC and Other Key Issues for Natural Resource Development discusses indigenous rights legislation from the perspective of extractive industries, covering nine countries throughout South America, and also includes a chapter on the concept of free, prior and informed consent (FPIC), its use internationally, and its implementation in Canada.

Joint Operating Agreement: Applicability and Enforceability of Default Provisions covers rights and remedies in the event of default in various circumstances in common law and civil law jurisdictions, including analysis and comparison of international JOA model forms.

Mining Lease Handbook, 2d Edition contains a collection of mining lease clauses cross-referenced to enable the user to create a mining lease with a logical structure and consistent terminology.

An Introduction to Geology and Hard Rock Mining is an introduction to selected topics in geology and hard rock mining, and is written to give lawyers and landmen a source of basic technical information.

Treatise on Wyoming Water Law provides detailed coverage of existing Wyoming water law, with references to statutory provisions, regulations, and court decisions; discusses Wyoming's comprehensive administrative system for water; and considers the laws governing interstate rivers and the decisions establishing tribal and federal reserved water rights.

Nevada Law of Water Rights details the water rights of Nevada, a considerable part of which entails federal law applicable to other public land states and states where the prior appropriation doctrine prevails.

Energy Law and Policy for the 21st Century provides a concise examination of the fundamentals of energy law for the attorney or policy maker who is new to the field, with an emphasis on information rather than opinion or the latest regulations or court decisions, which can be easily obtained from other sources.

Forms (available electronically and in hard copy) produced by RMMLF include:

- Form 1–Rocky Mountain Unit Operating Agreement–Oil and Gas (Undivided Interest)
- Form 2–Rocky Mountain Unit Operating Agreement–Oil and Gas (Divided Interest)
- Form 3–Rocky Mountain Joint Operating Agreement–Oil and Gas
- Form 4–Rocky Mountain Mining Joint Operating Agreement
- Form 5A–Exploration, Development, and Mine Operating Agreement
- Form 5 LLC–Exploration, Development and Mining Limited Liability Company
- Form 6–Gas Balancing Agreement
- Form 7–Confidentiality and Nondisclosure Agreement

RMMLF Digital Library provides electronic access to the written materials from all RMMLF Annual and Special Institutes since 1955, comprising 120,000+ pages of text from more than 4,500 articles in 250 manuals and books. The materials are searchable by keyword, author, title, or year, and contain hypertext links to other Digital Library materials and cases, statutes, and administrative codes.

For more information visit
https://www.rmmlf.org/publications

Rocky Mountain Mineral Law Foundation

Grants Program

The Rocky Mountain Mineral Law Foundation (RMMLF) established the Grants Program in 1976 to promote scholarship, research, writing, teaching, and the study of mineral resources law and related fields at law schools. In 2017 the Grants Program was expanded to include (1) innovative new projects or proposals in the fields of mining law, oil and gas law, energy law, water law, public land law, and related legal areas; and (2) a Visiting Lecture Program for Constituent Law Schools (CLS) of the Foundation. To date, 269 grants have been authorized, totaling over $760,000.

Applications are evaluated by the RMMLF Grants Committee, with preference given to the Foundation's CLS. A grant-supported project should result in a clear, tangible outcome with widespread utility and long-term value. Examples of eligible projects include:

- Preparation of teaching materials
- Research expenses incurred by faculty and supervised law students
- Printing or publication expenses for law school seminars, short courses, or symposia
- Start-up funding for new educational programs, classes, or conferences

The Grants Program will not support recurring projects or programs; projects that involve political or positional advocacy or litigation; or scholarships, fellowships, or visiting professorships.

Faculty honoraria and travel/attendance expenses are generally not within the scope of RMMLF grants, except that CLS may apply for funding under the Visiting Lecture Program to reimburse travel costs for a CLS professor or a member-practitioner to travel to another CLS to teach a law school class or provide a scholarly lecture to the law school community.

No special application form is required. Please submit a cover letter and proposal with the following required information:

- Your contact details and qualifications to undertake the project;
- A brief narrative describing the Project's:
  - Objectives and duration,
  - Implementation,
  - Intended results and impact;
- A budget of the total anticipated expenses; and
- The amount and intended use, broken out by budget line item or specific category, of grant funds you are requesting from the Foundation.

The application (Cover Letter and Project Description) should be no more than four pages. You may also attach your organization's general brochure and other information you feel would help the Committee better understand your proposal.

Applications and requests for information regarding the Grants Program should be sent to grants@rmmlf.org. Or visit our website at https://www.rmmlf.org/professors-and-students/grants.

To apply or request further information, please contact:

Rocky Mountain Mineral Law Foundation
9191 Sheridan Blvd., Suite 203 • Westminster, CO 80031
(303) 321-8100, ext 107 • grants@rmmlf.org

Rocky Mountain Mineral Law Foundation

Grants Program Awards Announcement

The Rocky Mountain Mineral Law Foundation is pleased to have awarded 3 grants since January 1, 2019:

- **Lewis & Clark Law School, Professor Michael Blumm —** Research assistance for book on Sacrificing the Salmon: A Legal and Policy History of the Decline of Columbia Basin Salmon

- **University of Arizona Global Mining Law Center, Director John Lacy —** Support for video-recorded interviews with mining attorneys for online mining law instruction

- **University of Kansas School of Law, Professor Uma Outka —** Visiting Lectures on natural resource law issues

Grant applications are accepted on a continuing basis and are generally evaluated quarterly by the RMMLF Grants Committee, with preference given to Constituent Law Schools of the Foundation. To support and learn more about Foundation Grants and other programs, please email grants@rmmlf.org or visit https://www.rmmlf.org/professors-and-students/grants.

Rocky Mountain Mineral Law Foundation

Scholarship Programs

The Rocky Mountain Mineral Law Foundation has three Scholarship Programs to encourage well-qualified law students who have the potential to make significant contributions to scholarship in mineral resources law and related areas.

These are the Joe Rudd (JR) Scholarships, established in 1980 in honor of a prominent natural resources attorney in Alaska; the RMMLF Scholarships, established in 1993 and including the David P. Phillips Scholarship established in 2012; and the Frances Hartogh Diversity Outreach (FHDOS) Scholarships, established in 2019. To date, 585 scholarships have been awarded amounting to over $3.1 million.

Eligibility — A law student enrolled full time at one of the Foundation's Constituent Law Schools and who can demonstrate a commitment to the study of mineral resources law and related areas is eligible to apply for these scholarships.

Amount of Scholarships — Scholarships may cover partial or full tuition. Recent awards ranged from $3,600 to $13,000 for a semester. These tuition scholarships must be used at, and will be paid directly to, one of the Constituent Law Schools.

Application Process — The application period typically begins in January, with deadlines of February 28 and March 15 for JD and LLM applicants, respectively.

The Application Form, which contains information regarding the process and requirements, is posted on our website at www.rmmlf.org under the Professors and Students tab. Please visit our website regularly for updates.

Applications are evaluated by the RMMLF and JR Scholarship Committees according to an established set of criteria, which include:

- Potential to make a significant contribution to the field of mineral resources law and related areas
- Academic ability
- Leadership ability
- Year in law school
- Financial need

RMMLF Constituent Law Schools

University of Alberta
University of Arizona
Arizona State University
Brigham Young University
University of Calgary
University of California-Davis
University of Colorado
Creighton University
University of Denver
Florida State University
Gonzaga University
University of Houston
University of Idaho
University of Kansas
Lewis and Clark Law School
Louisiana State University
University of Montana
University of Nebraska
University of Nevada-Las Vegas
University of New Mexico
University of North Dakota
University of Oklahoma
University of Oregon
University of the Pacific-McGeorge
University of South Dakota
Southern Methodist University
Texas A&M University
Texas Tech University
University of Texas
University of Tulsa
University of Utah
Washburn University
University of Wyoming

Rocky Mountain Mineral Law Foundation

2019-2020 Joe Rudd, RMMLF and Francis Hartogh Diversity Outreach Scholarships Awards Announcement

The Rocky Mountain Mineral Law Foundation (RMMLF) is pleased to announce the recipients of the 2019-2020 Joe Rudd; RMMLF, including the David P. Phillips Scholarship; and Frances Hartogh Diversity Outreach Scholarships.

Thirty new Foundation scholars were named this year:

Joe Rudd Scholarship Awards

Madeline Bugh, University of Oklahoma
Sydney Donovan, University of Denver
Bret Huffaker, University of Utah

Francis Hartogh Diversity Outreach Scholarship Awards

Lanna Allen, Washburn University
Morgan Johnson, University of New Mexico

David P. Phillips Scholarship Award

Noah Stanton, University of Colorado

RMMLF Scholarship Awards

Lanna Allen, Washburn University
Chinonso Anozie, Southern Methodist University
Madeline Bugh, University of Oklahoma
Cecilia Cahuayme, University of Texas
Scott Carriere, University of Calgary
Amanda Cerisano, University of Alberta
Sydney Donovan, University of Denver
Elisa Genuis, University of Alberta
Blake Gerow, University of Tulsa
Marlena Gutierrez, Southern Methodist University
Alex Hamilton, University of Colorado
Danielle Hartley, University of Denver
Bret Huffaker, University of Utah
Deborah Huveldt, Florida State University
Viktoriia Ishchenko, University of Texas
Morgan Johnson, University of New Mexico
Christina Jovanovic, Arizona State University
Patrick Kent, University of Wyoming
Kelsee Kephart, University of Oklahoma
Joseph Kmetz, University of Denver
Nicolas Lindal, University of Alberta
Henry Lindpere, University of Arizona
Pedro Llado Camarillo, University of Texas
William Thomas Machell, University of Calgary
Elias Medina, Louisiana State University
Kenryo Mizutani, University of Calgary
Joseph Reynolds, Texas Tech University
Robert Rozell, University of Tulsa
Daniel Tavera, University of Oklahoma

The Foundation congratulates the awardees and thanks all of the applicants for their interest and efforts!

Law students enrolled full time at one of the Foundation's Constituent Law Schools and who can demonstrate a commitment to the study of natural resources law are eligible to apply. Academic and leadership ability, as well as financial need, are considered. Applications are evaluated by the Foundation's Scholarships Committee consisting of dedicated volunteer attorneys. The application deadline is February 28 (for JD students) and March 15 (for LLM students). If you would like to support and/or learn more about the Foundation and its programs, please contact:

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9191 Sheridan Blvd., Suite 203
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(303) 321-8100 • fax (303) 321-7657
info@rmmlf.org • www.rmmlf.org

Rocky Mountain Mineral Law Foundation

Law School Student Programs

RMMLF Law Student Programs aim to generate interest among students from the Foundation's Constituent Law Schools (CLS) in mineral law and related areas, increase their awareness about the Foundation's specialized educational opportunities, and encourage their involvement in the Foundation's educational programs. For further information, please email info@rmmlf.org.

Student Attendance Programs

With the active engagement of the Foundation's CLS Trustees, these programs support attendance by deserving students at RMMLF programs. Subject to space and funding availability, Foundation support can include waived registration fees, course materials, and reimbursement of pre-approved expenses for transportation and accommodations.

Scholarship Recipient Attendance Program — RMMLF, Joe Rudd, and Frances Hartogh Diversity Outreach scholarship awardees are eligible to attend an annual or special institute following notification of their award.

CLS Law Student Attendance Program — The Foundation can make available up to $3,000 per calendar year for each of the Foundation's CLS to support students' attendance at Foundation programs.

The Foundation may, in limited cases, also provide support for deserving students from law schools other than Foundation CLS to attend RMMLF institutes and select short courses.

Student Networking Program

This program supports collaborative events and activities in the CLS among student organizations, trustees, law professors, local law firms, and other Foundation members. These events are intended to foster education, generate interest in mineral law and related areas, and increase awareness about, and involvement with, the Foundation's educational programs and opportunities. This program may also support student chapters or affiliates.

RMMLF Constituent Law Schools

University of Alberta
University of Arizona
Arizona State University
Brigham Young University
University of Calgary
University of California-Davis
University of Colorado
Creighton University
University of Denver
Florida State University
Gonzaga University
University of Houston
University of Idaho
University of Kansas
Lewis and Clark Law School
Louisiana State University
University of Montana
University of Nebraska
University of Nevada-Las Vegas
University of New Mexico
University of North Dakota
University of Oklahoma
University of Oregon
University of the Pacific-McGeorge
University of South Dakota
Southern Methodist University
Texas A&M University
Texas Tech University
University of Texas
University of Tulsa
University of Utah
Washburn University
University of Wyoming

For further information, please email info@rmmlf.org

About the Rocky Mountain Mineral Law Foundation

The Trustees of the Rocky Mountain Mineral Law Foundation are pleased to announce the election of the following Officers, Board Members-at-Large, and new Trustees. With the exception of the accession from Vice President to President, which is covered under the Bylaws, Trustees-at-Large are elected annually as a complement to those appointed by the Foundation's Constituent Law Schools, Bar Associations, and Oil and Gas and Mining Associations. Past Presidents become lifetime Trustees following their service, and Honorary Trustees periodically are appointed.

Rocky Mountain Mineral Law Foundation Constituent Organizations

Law Schools

University of Alberta
University of Arizona
Arizona State University
Brigham Young University
University of Calgary
University of California-Davis
University of Colorado
Creighton University
University of Denver
Florida State University
Gonzaga University
University of Houston
University of Idaho
University of Kansas
Lewis and Clark Law School
Louisiana State University
University of Montana
University of Nebraska
University of Nevada-Las Vegas
University of New Mexico
University of North Dakota
University of Oklahoma
University of Oregon
University of the Pacific-McGeorge
University of South Dakota
Southern Methodist University
Texas A&M University
Texas Tech University
University of Texas
University of Tulsa
University of Utah
Washburn University
University of Wyoming

Bar Associations

Alaska Bar Assn.
American Bar Assn.
State Bar of Arizona
Colorado Bar Assn.
Idaho State Bar
State Bar of Montana
Nebraska State Bar Assn.
State Bar of Nevada
State Bar of New Mexico
State Bar of South Dakota
State Bar of Texas
Utah State Bar
Wyoming State Bar

Mining Associations

Alaska Miners Association
American Exploration & Mining Assn.
Arizona Mining Assn.
Colorado Mining Assn.
Idaho Mining Assn.
National Mining Assn.
Nevada Landman's Assn.
Nevada Mining Assn.
New Mexico Mining Assn.
Rocky Mtn. Assn. of Mineral Ldmn.
Utah Mining Assn.

Oil & Gas Associations

American Assn. of Professional Ldmn.
American Petroleum Institute
Assn. of Intl. Petroleum Negotiators
Denver Assn. of Petroleum Ldmn.
Indep. Petroleum Assn. of America
Indep. Petroleum Assn. of New Mexico
New Mexico Oil & Gas Assn.
Western Energy Alliance

Author Guidelines for *Rocky Mountain Mineral Law Foundation Journal*

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Submission

Please submit the following to the Foundation:

- **Author Information:** Author's name; company or firm affiliation and title; and contact information, including email address.
- **Manuscript:** An electronic version of the article in MS Word.
- **Disclosure Information (if applicable):** Any involvement of the author, or anyone in the author's company or firm, in litigation or legislation discussed in an article must be disclosed. Such involvement must also be noted in the footnotes to the article.
- **No Guarantee of Publication:** There is no guarantee that submitted articles will be published.

Editorial Process

Every article submitted for publication in the *RMMLF Journal* will be reviewed by the *Journal*'s Editorial Board. The editorial process generally follows these steps:

1. Articles submitted should be ready for publication, and must conform to the Publication Standards set out below. Accuracy of both substantive content and citations is the sole responsibility of the author.
2. The Foundation may further edit the approved article to conform to the *RMMLF Journal*'s editorial style standards, but substantive editing will not be performed.
3. If there are any changes from the original article submitted, the author will be provided the edited manuscript for review and approval before publication. If the revision is not acceptable, the author should inform the Foundation immediately. The article will be published only if a mutual agreement is reached.
4. A standard license agreement must be executed by each author and returned to the Foundation. The license agreement allows the *RMMLF Journal* to publish and distribute the author's work in both print and electronic media. The author retains the copyright.

Publication Standards

- **Content/Tone:** Articles should be scholarly, practical, useful, and oriented to natural resources practitioners specializing in oil and gas, mining, public lands, water, and/or related environmental law. If an opinion is expressed, it should be made clear that it is the author's, and should be based on cited authority. Writing about proposed legislation is not the focus of the *Journal*.
- **Citations:** Citations should appear in numbered footnotes, not in the text of the article. Long string cites generally are not used. Cites to electronic databases (such as LexisNexis or Westlaw) should be avoided; if no other source is available for a case, provide the court, docket number, month, and date of the decision. Titles of books and periodicals should be italicized in upper and lower case, and titles of articles should be in quotes. Book citations should include the publisher's name, city, state, and year of publication. For other citations, the *RMMLF Journal* generally follows *The Bluebook: A Uniform System of Citation*.
- **Quotations:** Lengthy quotations should be used only if necessary. Long quotations or excerpts of 50 words or more should be indented, without quotation marks.
- **Format and Length:** Manuscript length should not exceed 15,000 words, and article titles should be no longer than twelve (12) words. Subheadings are encouraged, and should be a maximum of eight (8) words.

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Part II

Articles

CERCLA Enforcement: Recent Key Developments and Perspectives

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Synopsis

I. Introduction*

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") is not your typical environmental enforcement statute. No wrongdoing or current violation of any law or regulation is required to trigger its application. In fact, outside an emergency spill situation, the liability trigger typically is a historical environmental condition that environmental regulators and, typically, neighbors and other stakeholders deem an unacceptable risk to human health and the environment. Whether the facility complied with then-applicable environmental requirements is, relative to the liability determination, irrelevant. That, plus a liability scheme that is generally strict, and joint and several, tips CERCLA into its own special class among the environmental enforcement statutes. Notwithstanding its breadth and scope, the statute has survived multiple constitutional challenges.

With the stakes often quite high, CERCLA caselaw has evolved thematically over time to address the four key issues posed by CERCLA's draconian liability

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scheme: (1) challenges to the listing of a site on the National Priorities List ("NPL"), where listing virtually ensures multiple costly legal and technical battles; (2) the so-called "pre-enforcement review bar" in CERCLA § 113(h) that, effectively, cuts off any rights to appeal an enforcement order; (3) who can be held jointly and severally liable for these expensive CERCLA cleanups in the first instance; and (4) how the cleanup costs should be divided among the liable parties thereafter.

Given the high stakes, in terms of both liability and costs, particularly at historic mining sites, much of "the action," so to speak, in CERCLA legal practice involves often-protracted settlement negotiations leading to either administrative orders on consent ("AOCs") or judicially approved consent decrees ("Consent Decrees"). In this context, the focus shifts from whether a party is liable at all, to the question of what the party is liable for. Then the key additional question is whether this alleged liability is going to be resolved with the performance of work, the payment of money, or both, as that directly impacts the structure and the complexity of both the settlement itself and the settlement negotiations.

For CERCLA settlements, precedent and outcomes are driven most immediately by a confusing array of so-called "model" agreements and orders, plus non-binding guidance documents, that define the key, "model" terms that the United States, and particularly the U.S. Environmental Protection Agency ("EPA") and the U.S. Department of Justice ("DOJ"), deem legally acceptable in a CERCLA settlement. In addition, in a work performance settlement, the National Contingency Plan ("NCP"), along with many additional, non-binding guidance documents, drive the technical discussions, often on a parallel track, to define the work to be performed consistent with CERCLA and NCP mandates.

CERCLA caselaw, which, along with the statute, provides the backdrop for those settlement discussions, is dynamic. There are always new challenges and claims, some strong, some not. This paper highlights certain recent important decisions from the courts on the topics noted above: challenges to NPL listings, defining the reach and limits of the pre-enforcement review bar, CERCLA owner liability and particularly the United States' CERCLA liability based on its status as a landowner, and liability apportionment and allocation. The paper also addresses the federal government's key model agreements for CERCLA settlements and highlights certain significant and innovative settlements that found an acceptable balance between the constraints of the "boilerplate" language of the specific model agreements and the issues and complexities each site presents. The recommendations of the Trump Administration's Superfund Task Force could significantly impact CERCLA settlements, although as discussed below, the recommended improvements may not ultimately provide potentially responsible parties ("PRPs") at CERCLA sites with much relief. Finally, the paper will address recent regulatory and caselaw developments related to Resource Conservation and Recovery Act ("RCRA") § D on coal combustion residuals.

II. Recent Key Caselaw

A. NPL Challenges

An NPL listing in and of itself has no enforcement consequence.[1] However, it does foreshadow and virtually assures the costly legal and technical battles that an NPL listing seems to invariably engender, in addition to the business and financial disclosures implications.[2] The "box score" on challenges to NPL listings is generally not favorable to PRPs, especially at mining sites with water quality impacts. The remedial purpose of the statute, the site scoring system, and if needed, a dose of *Chevron* deference, are an often-lethal combination for NPL listing challenges,[3] which are heard on the administrative record and exclusively in the D.C. Circuit Court of Appeals.[4] But there also are a few exceptions to that rule. Two recent decisions reinforce both outcomes.

In *Sunnyside Gold Corp. v. Environmental Protection Agency*, the court affirmed EPA's NPL listing of the Bonita Peak Mining District ("BPMD"), including the Sunnyside Mine.[5] Following a now infamous, accidental discharge of acid mine drainage from the Sunnyside Mine into the Animas River in 2015,[6] the EPA evaluated the BPMD for listing on the NPL, pursuant to CERCLA's Hazard Ranking System ("HRS"), which is part of the NCP. The HRS is the principal mechanism the EPA uses to evaluate sites for listing on the NPL.[7] EPA defined the BPMD for HRS scoring purposes as "the result of a comingled release of hazardous substances into surface water due to … mining-related activities in three converging drainages … that converge in the headwaters of the Animas

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[1] The list of sites on the NPL is located at 40 C.F.R. pt. 300, Appendix B.

[2] *See, e.g.*, Carus Chem. v. EPA, 395 F.3d 434, 437 (D.C. Cir. 2005) (although placement on the NPL does not automatically make a party liable for cleanup costs, it "can have significant adverse consequences for the owner of a listed property," including, for example, costs in business reputation, property value, and increased probability of remediation). The SEC has shown increased interest in environmental issues since the passage of the Sarbanes-Oxley Act in 2002, and the changes enacted through Sarbanes-Oxley "directly affect the recognition, measurement and disclosure of liabilities associated with environmental cleanups, natural resource damages, asset retirement obligations, toxic tort claims, and regulatory fines and penalties." C. Gregory Rogers, "Environmental Financial Disclosure Rules and Their Impact on Brownfields Transactions," ABA Environment, Energy, and Resources Law Summit, 16th Section Fall Meeting (2008).

[3] *See, e.g.*, Eagle-Picher Indus., Inc. v. EPA, 759 F.2d 922 (D.C. Cir. 1985) (upholding EPA's addition of certain mining sites to the NPL); Eagle-Picher Indus., Inc. v. EPA, 822 F.2d 132 (D.C. Cir. 1987) (concluding that EPA's listing of five sites to the NPL was reasonable and lawful).

[4] 42 U.S.C. § 9613(a) ("Review of any regulation promulgated under this chapter may be had upon application by any interested person only in the Circuit Court of Appeals of the United States for the District of Columbia. Any such application shall be made within ninety days from the date of promulgation of such regulations."); Wash. State Dep't of Transp. v. EPA, 917 F.2d 1309, 1311 (D.C. Cir. 1990) ("The designation of a hazardous waste site on the NPL is considered rulemaking subject to judicial review under 42 U.S.C. § 9613(a) . . . .").

[5] Sunnyside Gold Corp. v. EPA, 715 F. App'x 7 (D.C. Cir. 2018).

[6] The incident garnered substantial regional, national and international media coverage. *See, e.g.*, https://www.theguardian.com/us-news/gallery/2015/aug/10/colorado-animas-river-colorado-toxic-waste; https://www.smithsonianmag.com/smart-news/whats-next-animas-river-180956217/; http://www.cpr.org/news/newsbeat/epa-admits-it-triggered-million-gallon-mine-waste-release-animas-river.

[7] 40 C.F.R. pt. 300, Appendix A.

River."[8] The EPA scored 19 sources of contamination within the BPMD, and noted, but did not score, 29 other sources. The Sunnyside Mine was not scored.[9]

Sunnyside Gold challenged EPA's inclusion of its mine on the NPL, arguing that EPA "erred in creating a site comprising both scored and unscored sources … [and that] each individual source was in fact a separate 'site,' and the EPA was required to score all of them before adding the BPMD as a whole to the NPL."[10] The court rejected this argument because the HRS definition of "site" is broad enough to include an "[a]rea[] [i.e., a 'source'] where a hazardous substance has been deposited, stored, disposed, or placed, or has otherwise come to be located," and "may include multiple sources and may include the area between sources."[11] Based on this distinction between site and source, the court found that the EPA properly scored the BPMD, and accordingly did not err when it listed the BPMD on the NPL. "The BPMD is a site composed of the 19 scored sources and the areas 'between' them, as the HRS explicitly permits; Sunnyside's mine falls into the category of an 'area between sources' and therefore did not need to be scored."[12]

In contrast, the D.C. Circuit vacated EPA's 2016 NPL listing of the West Vermont Drinking Water Contamination Site in Indiana,[13] holding that the listing was arbitrary and capricious because EPA "'entirely failed to consider an important aspect of the problem' by failing to address evidence that runs counter to the agency's decision . . . ."[14] At issue was a groundwater contamination plume extending beneath a residential and commercial area in Indianapolis. EPA contended that the contamination emanated from two distinct facilities, one impacting a shallower aquifer and the other impacting a deeper water-bearing zone.[15] In determining the site's HRS score for NPL listing, EPA treated the two aquifer zones as a single hydrologic unit. Had the aquifers been treated separately, the final HRS score would not have qualified the site for listing on the NPL.[16] The studies EPA relied on included three diagrams that appeared to contradict EPA's position because they showed there were layers of sediment that separated and served as a confining layer between the aquifers.[17] The court found EPA ignored evidence that was contrary to its conclusion, and that it "was arbitrary and capricious for EPA to rely on portions of studies in the record that support its position, while ignoring cross sections in those studies that do not."[18] As a result,

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[8] *Sunnyside*, 715 F. App'x at 8.

[9] *Id*.

[10] *Id*. at 8–9.

[11] *Id*. at 9 (quoting 40 C.F.R. pt. 300, Appendix A, § 1.1 (HRS) (first and second alterations in original)).

[12] *Id*.

[13] EPA issued its final rule adding the West Vermont Site to the NPL, along with nine other sites, on September 9, 2016. 81 Fed. Reg. 62,397 (Sept. 9, 2016).

[14] Genuine Parts Co. v. EPA, 890 F.3d 304, 307 (D.C. Cir. 2018) (quoting Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983)).

[15] *Id*.

[16] *Id*.

[17] *Id*. at 313.

[18] *Id*.

the court vacated EPA's addition of the West Vermont Drinking Water Contamination Site to the NPL.[19]

B. Pre-Enforcement Review Bar

CERCLA § 113(h) includes the statute's "pre-enforcement review bar" and provides:

> No federal court shall have jurisdiction … to review any challenges to removal or remedial action selected under section 9604 of this title, or to review any order issued under section 9606(a) of this title, in any action except one of the following:
>
> (1) An action under section 9607 to recover response costs or damages or for contribution.
>
> (2) An action to enforce an order issued under section 9606(a) of this title or to recover a penalty for violation of such order.
>
> (3) An action for reimbursement under section 9606(b)(2) of this title.
>
> (4) An action under section 9659 of this title (relating to citizen suits) alleging that the removal or remedial action taken under section 9604 of this title or secured under section 9606 of this title was in violation of any requirement of this chapter. Such an action may not be brought with regard to a removal where a remedial action is to be undertaken at the site.
>
> (5) An action under section 9606 of this title in which the United States has moved to compel a remedial action.[20]

The purpose of the pre-enforcement review bar is to preclude challenges to EPA cleanup decisions and activities that would delay CERCLA cleanups and otherwise cause irreparable harm to human health and the environment.[21] The practical effect of the bar is most stark in the context of EPA's issuance of a unilateral order, where, absent an enforcement action, pursuant to Subsection 113(h)(2), a PRP has no right to challenge the order as arbitrary and capricious except in the unenviable context of an enforcement action for non-compliance with the order.[22] Instead, the PRP must implement the unilateral order, at whatever the cost, and then seek whatever recourse it can after the fact.[23]

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[19] *Id*.

[20] 42 U.S.C. § 9613(h); *see also What Claims Fall Within Limitation Imposed by Section 113(h) of CERCLA*, 116 A.L.R. Fed. 69 (1993).

[21] The Senate Judiciary Committee Report stated that § 9613(h) barred pre-enforcement review because such review

> would be a significant obstacle to the implementation of response actions and the use of administrative orders. Pre-enforcement review would lead to considerable delay in providing cleanups, would increase response costs, and would discourage settlement and voluntary cleanups.

S. Rep. No. 11, 99th Cong., 1st Sess. 58 (1985).

[22] 42 U.S.C. § 9613(h)(2).

[23] *See, e.g.*, United States v. NCR Corp., 2012 WL 1490200 (E.D. Wis. 2012). If a PRP receives a unilateral order from EPA, it may comply and, after completing the cleanup, seek reimbursement from EPA. 42 U.S.C. § 9606(b)(2)(A). If EPA refuses reimbursement, the PRP may sue to recover its costs on the grounds that (1) it was not liable for the cleanup, *id.* § 9606(b)(2)(B)(C); or (2) it was liable, but

The controversial nature of the pre-enforcement bar has garnered significant legal commentary.[24] However draconian, the courts have readily rejected challenges to the constitutionality of the bar.[25] Recent cases continue to invoke the pre-enforcement review bar in cases that could impinge on EPA's CERCLA authority.[26] Despite the broad scope of the pre-enforcement review bar, certain claims are not barred, and the manner in which the claims are pled may be important to the outcome. For example, claims that the government must pay private party medical monitoring costs have been found not to constitute challenges to any federal removal or remedial action, and thus are not barred by Section 113(h).[27] A Petition for Writ of Certiorari was recently filed to a 2017 Montana Supreme Court decision in *Atlantic Richfield Co. v. Christian*, where the primacy of the pre-enforcement review bar over private party, state law claims for so-called "restoration damages" is directly at issue.[28]

EPA's selected response action was "arbitrary and capricious or ... otherwise not in accordance with law," *id.* § 9606(b)(2)(D). If the PRP does not comply with the unilateral order, EPA may sue the PRP to enforce or may clean the site itself and sue for cleanup costs. If the court determines that the PRP "willfully" and "without sufficient cause" failed or refused to comply with the unilateral order, the court may impose a penalty, which is currently up to $53,907 per day. *Id.* § 9606(b)(1); EPA Memorandum, *Revised Penalty Matrix for CERCLA § 106(b)(1) Civil Penalty Policy* (Sept. 6, 2016) (setting forth current daily penalty). The court may also impose treble damages. 42 U.S.C. § 9607(c)(3) (Any person who is liable for a release or threat of release of a hazardous substance and "fails without sufficient cause" to comply with a unilateral order, "may be liable to the United States for punitive damages in an amount at least equal to, and not more than three times, the amount of any costs incurred by the Fund as a result of such failure to take proper action.").

[24] *See, e.g.*, Michael P. Healy, "The Effectiveness and Fairness of Superfund's Judicial Review Preclusion Provision," 15 *Va. Envtl. L.J.* 271, 307 (1996); Brian Patrick Murphy, "CERCLA's Timing of Review Provision: A Statutory Solution to the Problem of Irreparable Harm to Health and the Environment," 11 *Fordham Envtl. L.J.* 587, 590 (2000).

[25] General Electric spent nearly a decade litigating this issue. In 2004, the D.C. Circuit reversed the District Court's decision to dismiss GE's challenge to the Section 113(h) pre-enforcement review bar, and held that the court had subject matter jurisdiction to determine whether Section 113(h) is constitutional. Gen. Elec. Co. v. EPA, 360 F.3d 188 (D.C. Cir. 2004). Six years later, the issue of Section 113(h)'s constitutionality was back before the D.C. Circuit Court of Appeals. The court held that the pre-enforcement review bar is constitutional both facially and as administered by EPA. Gen. Elec. Co. v. Jackson, 610 F.3d 110 (D.C. Cir. 2010). Courts evaluating CERCLA's liability scheme often rely on the Supreme Court's decision in *Elkhorn Mining Co. v. Usery*, 428 U.S. 1 (1976), in which the Court held that the black lung benefits provisions of the Coal Mine Health and Safety Act were constitutional even though they applied retroactive liability on mine owners. *See, e.g.*, Franklin County Convention Facilities Auth. v. Am. Premier Underwriters, Inc., 240 F.3d 534 (6th Cir. 2001) (citing *Elkhorn* to support its holding that retroactive application of CERCLA does not violate due process).

[26] *See, e.g.*, Land O'Lakes, Inc. v. United States, 2016 WL 552966, at *3 (W.D. Okla. Feb. 10, 2016) (Section 113(h) "bars subject matter jurisdiction over Plaintiff's claims [that it was not liable for cleanup costs] unless and until the EPA files a cost recovery claim under § 107 of CERCLA").

[27] Giovanni v. U.S. Dep't of Navy, 906 F.3d 94, 110 (3d Cir. 2018); Durfey v. E.I. DuPont de Nemours & Co., 59 F.3d 121, 126 (9th Cir. 1995). *But see* Hanford Downwinders Coalition, Inc. v. Dowdle, 71 F.3d 1469, 1484 (9th Cir. 1995); McClellan Ecological Seepage Situation v. Perry, 47 F.3d 325, 329 (9th Cir. 1995).

[28] 408 P.3d 515 (Mont. 2017). The Petition for Writ of Certiorari, filed April 27, 2018, provides a useful summary of the history of the case and pre-enforcement review bar caselaw, *available at* https://www.supremecourt.gov/search.aspx?filename=/docket/docketfiles/html/public/17-1498.html. On October 1, 2018, the U.S. Supreme Court invited the Solicitor General to file a brief expressing the views of the United States. 139 S. Ct. 305 (Oct. 1, 2018).

C. U.S. as Owner

For natural resource industries,[29] particularly in the American West, the answer to the question of the United States' liability at CERCLA sites on lands owned or administered by the United States government is particularly important.[30] Is legal title alone sufficient to establish current owner liability under CERCLA or is more in the way of "indicia of ownership" required? That question has now been answered definitively, in the Tenth Circuit at least, in *Chevron Mining, Inc. v. United States*,[31] where the court found the United States was an owner, and therefore a PRP, for the cleanup of the Questa Mine site in New Mexico. Molybdenum mining at the Questa Mine from 1919 to 2014 generated significant volumes of waste rock and tailings. Much of the mining occurred on Forest Service land. It was undisputed that the United States held legal title to relevant portions of the Questa Mine at the time of hazardous substance disposal.[32]

The *Chevron* court rejected the government's argument, based on the district court's decision in *United States v. Friedland*,[33] that CERCLA owner liability does not attach to the United States' "bare legal title." In *Friedland*, the court held that the United States, as "bare legal title holder to unpatented mining claims" on Forest Service land, did not qualify as a CERCLA "owner."[34] The *Friedland* court reasoned that the United States did not have sufficient "indicia of ownership" as compared to the operator of the Summitville Mine, to deem it an owner for purposes of CERCLA liability.[35] In rejecting *Friedland's* "indicia of ownership" test, the *Chevron* court held that the owner of any land contaminated with

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[29] CERCLA exempts "petroleum, including crude oil or any fraction thereof" and "natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel" from the definition of "hazardous substance." 42 U.S.C. 9601(14); however, "petroleum products mixed with hazardous substances not constituent elements of petroleum are hazardous substances. *Franklin County*, 240 F.3d at 541. Nonetheless, EPA has used CERCLA funding on at least one occasion to respond to water quality concerns in the Pavillion oil and gas field in Wyoming. *See* https://www.epa.gov/sites/production/files/documents/EPA_ReportOnPavillion_Dec-8-2011.pdf.

[30] *See* Jamie Futral et al., "Recent Developments in Environmental Law," 31 *Tul. Envtl. L.J.* 373, 380 (2018) ("If the United States senses it will be a PRP on public lands, the EPA could retreat from future NPL mine listings or abatement orders, relax its oversight over clean ups on public lands, or oversee more lax clean ups on public lands. The EPA does not normally retreat. However, in this current administration, which has focused on less government regulation, anything is possible.").

[31] 863 F.3d 1261 (10th Cir. 2017).

[32] *Id*. at 1275.

[33] 152 F. Supp. 2d 1234 (D. Colo. 2001).

[34] *Chevron*, 863 F.3d at 1275.

[35] *Id*. (quoting *Friedland*, 152 F. Supp. 2d at 1244); *see also* United States v. Newmont USA Ltd., 504 F. Supp. 2d 1050, 1070 (E.D. Wash. 2007) (in a case involving CERCLA liability for a uranium mine cleanup, the court found that it need not decide whether the U.S. would be subject to owner liability as the "bare legal title" holder of the Spokane Indian Reservation because the U.S. had sufficient "indicia of ownership" over the reservation property since it had general trust responsibilities and responsibilities under the Indian Mineral Leasing Act, which "imposes extensive responsibilities on the federal government when executing tribal mineral leasing on allotted, but non-patented land or on land owned by the tribe pursuant to treaty."); El Paso Natural Gas Co. v. United States, 2017 WL 3492993, at *2 (D. Ariz. Aug. 15, 2017) (holding that because the United States held legal title to uranium mines on the Navajo reservation, it was an owner for purposes of CERCLA liability; although the tribe retained a right of occupancy, referred to as "Indian title," this right "could be extinguished only by the [U.S.] and continued only at the pleasure of the [U.S.]).

hazardous substances "qualifies as an owner of a 'facility,' even if that person does not own any of the mining equipment or structures."[36] "[A]t a minimum, the term 'owner' covers fee title holders for purposes of CERCLA liability, irrespective of any additional indicia of ownership."[37] By contrast, the court found that the United States was not an arranger because it did not own or possess the hazardous substances at issue.[38]

D. Apportionment and Allocation

Parties under CERCLA can assert two types of claims to shift to other PRPs their appropriate or fair share of CERCLA joint and several liability. The first type of claim arises out of CERCLA § 107, and the courts' consistent interpretation that liability under CERCLA § 107 is joint and several, **unless** the environmental harm is theoretically capable of divisibility or apportionment and, if so, whether the defendants can prove as a matter of fact that there is a "reasonable basis" to apportion liability for the environmental harm among the parties to the case.[39] Successful apportionment efforts at CERCLA sites are few and far between, as the burden of proof remains high, even after the Supreme Court's decision in *Burlington Northern & Santa Fe Railway Co. v. United States* ("*BN*") suggested a potential easing of that burden.[40] Courts continue to describe this burden as

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[36] *Chevron*, 863 F.3d at 1277.

[37] *Id*.

[38] *Id*. at 1283–84. The United States has been found liable as an *arranger* at other CERCLA mine sites. In *Nu-West Mining, Inc. v. United States*, the U.S. District Court for the District of Idaho found the United States was an arranger where the U.S. had awarded leases on National Forest land for phosphate mining. Nu-West Mining, Inc. v. United States, 768 F. Supp. 2d 1082 (D. Idaho 2011). The United States required the lessees to obtain approval of its plans for mining, waste disposal, and reclamation, and conditioned approval of mine plans on lessees performing specific reclamation activities, including covering waste dumps with a layer of "middle waste shale" as a growth medium. The middle waste shale contained selenium, a hazardous substance. Nu-West, the current lessee, entered into an AOC with the United States to remediate the selenium contamination at the site, spent $10 million and sought to recoup these costs from the government, claiming the United States was an owner, operator, and arranger. *Id*. at 1086. The court found that the United States was an arranger because it had required the use of the middle waste shale to cover the waste dumps as a condition of mining approval, and thus had arranged for the disposal of selenium at the site. *Id*. at 1088. The court also imposed operator liability on the United States because it was "actively involved in the design and location of the waste dumps, and in ensuring that the waste dumps complied with the mining plans" and waste disposal guidelines. *Id*. at 1091. The United States admitted to being an owner for purposes of CERCLA liability. *Id*. at 1087. On the issue of the United States' liability as an *operator* for wartime activities, the court in *MRP Properties, LLC v. United States*, 308 F. Supp. 3d 916, 928 (E.D. Mich. 2018), recently held that a plaintiff must present substantial evidence that the United States had the requisite "indicia of control" of the contaminated facility, consistent with the Third Circuit's holding in *FMC Corp. v. U.S. Dep't of Commerce*, 29 F.3d 833, 843 (3d Cir. 1994).

[39] *See, e.g.*, Burlington N. & Santa Fe Ry. Co. v. United States, 556 U.S. 599 (2009) (adopting the common law approach from *Restatement (Second) of Torts* § 433A, to determine whether a harm is divisible).

[40] *Id*.; United States v. NCR Corp., 2017 WL 3668771, at *4 (E.D. Wis. 2017) ("Divisibility had taken on fresh significance as a defense following the Supreme Court's 2009 decision in *Burlington Northern* . . . ."); *see also* Ryan Brady, "CERCLA Apportionment Following Burlington Northern: How Joint and Several Liability Still Thrives—To the Surprise of Many," 4 *Wash. J. Envtl. L. & Pol'y* 141, 143 (2014) ("Courts applying Burlington Northern have maintained such high standards of evidence that no defendant has successfully demonstrated a reasonable basis. . . . Most commentators predicted at least a small increase in the likelihood of apportionment—a result unseen so far."); Jeffrey M. Gaba, "The Private Causes of Action Under CERCLA: Navigating the Intersection of Sections

"substantial" because the divisibility analysis is "intensely factual."[41] "When two or more causes produce a single, indivisible harm, 'courts have refused to make an arbitrary apportionment for its own sake, and each of the causes is charged with responsibility for the entire harm.'"[42]

The Ninth Circuit's recent decision in *Pakootas v. Teck Cominco Metals, Ltd.* is particularly instructive on liability apportionment under Section 107. The *Pakootas* litigation involves the Teck Cominco Metals, Ltd ("Teck") smelter in Trail, British Columbia, ten miles north of the British Columbia/Washington State border, and the alleged cross-jurisdictional, downstream impacts in Washington State from decades of smelting operations. The case has been to the Ninth Circuit four times, starting in 2006.[43] The most recent *Pakootas* decision rejects Teck's efforts to apportion or divide that liability.[44]

In evidence presented to the district court, Teck's divisibility expert had opined that Teck's slag did not travel far enough down river to reach the contaminated site, and that smelter slag, mine waste, and soil erosion from other locations and rivers that drained into the Columbia River were responsible for the contamination; accordingly, Teck should be apportioned a maximum 0.05% share of liability.[45] Consistent with the *BN* decision, the district court engaged in the two-part analysis set forth in the *Restatement (Second) of Torts* § 433A: (1) "the court considers whether the environmental harm is theoretically capable of apportionment," and (2) "if the harm is theoretically capable of apportionment, the fact-finder determines whether the record provides a 'reasonable basis' on which to apportion liability . . . ."[46]

In the first step of the divisibility analysis, a defendant must account for factors relating to the effect of the defendant's waste on the environment, including "when the pollution was discharged, . . . where the pollutants are found,

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107(a) and 113(f)," 5 *Mich. J. Envtl. & Admin. L.* 117, 127 (2015) ("Citing Restatement principles, courts, including the Supreme Court, have held that liability under section 107 is joint and several unless there is a discrete harm that provides a basis for allocating costs to parties. This possibility of division based on harm is more theoretical than real." (footnote omitted)).

[41] United States v. Alcan Aluminum Corp., 964 F.2d 252, 269 (3d Cir. 1992); PCS Nitrogen Inc. v. Ashley II of Charleston LLC, 714 F.3d 161, 182 (4th Cir. 2013) ("By its nature, apportionment necessarily requires a fact-intensive, site-specific analysis. . . . CERCLA's joint and several liability scheme may be 'terribly unfair in certain instances.'" (quoting *In re* Bell Petroleum Servs., Inc., 3 F.3d 889, 897 (5th Cir. 1993))).

[42] *Burlington Northern*, 556 U.S. at 614–15 (quoting *Restatement (Second) of Torts*, § 433A, cmt. i (1965)). *But see* Coeur d'Alene Tribe v. Asarco Inc., 280 F. Supp. 2d 1094, 1121 (D. Idaho 2003) (finding the defendants "presented concrete evidence to support divisibility" based on tailings production).

[43] Whether air quality impacts downwind of the smelter are actionable under CERCLA was decided in the negative in *Pakootas v. Teck Cominco Metals, Ltd.*, 830 F.3d 975 (9th Cir. 2016). However, the Ninth Circuit had previously held actionable under CERCLA the deposition of 8.7 million tons of slag and other process effluent on the riverbed and banks of the Columbia River in Washington. *See* Pakootas v. Teck Cominco Metals, Ltd., 452 F.3d 1066 (9th Cir. 2006); Pakootas v. Teck Cominco Metals, Ltd., 646 F.3d 1214 (9th Cir. 2011).

[44] Pakootas v. Teck Cominco Metals, Ltd., 905 F.3d 565 (9th Cir. 2018). The court also made findings that it had jurisdiction over Teck and that certain investigation costs and attorney fees were recoverable.

[45] *Id*. at 588.

[46] *Id*. at 588–89.

how the pollutants are presented in the environment, and what are the substances' chemical and physical properties."[47] These properties include "the relative toxicity, migratory potential, degree of migration, and synergistic capacities of the hazardous substances at the site."[48] There was evidence of the mixing of Teck's metals and wastes and other, unrelated hazardous substances. The court found that "the mixing of the wastes raises an issue as to the divisibility of the harm," and Teck chose not to address the "potential for synergistic harm from these pollution hotspots."[49] "[O]nce the State identified mixing of Teck's metals with non-metal pollutants, Teck was required to rebut the presumption that these pollution hotspots caused greater harm than the sum of the individual pollutants, each of which may be so widely dispersed as to be harmless on its own."[50] Because of these failures, the court held that Teck did not make a sufficient showing that liability was theoretically capable of apportionment.[51]

The court also found that Teck failed to present sufficient evidence that there was a "reasonable basis" for determining the contribution of each cause to a single harm. Teck presented no evidence showing a relationship between waste volume and the harm at the site and did not account for geography, including the flow of the Columbia River and metals loading from other sources.[52] Because Teck did not present evidence of how these and other factors affected the contamination of the site, "any apportionment would have been arbitrary."[53]

The several apportionment decisions in the Fox River CERCLA case are also instructive on the difficulties for the parties and the courts in trying to apportion CERCLA liability.[54] The case involved the cleanup of the Fox River in Wisconsin following years of discharging PCBs into the river by various paper mills.[55] The first round of decisions from the U.S. District Court for the Eastern District of Wisconsin and the U.S. Court of Appeals for the Seventh Circuit involved a preliminary injunction motion by the United States to enforce a unilateral order under CERCLA § 106. The issue relative to apportionment was whether NCR, a key PRP, was likely to succeed on the merits with its apportionment case. The Seventh Circuit, affirming the district court, ruled against NCR, finding that the amount of PCBs that each PRP discharged was not linearly correlated to the harm. Instead, NCR's contribution of PCBs to the harm alone was sufficient to trigger the need for cleanup. Therefore, the harm was not divisible.[56]

On a later remand on the same issue, the district court, after taking additional evidence, found that NCR had established that the harm to the Fox River was in

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[47] *Id*. at 591.

[48] *Id*.

[49] *Id*. at 592–93.

[50] *Id*. at 593.

[51] *Id*.

[52] *Id*. at 595.

[53] *Id*. at 596.

[54] *See* United States v. NCR Corp., 688 F.3d 833 (7th Cir. 2012); United States v. P.H. Glatfelter Co., 768 F.3d 662 (7th Cir. 2014); United States v. NCR Corp., 2015 WL 6142993, at *5 (E.D. Wis. Oct. 19, 2015), *reconsidering* 107 F. Supp. 3d 950 (E.D. Wis. 2015).

[55] *United States v. NCR Corp.*, 688 F.3d at 839.

[56] *Id*. at 840.

fact divisible. The court then reversed itself, ruling against NCR on a motion for reconsideration, after considering additional evidence, specifically finding that it was "largely a mystery" how NCR's expert arrived at NCR's contribution to the harm and otherwise rejecting NCR's approach to dividing the harm.[57]

The second method for allocating liability is "equitable allocation" in a CERCLA § 113 contribution action among the PRPs at a cleanup site. A PRP's burden of proof is much easier in this context, as the court is sitting in equity, and the district court "may allocate response costs among liable parties using such equitable factors as the court determines are appropriate."[58] However, these cases can nonetheless also be complicated and expensive to litigate, with the outcome subject ultimately and only to the equitable discretion of the court.[59] Parties often hire "allocation experts" who organize and present the pertinent evidence to the court and may also offer opinions as to what constitutes a fair allocation of liability, although the courts will often pick and choose from the experts' offerings,[60] as opposed to endorsing one expert's views over another.[61] Courts look to the well-known Gore Factors,[62] or the "Torres Factors," enumerated by Judge Torres in *United States v. Davis*.[63] However, the courts are not limited in the equitable factors they may consider in allocating costs, nor are they required to equally weigh all factors they apply; courts "may consider several factors, a few factors, or only one determining factor . . . ."[64] The lack of predictable guidance

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[57] *United States v. NCR Corp.*, 2015 WL 6142993, at *4.

[58] 42 U.S.C. § 9613(f)(1).

[59] *Id.*; *see also, e.g.*, ASARCO LLC v. Atlantic Richfield Co., 353 F. Supp. 3d 916 (D. Mont. 2018) (appeal pending); Browning-Ferris Industries of Ill., Inc. v. Ter Maat, 195 F.3d 953, 957 (7th Cir. 1999); United States v. Shell Oil Co., 294 F.3d 1045, 1060 (9th Cir. 2002) ("We reverse only for an abuse of the discretion to select factors, or for clear error in the allocation according to those factors.").

[60] United States v. Atlas Minerals & Chem., Inc., 1995 WL 510304 (E.D. Pa. Aug. 22, 1995).

[61] *But see ASARCO*, 353 F. Supp. 3d at 944 ("As between experts Hansen and Davis, the Court finds the opinions of expert Davis to be compelling and persuasive.").

[62] *See e.g.*, Lockheed Martin Corp. v. United States, 35 F. Supp. 3d 92, 123 (D.D.C. 2014), *aff'd*, 833 F.3d 225 (D.C. Cir. 2016).

[63] 31 F. Supp. 2d 45, 63 (D.R.I. 1998), *aff'd*, 261 F.3d 1 (1st Cir. 2001). Judge Torres adopted the following four "critical factors":

1. The extent to which cleanup costs are attributable to wastes for which a party is responsible.
2. The party's level of culpability.
3. The degree to which the party benefitted from disposal of the waste.
4. The party's ability to pay its share of the cost.

Id.; *see also* United States v. Consolidation Coal, 184 F. Supp. 2d 723, 747 (S.D. Ohio 2002), *vacated in part on other grounds*, 345 F.3d 409 (6th Cir. 2003) (applying the Torres factors to allocate 25% of the remediation costs to the owners and operators of a landfill facility and 60% to the generators and transporters of industrial waste).

[64] Envtl. Transp. Sys., Inc. v. ENSCO, Inc., 969 F.2d 503, 509 (7th Cir. 1992); Smith Land & Imp. Corp. v. Celotex Corp., 851 F.2d 86, 90 (3d Cir. 1988) (courts must resolve the allocation of response costs "on a case-by-case basis, taking into account relevant equitable considerations" (quoting H.R. Rep. No. 253(I) (1985), *reprinted in* 1986 U.S.C.C.A.N. 2835, 2861–62)); *Lockheed*, 35 F. Supp. 3d at 123. The court listed several factors that have been applied by courts, which include:

1. The "knowledge and/or acquiescence of the parties in the contaminating activities."
2. The value of the contamination-causing activities to furthering the government's national defense efforts.

and precedent on allocating the so-called "orphan share" of CERCLA liability (*i.e.*, the fair liability share of bankrupt, dissolved, and deceased parties) can be particularly unnerving in litigating these equitable claims.[65]

III. Mini-CERCLAs and Insurance Coverage

Certain states have their own CERCLA statutes. Montana is among the western states that do.[66] Colorado is among the states that do not.[67] The liability schemes and other considerations under these statutes can diverge from the federal statute. Washington's Model Toxics Control Act ("MTCA") allows the prevailing party in a private party contribution action to recover reasonable attorneys' fees and costs.[68] CERCLA does not.[69] In an analogue to the liability of federal agencies under CERCLA, the liability of state entities under these mini-CERCLA statutes also can be hotly contested.

For example, in *Pope Resources, LP v. Washington State Department of Natural Resources*, the Washington Supreme Court reversed the Court of Appeals, holding that the State of Washington Department of Natural Resources ("DNR") was not an owner or operator under MTCA of a sawmill and forest products manufacturing facility, located in part on state-owned tidelands, where the

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3. The existence of an indemnification agreement demonstrating "the parties'. . . intent to allocate liability among themselves."

4. "The financial benefit that a party may gain from remediation of a site."

5. The potential for windfall "double recoveries" by a plaintiff.

6. The potential that a plaintiff might "make a profit on the contamination" at the expense of another PRP.

7. CERCLA's intent that "responsible parties, *rather than taxpayers*, bear the costs" of cleanup.

Id. at 123–24 (emphasis in original) (internal citations omitted); *see also* Georgia-Pacific Consumer Prods. LP v. NCR Corp., 358 F. Supp. 3d 613, at 648 (W.D. Mich. 2018) (appeal pending) (accounting for all of the Gore and Torres factors to allocate cleanup costs 40% to the manufacturer of carbonless copy paper that created the PCBs that polluted the river, and 60% among three paper mills that contributed to the release of PCBs from the paper to the river).

[65] Monarch Greenback, LLC v. Twin Gold Corp., No. 98-0354, slip op. (D. Idaho Sept. 30, 2002) (in allocating the response costs among four PRPs, two of which were orphan shares, the court found that the orphan share was 50% of the costs, and found that the equitable allocation of the orphan share was an equal allocation between the two solvent PRPs).

[66] *See* Mont. Code Ann. § 75-10-701 *et seq*., Montana's Comprehensive Environmental Cleanup and Responsibility Act. Others are Washington, *see* Wash. Rev. Code § 70.105d.010 *et seq.*, Washington's Model Toxics Control Act; California, *see* Cal. Health & Safety Code § 25300 *et seq.*, Carpenter-Presley-Tanner Hazardous Substance Account Act; Oregon, *see* Or. Rev. Stat. §§ 465.200–.545 and 465.900; Arizona, *see* Ariz. Rev. Stat. § 49-281 *et seq.*, Water Quality Assurance Revolving Fund; Utah, *see* Utah Code § 19-6-301 *et seq*., Hazardous Substances Mitigation Act.

[67] The disposal of hazardous waste and regulation of hazardous waste disposal sites is governed by the Hazardous Waste Control Act, Colo. Rev. Stat. § 25-15-101 *et seq*.; *see also* Colo. Rev. Stat. § 25-8-601(2) (in Colorado, requiring the reporting of discharges to waters of the State in connection with "any operation or activity").

[68] Wash. Rev. Code § 70.105D.080; Louisiana-Pacific Corp. v. Asarco, Inc., 934 P.2d 685, 694 (Wash. 1997) (MTCA provides for the recovery of "reasonable attorneys' fees and expenses" as well as other "reasonably necessary expenses of litigation," i.e. costs, to the prevailing party in a private contribution action).

[69] Key Tronic Corp. v. United States, 511 U.S. 809, 817–19 (1994) (CERCLA § 107(a)(4) does not permit a "private party" to recover attorney's fees).

responsibility to manage these lands for the benefit of the public had been delegated to DNR.[70] The Supreme Court found that, in holding DNR liable under MTCA as an owner, the Court of Appeals had "interposed *ownership* attributes into the State's delegation of aquatic lands *management* to DNR."[71] While DNR leased the property to the sawmill facility, it was not an "owner" under MTCA.[72] The court further found that DNR was not an operator because DNR did not have the requisite control over the sawmill operations. It was undisputed that DNR did not control the daily operations, employees, or finances of the facility, and did not authorize or otherwise control the release of any hazardous substances at the facility.[73]

Insurance coverage law related to CERCLA cleanups also varies widely. Oregon has taken the extraordinary step of enacting a specific statutory scheme regulating that coverage.[74] Other states leave the CERCLA coverage questions to the courts.[75] There are a number of decisions discouraging coverage in states where one might expect more support for the so-called "restoration" or "cleanup economy."[76] The California Supreme Court, for example, has held that the meaning of "suit" under an insurance policy is limited to "a court proceeding

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[70] 418 P.3d 90, 95 (Wash. 2018), *reversing* Pope Res. LP v. Wash. State Dep't of Nat. Resources, 389 P.3d 699 (Wash. Ct. App. 2016); Wash. Rev. Code § 79.105.010.

[71] *Pope Res.*, 418 P.3d at 94.

[72] *Id*. at 97.

[73] *Id*. at 92, 99.

[74] Or. Rev. Stat. §§ 465.075–.480, Construction of insurance policies involving environmental claims. The legislature passed Senate Bill 297 in 2003, which amended sections 465.075 and 465.080 in 2003, and supplies rules of construction to the interpretation of any general liability policies involving environmental claims. It specifies that any action or agreement the Oregon Department of Environmental Quality or EPA where either directs, requests, or agrees that an insured take action with respect to contamination is a "suit" or "lawsuit" for purposes of insurance coverage, and that an insurer "has a duty to pay all sums arising out of a risk covered by the policy." *See* Or. Rev. Stat. § 465.080(2)(b), (3)(a). *See also* Anna M. Smith, "Environmental Cleanup and the Interpretation of Comprehensive General Liability Insurance Policies: A Lesson from the Oregon Legislature," 31 *J. Legis.* 217 (2004) (noting that SB 297 introduced an "all-sums" approach as part of a general state-wide "pro-policyholder" and "pro-environment stance"); Christopher R. Hermann et al., "The Unanswered Question of Environmental Insurance Allocation in Oregon Law," 39 *Willamette L. Rev*. 1131, 1133 (2003) (noting that "[i]n the wake of the Oregon Supreme Court's 1996 decision in St. Paul Fire & Marine Ins. Co. v. McCormick & Baxter Creosoting Co. and the Oregon Legislature' s enactment of the Oregon Environmental Cleanup Assistance Act [in 2003], CGL insurers gradually have changed course and have begun to pay for environmental pollution claims." (footnote omitted)).

[75] *See, e.g.*, Compass Ins. Co. v. City of Littleton, 984 P.2d 606, 622 (Colo. 1999) (finding an "EPA action under CERCLA is sufficiently coercive to constitute a 'suit' as that term is used in the insurance policies."); Gull Indus., Inc. v. State Farm Fire & Cas. Co., 326 P.3d 782, 784 (Wash. Ct. App. 2014) ("the duty to defend is triggered if a government agency communicates an explicit or implicit threat of immediate and severe consequences by reason of the contamination"); Land O' Lakes, Inc. v. Employers Mut. Liab. Ins. Co. of Wisconsin, 846 F. Supp. 2d 1007, 1022 n.16 (D. Minn. 2012), *aff'd sub nom.* Land O' Lakes, Inc. v. Employers Ins. Co. of Wausau, 728 F.3d 822 (8th Cir. 2013) (reviewing cases from numerous jurisdictions and noting that the "overwhelming majority of courts" have regularly rejected arguments by insurers that a PRP letter does not constitute a "suit" for insurance coverage purposes).

[76] *Compare* Sunburst School Dist. No. 2 v. Texaco, Inc., 165 P.3d 1079 (Mont. 2007) *and* Travelers Cas. & Sur. Co. v. Ribi Immunochem Research, Inc., 108 P.3d 469, 476 (Mont. 2005) (the word "sudden" in a pollution exclusion provision of an insurance policy must have a temporal aspect in its meaning to not be surplusage when used generally in conjunction with the word "accidental," and not merely a sense of something unexpected).

initiated by the filing of a complaint," and does not include a PRP letter or other pre-complaint environmental agency action.[77] The Eastern District of Washington also recently held that an insurer does not have a duty to defend after an insured agrees to perform cleanup work under an Agreed Order, because the costs of performing a remedial investigation/feasibility study ("RI/FS") are considered damages, rather than defense costs, and should be characterized as indemnity under the applicable insurance policies.[78]

IV. CERCLA Settlements

PRPs resolve their potential CERCLA liability at a site through one or more AOCs or Consent Decrees that, especially at mining sites, prescribe often extensive and expensive cleanup-related activities and payment obligations that can extend and endure over decades, and are subject to serious enforcement authorities and sanctions for non-performance. In certain circumstances, PRPs can also cash out their CERCLA liability pursuant to either an AOC or a Consent Decree.[79]

EPA has model AOCs and Consent Decrees, and associated guidance documents,[80] to cover most settlement scenarios, and is often loath to modify many sections of their models. Modifications to Consent Decree terms also require U.S. Department of Justice ("DOJ") concurrence.[81] While this rigidity is less than ideal, negotiating a consent agreement typically is preferable to being served with one of EPA's model unilateral administrative orders under CERCLA § 106, particularly given CERCLA's pre-enforcement review. It is in the context of these

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[77] Foster-Gardner, Inc. v. Nat'l Union Fire Ins. Co., 959 P.2d 265, 286 (Cal. 1998). *But see* United Nuclear Corp. v. Allstate Ins. Co., 285 P.3d 644, 656 (N.M. 2012) (holding that an accidental spill of radioactive liquid from a tailings pond of several uranium mines was "sudden" because it was "unexpected" and was thus not excluded by the pollution exclusion contained in the applicable insurance policies); Hecla Mining Co. v. New Hampshire Ins. Co., 811 P.2d 1083 (Colo. 1991) (finding pollution exclusion in insurance policies did not exclude coverage for damages from accidental discharge of pollutants from a mine tunnel because the discharge was "sudden and accidental," meaning unexpected and unintended).

[78] Travelers Indem. Co. v. City of Richland, No. 4:17-cv-05200, 2018 WL 4760526 (E.D. Wash. May 30, 2018).

[79] *See* Model Cashout Consent Decree for Ability to Pay Peripheral Parties, issued September 26, 2014, *available at* https://cfpub.epa.gov/compliance/models/view.cfm?model_ID=386; Model Cashout Consent Decree for Peripheral Party Settlements Not Based on Ability to Pay, *available at* https://cfpub.epa.gov/compliance/models/view.cfm?model_ID=542; Cashout Settlement Agreement for Ability to Pay Peripheral Parties, *available at* https://cfpub.epa.gov/compliance/models/view.cfm?model_ID=387; Cashout Settlement Agreement for Peripheral Party Settlements Not Based Upon Ability to Pay, *available at* https://cfpub.epa.gov/compliance/models/view.cfm?model_ID=536.

[80] *See, e.g.*, Guidance for Conducting Remedial Investigations and Feasibility Studies Under CERCLA, EPA 540/G-89-004 (Oct. 1988), *available at* https://www.epa.gov/superfund/superfund-remedial-investigationfeasibility-study-site-characterization; Rules of Thumb for Superfund Remedy Selection, EPA 540/R/97-013 (Aug. 1997), *available at* https://www.epa.gov/superfund/key-principles-superfund-remedy-selection; Ecological Risk Assessment Guidance for Superfund: Process for Designing and Conducting Ecological Risk Assessments, EPA 540-R-97-006 (June 1997), *available at* https://www.epa.gov/risk/ecological-risk-assessment-guidance-superfund-process-designing-and-conducting-ecological-risk; Risk Assessment Guidance for Superfund, *available at* https://www.epa.gov/risk/superfund-risk-assessment-human-health-topics.

[81] DOJ lawyers, rather than lawyers for EPA, typically litigate environmental enforcement actions.

unilateral orders that CERCLA's sting can be particularly painful.

EPA has the following models:

- RI/FS Administrative Settlement Agreement and Order on Consent;
- Cash-out Settlement Agreement for Peripheral Parties (including an ability-to-pay version);
- De Minimis Contributor Administrative Settlement Agreement and Order on Consent;
- De Minimis Landowner Administrative Settlement;
- Non-exempt De Micromis Party Administrative Settlement Agreement and Order on Consent; and
- Settlement Agreement for Recovery of Past Response Costs.

Each category of AOC has a Consent Decree analogue. In addition, there is the Model Consent Decree—the "RD/RA (Remedial Design/Remedial Action) Consent Decree" for final remedy implementation. In general, consent decrees are reserved for more complex and costly settlements, or where judicial approval and oversight is particularly important to the parties. Performance of a final remedy by a PRP at an NPL site typically would be addressed in a Consent Decree. EPA-required investigations and interim cleanup actions are often covered in AOCs.

From the PRP perspective, much of the model language in either the AOC or Consent Decree context seems one-sided, if not patently unfair. In negotiating these settlements, it is critical to focus on the language that is subject to modification and to otherwise ensure that the settlement clearly defines the parties' expectations and the PRP's obligations. This is often, to a significant degree, a "crystal ball" exercise, trying to accommodate the inevitable uncertainties associated with large-scale CERCLA site cleanups implemented over years or even decades. This approach—focusing on the topics and language where flexibility exists—is critical in work performance settlements to minimizing disputes under equally one-sided and largely non-negotiable model language relating to dispute resolution. In addition, this approach maximizes the likelihood the settling PRP(s), at the end of the day, get meaningful benefit from their hard-earned covenant not to sue, recognizing that the covenant language in the pertinent model is also largely non-negotiable.[82]

Notwithstanding all the challenges, it is possible to navigate and negotiate EPA's model agreements to innovative CERCLA outcomes. Examples include:

- *Coeur d'Alene Basin NPL Site, Idaho*[83]

  PRP with long and extensive mining history within the site resolved billions of dollars in cleanup and natural resource damages claims and 20 years of litigation in a cash-out consent decree with the United States, the State of

[82] *See*, *e.g.*, RD/RA Model Consent Decree, *available at* https://cfpub.epa.gov/compliance/models/view.cfm?model_ID=81; *compare* Model Cashout Consent Decree for Ability to Pay Peripheral Parties, *supra* note 79.

[83] Consent Decree, United States v. Hecla Limited, Nos. 96-0122, 91-0342, 94-0206, slip op. (D. Idaho June 13, 2011).

Idaho, and the Coeur d'Alene Tribe. Payments totaling over $300 million were paid out over three years. Because this was a cash-out settlement, there were no "new information/new conditions" reopeners.[84]

- *Rio Tinto Mine Site, Nevada*[85]

  Multiple PRPs negotiated a global final work performance settlement covering both final remedy implementation and natural resource damages. A potential NPL listing was deferred, under the so-called "Superfund Alternatives Approach,[86] to a state-led remedy, with limited EPA oversight. The Consent Decree allows for natural attenuation of metals post-remedy construction, and specifies milestones over time for water quality improvement, while allowing up to 20 years for compliance with surface water quality performance standards.

- *Mine Site, Nevada*[87]

  EPA executed a "deferral agreement" with the Nevada Division of Environmental Protection ("NDEP") under CERCLA § 105(h) to defer final listing at a proposed mine and mineral-processing NPL site. The deferral agreement assigns lead oversight authority to NDEP for remedy implementation at an "orphan-share" operable unit ("OU"); completion of a "CERCLA-equivalent" site-wide RI/FS; and selection and implementation of "CERCLA-protective" remedial actions for the remaining OUs. Deferral was conditioned on the remaining viable PRP (alleged to be responsible for other OUs at the site) entering an AOC with NDEP to complete the RI/FS and implement and partially fund the orphan OU remedy. NDEP will provide the balance of the orphan OU remedy funding.

These examples highlight that, notwithstanding the challenges working with the model settlement agreements present, there are ways to get to "yes," albeit particularly painful in the CERCLA context. Finding the hidden flexibility in, for example, the agreement's definitions, the "Parties Bound" section, the "Additional Work" language, and the attachments to the settlement document, are critical to moving these cases to settlement and keeping them out, or getting them out, of court.

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[84] *Id*.

[85] The Consent Decree is available at https://www.epa.gov/sites/production/files/2013-12/documents/riotinto-cd-2013.pdf; *see also* Adam S. Cohen, "The Rio Tinto Mine Site, Elko County, Nevada: A CERCLA Case Study," ABA Section of Environment, Energy, and Resources (2013), *available at* https://www.americanbar.org/content/dam/aba/events/environment_energy_resources/2013/10/21st_fall_conference/conference_materials/16-cohen_adam-paper.authcheckdam.pdf.

[86] *See* EPA Memorandum to Superfund National Policy Managers, "Revised Response Selection and Settlement Approach for Superfund Alternative Sites," OSWER 9208.0-18 (June 17, 2004).

[87] Administrative Settlement Agreement and Order on Consent, In the matter of Anaconda Copper Mine, *available at* https://semspub.epa.gov/work/09/100005264.pdf; EPA and Nevada Division of Environmental Protection National Priorities List Deferral Agreement, Anaconda Copper Mine Site, Lyon County, Nevada, *available at* https://semspub.epa.gov/work/09/100005205.pdf.

V. The Superfund Task Force and Other Reforms

Then EPA Administrator, Scott Pruitt, commissioned the Superfund Task Force on May 22, 2017.[88] The stated purpose of the Task Force is

> to provide recommendations on an expedited timeframe on how the agency can restructure the cleanup process, realign incentives of all involved parties to promote expeditious remediation, reduce the burden on cooperating parties, incentivize parties to remediate sites, encourage private investment in cleanups and sites and promote the revitalization of properties across the country.[89]

Pruitt ordered the Task Force to provide a set of recommendations on actions the EPA could take to:

- Streamline and improve the efficiency and efficacy of the Superfund program, with a focus on identifying best practices within regional Superfund programs, reducing the amount of time between identification of contamination at a site and determination that a site is ready for reuse, encouraging private investment at sites during and after cleanup, and realigning incentives of all involved parties to foster faster cleanups.
- The task force should propose recommendations to overhaul and streamline the process used to develop, issue or enter into prospective purchaser agreements, bona fide prospective purchaser status, comfort letters, ready-for-reuse determinations and other administrative tools under the agency's existing authorities used to incentivize private investment at sites.
- Streamline and improve the remedy development and selection process, particularly at sites with contaminated sediment, including to ensure that risk-management principles are considered in the selection of remedies at such sites. In addition, the task force should propose recommendations for promoting consistency in remedy selection and more effective utilization of the National Remedy Review Board and the Contaminated Sediments Technical Advisory Group in an efficient and expeditious manner.
- Utilize alternative and non-traditional approaches for financing site cleanups, as well as improvements to the management and use of Superfund special accounts.
- Reduce the administrative and overhead costs and burdens borne by parties remediating contaminated sites, including a reexamination of the level of agency oversight necessary.
- Improve the agency's interactions with key stakeholders under the Superfund program, particularly other federal agencies at federal

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[88] Memorandum from E. Scott Pruitt, "Prioritizing the Superfund Program" (May 22, 2017), *available at* https://www.epa.gov/sites/production/files/2017-05/documents/prioritizing_the_superfund_program_memo_5-22-2017.pdf.

[89] *Id*. at 2.

> facilities and federal potentially responsible parties, and expand the role that tribal, state and local governments, local and regional economic development zones and public-private partnerships play in the Superfund program. In addition, the task force should propose recommendations for better addressing the liability concerns of state, tribes and local governments.[90]

The Task Force released its first set of recommendations on July 25, 2017.[91] The report included 42 recommendations organized around five goals: (1) expediting cleanup and remediation; (2) reinvigorating responsible-party cleanup and reuse; (3) encouraging private investment; (4) promoting redevelopment and community revitalization; and (5) engaging partners and stakeholders.[92]

On July 23, 2018, the Task Force released its 2018 update on its recommendations.[93] The update was prepared to highlight "the numerous accomplishments achieved by the hard-working EPA staff who planned and implemented specific actions to expedite reduction of risks to human health and the environment and accelerate the reuse of properties affected by hazardous substance contamination."[94] One of those accomplishments was EPA's release of the Administrator's Emphasis List ("AEL") in December 2017, which included 21 NPL sites across the United States that EPA targeted for "immediate and intense attention."[95]

The following mine and mineral processing sites are included on the AEL:

- U.S. Smelter and Lead Refinery (aka USS Lead or East Chicago), East Chicago, Indiana
- Tar Creek, Ottawa County, Oklahoma
- Bonita Peak Mining District, San Juan County, Colorado
- Anaconda Co. Smelter, Anaconda, Montana
- Silver Bow Creek/Butte Area, Butte, Montana[96]

There have also been five full NPL site deletions and one partial deletion through July 1, 2018, and EPA is "on track" for ten more deletions in 2018.[97] To put these numbers in context, there currently are over 1,300 sites on the NPL. In addition, EPA has issued new guidance recommending the Regions consider using separate settlement tracks for remedial design and remedial action "to get work underway

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[90] *Id*.

[91] EPA Superfund Task Force Recommendations, *available at* https://www.epa.gov/sites/production/files/2017-07/documents/superfund_task_force_report.pdf (Task Force Recommendations).

[92] *Id*.

[93] EPA Superfund Task Force Recommendations: 2018 Update, *available at*: https://semspub.epa.gov/work/HQ/197209.pdf (2018 Update).

[94] *Id*. at 3.

[95] *Id.* at 8. The latest update of the AEL was published in July 2018. *Superfund Sites Targeted for Immediate, Intense Action*, *available at* https://www.epa.gov/superfund/superfund-sites-targeted-immediate-intense-action.

[96] "US EPA Superfund Task Force: Superfund Sites Targeted for Immediate, Intense Action - December 8, 2017," https://www.epa.gov/sites/production/files/2019-04/documents/ael_december_2017.pdf.

[97] 2018 Update, *supra* note 93, at 8.

quickly where negotiations for a single consent decree addressing both remedial design/remedial action are likely to be protracted."[98]

As part of the Superfund Task Force recommendations, EPA also has implemented several initiatives to better work with Bona Fide Prospective Purchasers ("BFPPs") and other third parties for cleanup and reuse of CERCLA sites. Certain of these initiatives are discussed below.

1. Updated Special Account Disbursement Guidance

On March 27, 2018, EPA issued Updated Special Account Disbursement Guidance to "provide guidance to regions on disbursing special account funds to [BFPPs] as an incentive to perform work as well as to potentially responsible parties as settlement incentives."[99] These sorts of "mixed funding" agreements have historically been disfavored by EPA, even though there is early EPA guidance supporting "mixed funding."[100]

2. Agreements with Third Parties to Support Cleanup and Reuse at Sites on the Superfund National Priorities List

The EPA and DOJ policy memorandum "Agreements with Third Parties to Support Cleanup and Reuse at Sites on the Superfund National Priorities List" was issued on April 17, 2018.[101] The memorandum encourages more frequent consideration of BFPP agreements and Prospective Purchaser Agreement ("PPAs"), when appropriate, to foster cleanup and reuse of NPL sites.[102] The memorandum notes that before the 2002 Brownfields Amendments added the BFPP defense to CERCLA,[103] EPA and DOJ used PPAs as a tool to address liability concerns of third parties who wanted to purchase and reuse contaminated properties.[104] Following the amendment, EPA issued guidance that the government would generally no longer be entering into PPAs except in limited circumstances.[105] The Task Force recommendations include the expansion of PPAs for BFPPs and prospective purchasers to specifically limit their liability.[106]

The obstacle in most BFPP agreements is that EPA has total discretion to decide what constitutes "reasonable steps" to qualify as a BFPP. If, for example, EPA deems perpetual water management and treatment as a reasonable

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[98] *Id*. at 9.

[99] *Id.*; *see also* EPA Memorandum, "Guidance on Disbursement of Funds from EPA Special Accounts to Entities Performing CERCLA Response Actions" (Mar. 27, 2018), *available at* https://semspub.epa.gov/work/HQ/100001089.pdf.

[100] EPA Memorandum, "Evaluating Mixed Funding Settlements Under CERCLA" (Oct. 20, 1987), *available at* https://www.epa.gov/sites/production/files/2013-10/documents/mixfnd-cercla-mem.pdf.

[101] *Available at* https://www.epa.gov/sites/production/files/2018-04/documents/sftf25-memo-ppa-bfpp-final-2018_2.pdf (Joint Agreements Memorandum).

[102] 2018 Update, *supra* note 93, at 9.

[103] 42 U.S.C. § 9607(r); 42 U.S.C. 9601(40) (defining the requirements to qualify as a BFPP).

[104] Joint Agreements Memorandum, *supra* note 101, at 1–2.

[105] *Id*. at 2 (citing EPA Memorandum, "Bona Fide Prospective Purchasers and the New Amendments to CERCLA" (May 31, 2002), *available at* https://www.epa.gov/sites/production/files/documents/bonf-pp-cercla-mem.pdf).

[106] Task Force Recommendations, *supra* note 91, at 15 (Recommendation No. 23).

prerequisite to BFPP status, very few volunteers are likely to sign up.[107] The Task Force recommendations also promote so-called "Comfort Letters" that as a practical matter often fall short of what prospective purchasers, and their lenders, require.

3. Redevelopment Focus List/Reuse Fact Sheets

In January 2018, EPA released the initial Redevelopment Focus List of 31 NPL Superfund sites with the greatest reuse potential.[108] EPA has since issued reuse fact sheets for all of these sites, plus an additional 32 sites.[109]

One of the sites on the reuse list is the Bunker Hill Mining & Metallurgical facility, which is part of the Coeur d'Alene Basin NPL Site. Bunker Hill Mining Corp. ("BHMC") is leasing the Bunker Hill Mine from the current owner, Placer Mining Corp. ("PMC"), and has an option to purchase the mine. The 2018 update to the Superfund Task Force recommendations touts the government's Consent Decree with BHMC as "present[ing] an opportunity for the potential reuse of a mine that has been shuttered and dormant for some time and offers … significant benefits to EPA's cleanup efforts at the Site."[110] Pursuant to the consent decree, BHMC will: (1) perform work required by two unilateral administrative orders EPA issued to the owner of the site, PMC, related to PMC's previous operations at the mine; (2) pay almost $1 million annually for water treatment costs incurred by EPA; and (3) pay up to $20 million on behalf of PMC for past costs incurred by EPA responding to releases of hazardous substances from the property.[111] According to EPA, the settlement agreement "and associated efforts at Bunker Hill employed a unique approach for addressing contamination from previous operations and waste generation from proposed operations at the Site."[112]

Certain of the other Task Force recommendations could be important at mine sites, including:

- Recommendation 3: Promote the Application of Adaptive Management at Complex Sites.
- Recommendation 5: Clarify Priorities for RI/FS Resources and Encourage Performing Interim/Early Actions During the RI/FS Process to Address Immediate Risks.

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[107] 2017 Consultant Communications with EPA on Brooklyn Mine, BPMD. EPA's efforts to develop a viable Good Samaritan policy for site cleanup for redevelopment activities have been similarly stymied by the requirement that an interested party cannot have a commercial interest in the project at issue. *See* EPA Memorandum, "Interim Guiding Principles for Good Samaritan Projects at Orphan Mine Sites and Transmittal of CERCLA Administrative Tools for Good Samaritans," at 3 (June 6, 2007), *available at* https://www.epa.gov/sites/production/files/2015-09/documents/cercla-goodsam-principles-mem-ed2015.pdf ("a Good Samaritan is an entity willing to perform cleanup work under CERCLA at an Orphan Mine Site even though it does not own the property, and does not intend to own it in the future.").

[108] 2018 Update, *supra* note 93, at 9.

[109] *Id.*

[110] *Id.* at 41.

[111] *Id.*

[112] *Id.*

- Recommendation 9: Utilize State-of-the-Art Technologies to Expedite Cleanup.
- Recommendation 11: Review All Third-Party Contracting Procedures, Large EPA-Approved Contractors, and Contracts to Determine Appropriate Use Parameters and Qualification Methods for EPA Contracts.
- Recommendation 13: Identify Opportunities to Utilize Various Federal and State Authorities to Conduct Response Actions That Are Consistent with CERCLA and the NCP.
- Recommendation 15: Speed Up Settlement Process Where There Are Federal PRPs at a Site.[113]

To the extent these recommendations and related policy changes reduce the technical costs associated with NCP compliance and the transaction costs associated with CERCLA settlements, these sorts of reforms are beneficial. Some of the favored reforms could have significant and potentially negative consequences depending on the setting. For example, the process of adaptive management provides a valuable feedback loop in ongoing planning at large complex sites. However, a PRP who agrees to implement an adaptive management ROD may have no certainty when they sign the Consent Decree as to the scope of the ultimate cleanup obligation or when its cleanup obligation is satisfied.

Similarly, EPA's new guidance document entitled "Bifurcating Remedial Design and Remedial Action to Accelerate Remedial Design Starts at PRP-Lead Superfund Sites"[114] is intended to expedite moving sites from further study to actual cleanup. However, because remedy design under the AOC is subject to EPA approval and enforcement, a PRP who enters into an AOC for remedy design to support a final remedy RD/RA Consent Decree potentially loses both significant control over the design process and significant leverage in then negotiating key work-related parameters in the RD/RA Consent Decree.

VI. EPA's Final Rule Governing CCR

EPA published its Final Rule governing the disposal of Coal Combustion Residuals ("CCR") produced by electric utilities and power plants under the solid waste provisions (i.e. Subtitle D) of RCRA on April 17, 2015.[115] CCR is the term for byproducts of coal combustion that occur at power plants, and includes "fly ash," "bottom ash," "boiler slag," and "flue gas desulfurization materials."[116] The Final Rule sets criteria intended to ensure that human health and the environment face "no reasonable probability" of harm from CCR spilling, leaking, or seeping

[113] Task Force Recommendations, *supra* note 91.

[114] *Available at* https://www.epa.gov/sites/production/files/2018-06/documents/bifurcate-rdra-cleanup-prp.pdf. This guidance recommends separate settlement and remedial action where negotiations of an RD/RA consent decree are likely to be protracted.

[115] *See* Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21,302 (Apr. 17, 2015).

[116] *See* Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128, 35,138 (proposed June 21, 2010).

from their storage units and harming humans and the environment.[117] Various provisions of the Final Rule were challenged under the Administrative Procedure Act and RCRA by environmental groups and by power companies and related trade associations.[118] The environmental groups claimed that EPA did not go far enough to protect the public and the environment because it allowed unlined impoundments for CCR disposal, as well as impoundments lined only with a layer of compacted soil, and because it exempted "legacy ponds"—inactive surface impoundments at shuttered power plants.[119] Among other challenges, the industry groups challenged whether EPA had provided adequate notice of certain restrictions in the Final Rule and the Rule's location restrictions and structural integrity criteria governing units in seismic impact zone.[120]

As to the claims raised by the environmental groups, the court held that "EPA acted arbitrarily and capriciously and contrary to RCRA in failing to require the closure of unlined surface impoundments, in classifying so-called 'clay-lined' impoundments as lined, and in exempting inactive surface impoundments at inactive power plants from regulation." The court therefore vacated and remanded the provisions of the Final Rule that permit unlined impoundments to continue receiving coal ash unless they leak, classified "clay-lined" impoundments as lined, and exempted from regulation inactive impoundments at inactive facilities.[121]

Regarding the industry petitioners' claims, the court held that:

> (i) the EPA has statutory authority to regulate inactive impoundments; (ii) the EPA provided sufficient notice of its intention to apply the aquifer location criteria to existing impoundments; (iii) the EPA did not arbitrarily issue location requirements based on seismic impact zones; and finally (iv) the EPA did not arbitrarily impose temporary closure procedures.[122]

The court also granted EPA's motion for voluntary remand and remanded to EPA the provisions in the Final Rule pertaining to (1) the definition of "Coal Residuals Piles"; (2) the 12,400-ton beneficial use threshold; and (3) the alternative groundwater protection standards.[123] The court denied EPA's motion to remand the provisions in the Final Rule pertaining to inactive surface impoundments and landfills at active power plants and inactive surface impoundments at inactive power plants.[124]

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[117] 80 Fed. Reg. at 21,338–39.

[118] Utility Solid Waste Activities Grp. v. EPA, 901 F.3d 414 (D.C. Cir. 2018).

[119] *Id*. at 425.

[120] *Id*.

[121] *Id*. at 449.

[122] *Id*. at 449–50.

[123] *Id*. at 449.

[124] *Id*. In addition, although EPA promulgated an amendment to the Final Rule during the pending litigation, the court declined to hold the petitions challenging the Final Rule in abeyance. *Id*. at 426 (citing 83 Fed. Reg. 36,435 (July 30, 2018)).

Oil and Gas Update: Legal Developments in 2018 Affecting the Oil and Gas Exploration and Production Industry

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The state reports presented below include key legal issues and developments in most of the more-active states in the areas of oil and gas exploration, development and production.

I. ALASKA

A. Legislative Developments

In June 2018, the Governor of Alaska signed into law HB 331, codified at Alaska Stat. §§ 37.18.010 et seq., which establishes the public Alaska Tax Credit Bond Corporation (ATCBC). The legislatively expressed purposes of the ATCBC are to, among other things, finance the purchase of over $800 Million in transferable tax credits for certain losses and expenditures and of alternative tax credits for oil and gas exploration, and pay claimed refunds for gas storage facility tax credit certificates, liquefied natural gas storage facility tax credits, and qualified in-state oil refinery infrastructure expenditures tax credits. The legislation allows the State of Alaska to issue nearly $1 Billion in bonds to pay off tax credits it owes to oil producers.

HB 331 has been challenged on constitutional grounds in the Superior Court for the State of Alaska.[2] The lawsuit alleges that such bond sales would cause the State of Alaska to legislatively incur debt above an amount permitted by the Alaska Constitution. First oral arguments were heard October 1, 2018.

B. Judicial Developments

In *State of Alaska, Dep't of Natural Res. v. Alaskan Crude Corp.*,[3] an oil and

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[2] Case No. 1JU-18-00699 Civil, available at https://records.courts.alaska.gov.

[3] Nos. S-16308/16417, slip op. (Alaska Aug. 31, 2018), https://public.courts.alaska.gov/web/appellate/opinions/sp-7283.pdf.

gas lessee conducted drilling activity on the last day of a lease term. The subject lease provided that such activity extended its term. Nevertheless, two days later, the State of Alaska, Department of Natural Resources (DNR), notified the lessee that the lease had expired. The lessee halted drilling activity and requested reconsideration and reinstatement. Several weeks later, the DNR granted reinstatement. However, the lessee insisted that the reinstatement terms added new and unacceptable conditions, and administratively appealed to the DNR. Six months later, the DNR terminated the lease, finding that the lessee failed to diligently pursue drilling after reinstatement.

The Superior Court for the State of Alaska reversed the DNR's termination and held that it materially breached the lease by reinstating it with new conditions. However, on appeal, the Alaska Supreme Court concluded that, although the DNR breached the lease, it cured the breach through reinstatement. The court also held that the DNR's later decision to terminate due to the lessee's failure to diligently pursue drilling activities following reinstatement was supported by substantial evidence. The Alaska Supreme Court reversed the superior court's reinstatement of the lease and affirmed the DNR's termination decision.

In the consolidated Alaska Supreme Court case *All American Oilfield, LLC v. Cook Inlet Energy, LLC*,[4] several questions were certified by the U.S. District Court for the District of Alaska and the U.S. Bankruptcy Court for the District of Alaska regarding Alaska's "dump lien" statute. Alaska Stat. § 34.35.140 creates a lien in favor of one who, at the instance of another in possession of an oil or gas well, performs such tasks as sinking, drilling, drifting, stopping, mucking, etc. in or about the well, or performs any other work necessary or convenient to the development, operation, or working of a well. The resulting lien encumbers the "dump or mass," or other minerals contained in or extracted from the well. Of crucial importance, these so-called dump liens are prior and preferred over a deed, mortgage or other claim, whether given before or after the work for which the lien is claimed is started.

In early 2018, the Alaska Supreme Court accepted the certified questions from the federal courts which ask, among other things: (1) whether a dump lien can apply to natural gas stored in its natural reservoir and, if so, whether a mineral "dump" was created when All American Oilfield, LLC drilled three natural gas wells at the request of Cook Inlet Energy, LLC (CIE); (2) whether a mineral "dump" was created each time CIE released gas from the natural reservoir in which the gas was formed, and then transported that gas via pipeline to a point of sale; and (3) whether a dump lien claimant must prove, in order to have a valid lien, that the gas produced was, in whole or in part, the product of the lien claimant's labor. At the time of this writing, oral argument was scheduled for March 20, 2019.

II. ARKANSAS

A. Judicial Developments

In Arkansas Oil & Gas Commission v. Hurd,[5] the Arkansas Supreme Court

[4] Nos. S-16974/S-17043 (consolidated) (Alaska filed Jan. 31, 2018 and Mar. 28, 2018), information available at http://www.appellate.courts.state.ak.us/frames1.asp?Bookmark=S16974 and http://www.appellate.courts.state.ak.us/frames1.asp?Bookmark=S17043.

[5] 564 S.W.3d 248 (Ark. 2018).

reversed a trial court's ruling holding that an appeal from an order of the Arkansas Oil and Gas Commission was barred by the doctrine of sovereign immunity. Article 5, Section 20 of Arkansas' Constitution provides: "The State of Arkansas shall never be made defendant in any of her courts." In Board of Trustees of University of Arkansas v. Andrews,[6] the court held that, contrary to some of its previous decisions, the Arkansas Legislature was powerless to waive that sovereign immunity by statute. A section of the Arkansas Administrative Procedure Act[7] provides a procedure for an appeal from an administrative agency in the form of an action in circuit court naming the agency as defendant. Relying upon *Andrews*, the trial court in *Hurd* ruled that provision of the Act unconstitutional as a legislative waiver of sovereign immunity. The trial court then proceeded to declare most of the remainder of the Administrative Procedure Act to also be unconstitutional because it allowed administrative orders from which, applying *Andrews*, there was no remedy through appeal. The Arkansas Supreme Court reversed, holding that *Andrews* only applied to actions where the state was the real party in interest. The state agency has no stake in the outcome of an appeal from its order, regardless of the literal reading of the constitutional provision. The state was not made a defendant in an appeal under the Administrative Procedure Act.

In *JS Interests, Inc. v. Hafner*,[8] a case discussed in the 2017 Year in Review report of this Committee, the U.S. District Court for the Eastern District of Arkansas had interpreted the parties' 1982 A.A.P.L. Form 610 Operating Agreement to require a unit's operator to pay overriding royalties to parties burdening a non-operating owner who was non-consent in the wells in question, ruling that such overriding royalty interests were not *subsequently created interests* because they were created by instruments recorded prior to the execution of the Operating Agreement. As part of a settlement of the case, the court vacated that ruling.[9]

In *Hicks v. Southwestern Energy Inc.*[10] the plaintiff's unleased mineral interest was subject to an Arkansas Oil and Gas Commission integration order binding him to a commission-approved form of oil and gas lease. That lease contains an "affiliate sale" provision requiring a lessee who sold to an affiliate[11] to pay proceeds royalty based upon a price no lower than that received from any other purchaser within the governmental township and range in which the lease is situated. Southwestern obtained the commission integration order and thus was the "lessee" under the integration lease. Southwestern paid royalties based upon the weighted average price of its sales (WASP) during the production month from all its Arkansas wells, which Hicks alleged was less than amount received by at least some other producers within the same township and range and thus violated the lease provision.

Hicks sought certification of a class of all unleased owners whose interests were integrated into Arkansas drilling units operated by Southwestern during the

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[6] 535 S.W.3d 616 (Ark. 2018).

[7] Ark. Code Ann. § 25-15-212.

[8] 2017 WL 5653873 (E.D. Ark. Feb. 10, 2017) and 2017 WL 3612857 (E.D. Ark. Aug. 22, 2017).

[9] 2017 WL 6459566 (E.D. Ark. Oct. 27, 2017).

[10] No. 4:16-cv-00226-KGB (E.D. Ark. dismissed Dec. 19, 2018).

[11] Defined by the "affiliate sales" clause as an entity having 10% common ownership.

relevant time period. The district court denied class certification, noting that the integration order to which the Hicks' interest was subject listed approximately 50 separate unleased mineral owners and purported to also bind any unknown spouse, heir, devisee, personal representative, successor or assigns thereof.[12] Moreover, during the relevant time period, Southwestern had obtained nearly 700 such integration orders in Arkansas, covering approximately 47 township and range combinations, each containing 36 separate drilling units. The court concluded that the identity of class members was not readily ascertainable. It also held the plaintiff's claims did not satisfy the typicality requirement of FRCP Rule 23(a) and that the proposed class failed to satisfy the requirements of FRCP rule 23(b)(3) since individual questions, rather than common questions predominated. Those individual questions went to both liability and damages, since both determinations would require ascertaining multiple third-party producers' prices, each month, in every township-range combination and comparing each "highest" price to Southwestern's WASP. Such an exercise, even if it were feasible, would likely produce different results for multiple different groups of class members.

In *Roberts v. Unimin Corp.*,[13] the Eighth Circuit affirmed a district court ruling granting summary judgment that upheld a mining lease which provided for a term of years and then so long thereafter as siliceous materials were shipped from the lessee's mill or at least as long as mining, mining operations, or transporting siliceous materials was taking place. The lessors advanced a number of theories why that language was either ambiguous or created a prohibited perpetuity. They contended that the lease became terminable at will at the end of its primary term, citing an Alabama decision which so held.[14] The district court held otherwise.[15] That ruling was later affirmed.

III. CALIFORNIA

A. Legislative Developments

Continuing its efforts to limit offshore oil and gas exploration and production, the California Legislature passed two bills, Assembly Bill No. 1775[16] and Senate Bill No. 834,[17] adding Section 6245 to the Public Resources Code to prohibit the State Lands Commission or a local trustee of granted public trust lands from entering into any new lease or other conveyance authorizing new construction of oil and gas related infrastructure upon tidelands and submerged lands within state waters associated with Outer Continental Shelf leases issued after January 1, 2018. The bills also imposed public notice, comment and process requirements should the commission or a local trustee consider a lease renewal, extension, amendment or modification to authorize the new construction of oil and gas related infrastructure associated with new federal leases.

The Legislature adopted Senate Bill No. 1147[18] requiring the State Oil and

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[12] 2018 WL 6252504 (E.D. Ark. Sept. 20, 2018).

[13] 883 F.3d 1015 (8th Cir. 2018).

[14] Linton Coal Co., Inc. v. S. Cent. Res., Inc., 590 So. 2d 911, 912 (Ala. 1991).

[15] Roberts v. Unimin Corp., 214 F. Supp. 3d 743 (E.D. Ark. 2016).

[16] Assembly Bill No. 1775, Stats. 2018, ch. 310.

[17] Senate Bill No. 834, Stats. 2018, ch. 309.

[18] Senate Bill No. 1147, Stats. 2018, ch. 607.

Gas Supervisor, before July 1, 2020, to evaluate and estimate the costs associated with the decommissioning of offshore oil and gas wells and, if necessary, to develop a schedule to increase the bond amounts or other financial surety provided by an operator of an offshore oil or gas well to ensure sufficient funds are available to the state to decommission the well if no other entity is responsible for those decommissioning costs. The bill also amended Section 6829 of the Public Resources Code to require that, as a condition for the approval of an assignment of an oil and gas lease from the State Lands Commission, the lease be modified to include additional provisions to secure the payment of the proper amount or value of production, drainage offset requirements, operational standards, and infrastructure bonding or other financial assurance requirements.

Senate Bill No. 1493[19] amended Section 3206 of the Public Resources Code to extend the annual deadline for operators to submit idle well fees from January 1 to May 1 of each year.

B. Judicial Developments

In Center For Biological Diversity v. Department of Conservation,[20] the court of appeal affirmed a trial court's denial of a petition for a writ of mandate by an environmental group to direct the Division of Oil, Gas, and Geothermal Resources (DOGGR) of the California the Department of Conservation to immediately order the shut-in of oil and gas wells which had been issued permits by DOGGR to inject fluids into nonexempt aquifers. DOGGR had discovered after issuing many permits that certain permitted wells may have been injecting into nonexempt aquifers. DOGGR and the U.S. Environmental Protection Agency (EPA) developed a corrective plan and DOGGR issued an emergency and permanent regulation[21] to address the problem over an approximately two-year period, which allowed some wells to remain in operation while the operator sought an aquifer exemption. The court rejected the petitioner's argument that DOGGR had a mandatory duty under the federal Safe Drinking Water Act (SDWA), EPA's regulations, and a memorandum of agreement between DOGGR and EPA, to immediately order the wells to stop injecting on the ground that, while the SDWA and EPA's regulations required DOGGR to protect nonexempt aquifers, they did not dictate a specific course of action to do so and DOGGR had discretion as to the manner in which it implemented the statutory mandate.

In *State of California v. BLM*,[22] the court issued a preliminary injunction restraining the Bureau of Land Management (BLM) from implementing its December 8, 2017, rule (the "Suspension Rule")[23] which would have suspended and delayed the requirements of the BLM's November 2016 "Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule."[24] The court found that the Suspension Rule was not grounded in a reasoned analysis by BLM, and irreparable harm in the form of waste of publicly-owned natural gas, increased

[19] Senate Bill No. 1493, Stats. 2018, ch. 742.

[20] 236 Cal. Rptr. 3d 729 (Ct. App. 2018) (review denied Oct. 24, 2018).

[21] Cal. Code Regs. tit. 14, §§ 1760.1, 1779.1.

[22] 286 F. Supp. 3d 1054 (N.D. Cal. 2018).

[23] 82 Fed. Reg. 58,050, 58,051 (Dec. 8, 2017).

[24] 81 Fed. Reg. 83,008 (Nov. 18, 2016).

air pollution, exacerbated climate harms, and other environmental injury would likely occur in the absence of an injunction.

C. Administrative Developments

DOGGR is the California agency responsible for regulating underground gas storage projects. As previously reported, the California Legislature responded to the October 23, 2015 natural gas leak at the Aliso Canyon Natural Gas Storage Facility in Los Angeles County through Senate Bill 887[25] enacted in 2016 new requirements for underground gas storage facilities. As part of its regulatory response to this legislative mandate, DOGGR adopted new regulations, effective on October 1, 2018,[26] which include new requirements for well construction, risk management plans, testing and monitoring requirements for gas storage wells and underground gas storage facilities.

California's Public Resources Code requires DOGGR to prescribe minimum facility maintenance standards for oil and gas production facilities, including pipelines that are not under the jurisdiction of the State Fire Marshal. Larger gas pipelines in non-urban areas had not been previously covered by DOGGR's testing and inspection regulations. As required by the 2015 California Assembly Bill No. 1420,[27] DOGGR adopted new regulations, effective on October 1, 2018, imposing testing and inspection requirements for active gas gathering lines in environmentally sensitive areas and urban pipelines, regardless of diameter.[28]

In July 2018, DOGGR established an Office of Enforcement as a dedicated statewide enforcement unit comprised of engineering, geologists and legal staff to identify and investigate violations and track compliance.[29]

The Office of Spill Prevention and Response (OSPR) of the California Department of Fish and Wildlife re-adopted emergency regulations on July 30, 2018 regarding oil spill contingency plans for inland facilities that could impact inland waters,[30] financial responsibility requirements[31] and modifications to requirements for the oil spill response drills and exercises of inland facilities.[32] The emergency regulations will be valid for 12 months while OSPR proceeds through the rulemaking process for final regulations.

IV. COLORADO

A. Legislative Developments

The Colorado legislature enacted Senate Bill 18-230 modifying Colorado's forced pooling statute.[33] The bill clarifies that, commencing July 1, 2018, an order

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[25] S.B. 887, Stats. 2016, ch. 673, 2015-2016 Reg. Sess. (Cal. 2016).

[26] Adding a new article 4 to Title 14, division 2, chapter 4, subchapter 1 of the California Code of Regulations, entitled "Requirements for Underground Gas Storage Projects."

[27] A.B. 1420, 2015-2016 Reg. Sess. (Cal. 2015), adding Cal. Health & Safety Code § 101042, and Cal. Pub. Res. Code §§ 3270.5 and 3270.6.

[28] Cal. Code Regs. tit. 14, §§ 1760, 1774, 1774.1, 1774.2.

[29] See July 16, 2018, DOGGR press release at https://www.conservation.ca.gov/index/Documents/news/2018-07%20new%20DOGGR%20enforcement%20unit%20%20announced.pdf.

[30] Cal. Code Regs. tit. 14, §§ 817.04 et seq.

[31] *Id.* §§ 791 et seq.

[32] *Id.* § 802.

[33] Senate Bill 18-230 (approved June 1, 2018), modifying Colo. Rev. Stat. § 34-60-116.

entered by the Colorado Oil and Gas Conservation Commission (COGCC) to pool oil and gas resources within a drilling unit may authorize more than one well.[34] The order must specify that a nonconsenting owner is immune from liability for costs arising from spills, releases, damage, or injury resulting from oil and gas operations on the drilling unit.[35] In the provision relating to reimbursement of consenting owners who pay for the nonconsenting owner's proportionate share of costs and risks out of the nonconsenting owner's share of production, the exclusion with respect to the owner's royalty and other non-cost-bearing interests now is limited "if and to the extent that the royalty is consistent with the lease terms prevailing in the area and is not designed to avoid the recovery of costs provided for" in the statute.[36] The provision prohibiting entry of a pooling order until the mineral rights owners have been given a reasonable offer to lease their rights was modified to specify that the offer must be given at least 60 days before the hearing on the order and must include a copy of or link to a brochure supplied by COGCC that describes the pooling procedures and the mineral owner's options.[37]

While numerous bills were proposed in the 2018 legislative session that either would have restricted or eased restrictions on oil and gas operations, none of them passed. Thereafter, Proposition 112 was included on the Colorado ballot as a citizen initiated statutory amendment to mandate that any new oil and gas development in Colorado be located at least 2,500 feet from any structure intended for human occupancy and other areas designated as vulnerable (including drinking water sources, canals, reservoirs, lakes, rivers and streams and other areas designated by state or local government). Proposition 112 was defeated in the November 6, 2018, election.

B. Judicial Developments

In *Maralex Resources, Inc. v. COGCC*,[38] the Colorado Court of Appeals upheld the trial court's order affirming an order finding violation issued by the COGCC. Maralex (the operator) and the O'Hares (surface owners) contended that Rule 204, which permits authorized COGCC staff "the right at all reasonable times to go upon and inspect any oil or gas properties,"[39] violates the United States and Colorado Constitutions. The appellate court upheld the district court's ruling that Rule 204 is constitutional because it permits searches falling within the *Colonnade-Biswell* administrative search exception to the warrant requirement.[40] Under this exception "a warrantless inspection made pursuant to a regulatory scheme of a closely regulated industry is reasonable if three requirements are met."[41] First, the regulatory scheme "must be informed by a substantial

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[34] Colo. Rev. Stat. § 34-60-116(3), as modified by S.B. 18-230.

[35] *Id.* § 34-60-116(7)(a)(III) (added by S.B. 18-230).

[36] *Id.* § 34-60-116(7)(a)(I), as modified by S.B. 18-230.

[37] *Id.* § 34-60-116(7)(d)(I), as modified by S.B. 18-230.

[38] 2018 COA 40, 428 P.3d 657, *cert. denied*, No. 18SC315, 2018 WL 5053134 (Colo. Oct. 15, 2018).

[39] COGCC Rule 204.

[40] The exception was developed in *Colonnade Catering Corp. v. United States*, 397 U.S. 72 (1970), and *United States v. Biswell*, 406 U.S. 311 (1972).

[41] *Maralex*, 428 P.3d at 662 (quoting Eddie's Leaf Spring Shop & Towing LLC v. Colo. Pub. Utils. Comm'n, 218 P.3d 326, 332 (Colo. 2009)).

government interest."[42] Second, warrantless searches must be necessary to further that government interest.[43] Third, the regulatory scheme must "provide a 'constitutionally adequate substitute' for a warrant in terms of certainty and regularity of the program's application."[44] Citing the authority granted COGCC to regulate oil and gas facilities by the Oil and Gas Conservation Act,[45] the court first found that the oil and gas industry is closely regulated.[46] The court then found that the three additional criteria necessary to make warrantless inspections were satisfied. In particular, it concluded that the state has a substantial interest in regulating oil and gas operations,[47] that warrantless searches are necessary to further the state's substantial interest in the safe and efficient operation of oil and gas facilities,[48] and that the occurrence of warrantless COGCC inspections was not "so random, infrequent or unpredictable that the owner, for all practical purposes, has no real expectation that his property will from time to time be inspected by government officials."[49] The court reached the same conclusion under the Colorado Constitution with little discussion.[50]

Spring Creek Exploration & Production Co. v. Hess Bakken Investment, II, LLC[51] involved, among other things, interpretation of an area of mutual interest (AMI) agreement containing a Colorado choice of law provision that covered oil and gas property in North Dakota known as the Tomahawk Prospect. Due to issues that arose out of a prior agreement that Hess had with Statoil Oil & Gas, LP, Hess assigned to Statoil most of the leases in the Tomahawk Prospect that it had acquired from Spring Creek and Gold Coast Energy, LLC, and Hess did not acquire any additional new leases within the Tomahawk Prospect during the remainder of the three-year term of its AMI with Spring Creek and Gold Coast. Spring Creek and Gold Coast sued Hess, claiming that the failure to acquire any new leases was a breach of contract and breach of the implied covenant of good faith and fair dealing. The Tenth Circuit upheld the district court's dismissal of both of those claims as a matter of law. The AMI agreement contained fairly standard language specifying Hess's obligations to the other parties "[i]f, during the term of the AMI, [Hess] should acquire any oil and gas lease, leasehold interest or mineral interest."[52] The Tenth Circuit agreed with the trial court that the language of the AMI agreement was not ambiguous and plainly did not *require* Hess to acquire new leases.[53] It rejected plaintiffs' arguments that a recital and a broker provision in the AMI agreement resulted in ambiguity as to whether Hess was required to acquire new leases.[54] The court also concluded that the plaintiffs

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[42] *Id.*

[43] *Id.*

[44] *Id.*

[45] Colo. Rev. Stat. §§ 34-60-101 to -130.

[46] 428 P.2d at 663–64.

[47] *Id.* at 664.

[48] *Id.*

[49] *Id.* (quoting Donovan v. Dewey, 452 U.S., 594, 599 (1981)).

[50] *Id.* at 665.

[51] 887 F.3d 1003 (10th Cir. 2018).

[52] *Id.* at 1010.

[53] *Id.* at 1018.

[54] *Id.* at 1018–19.

were not deprived of the benefit of their bargain under this interpretation of the AMI agreement.[55] Finally, the court concluded that since the AMI contract did not contain any requirement that Hess obtain new leases, Hess did not breach the implied covenant of good faith and fair dealing under Colorado law when it stopped trying to acquire new leases.[56]

Two cases involved suits by environmental groups under the Administrative Procedure Act (APA) challenging BLM decisions relating to exploration and development of federal oil and gas. One case related to the first stage of BLM decision making—development of a resource management plan (RMP). In *Wilderness Workshop v. BLM*,[57] the federal district court agreed with plaintiffs that the BLM failed to adequately consider greenhouse gas impacts from oil and gas consumption in its new RMP for the Colorado River Field Office (which administers more than 700,000 acres of federal minerals in western Colorado). In particular, BLM violated the National Environmental Policy Act (NEPA) "by not taking a hard look at the indirect effects resulting from the combustion of oil and gas in the planning area under the RMP."[58] Further, BLM "failed to consider reasonable alternatives to oil and gas leasing and development" when it did not closely study an alternative that closes to leasing lands with low and medium potential for oil and gas development.[59]

The other case related to BLM's analysis prior to leasing—the second step in BLM decision-making. In *Wildearth Guardians v. BLM*,[60] the federal district court concluded that the plaintiff had not met its burden of proving that BLM had acted arbitrarily or capriciously in concluding that it had no duty to perform a National Ambient Air Quality Standards (NAAQS) "conformity" analysis under the Clean Air Act prior to its oil and gas lease auctions of tracts in eastern Colorado (much of which is in nonattainment status for ozone) in May and November of 2015. Relying on EPA's General Conformity Rule,[61] BLM had concluded that it had no duty to forecast whether the lease sale would prolong the ozone problems in the nonattainment area because it was not reasonably foreseeable that either sale would indirectly lead to 100 tpy in emissions of an ozone precursor.[62] However, the court signaled that it likely would have decided in favor of the plaintiffs had they framed their argument relating to reasonable foreseeability in terms of the small number of wells operating in a single year that it would take to exceed that limit.[63]

Finally, 2018 presented an oil and gas tax case. In *Bill Barrett Corp. v. Lembke*,[64] the Colorado Court of Appeals upheld the taxation of oil and gas produced by the lessees of severed mineral owners by a special district established

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[55] *Id*. at 1019.

[56] *Id.* at 1019–20.

[57] 342 F. Supp. 3d 1145 (D. Colo. 2018).

[58] *Id.* at 1156.

[59] *Id.* at 1167.

[60] 322 F. Supp. 3d 1134, 1148 (D. Colo. 2018).

[61] 40 C.F.R. §§ 51.851, 93.150–.165.

[62] 322 F. Supp. 3d at 1141.

[63] *Id.* at 1143.

[64] 2018 COA 134, 2018 WL 4225030 (Colo. Ct. App. Sept. 6, 2018) (unpublished) (reh'g denied Oct. 4, 2018).

to develop water infrastructure. Neither the severed mineral owners nor the lessees had consented to inclusion of the property in the special district. The court concluded that the owner of the severed mineral estate is a "fee owner"[65] under Colorado's Special District Act,[66] but the severed mineral interest is not "real property capable of being served with facilities of the special district" under that statute.[67] Thus, the land could be included in the special district without consent of owners of the severed mineral estate. Also, while the court agreed that interests in oil and gas leases are characterized as interests in real property, it declined to treat lessees as "fee owners" under the statute.[68]

C. *Administrative Developments*

COGCC completed the rulemaking begun in 2017 to strengthen its flowline regulations and modify its related safety rules, effective May 1, 2018. COGCC's rules were modified to add registration requirements for off-location flowlines (i.e. those that transport fluids between different locations), including geophysical data necessary for identifying the specific location of new off-location flowlines[69] (and similar data for pre-existing off-location flowlines if the operator has it).[70] COGCC regulations now require that operators record new instruments that grant rights of access or easements for off-location flowlines, or a memorandum or notice of it, in the county records.[71] Registration requirements were added for installed domestic taps[72] and crude oil transfer lines and produced water transfer systems.[73] COGCC adopted new requirements relating to design, installation, repair and maintenance of flowlines and crude oil transfer systems, including industry standards that operators must follow when designing and installing their pipelines and repairing or replacing existing pipelines or segments of such pipelines.[74] Operators are required to become Tier One members of the Utility Notification Center of Colorado (UNCC), Colorado's "one-call" program that property owners rely on when preparing to dig, and to supply digital information about an operator's belowground operations to UNCC.[75] COGCC increased testing requirements for all flowlines and crude oil transfer lines,[76] and revised the abandonment provisions for flowlines and crude oil transfer lines.[77]

V. KANSAS

A. *Legislative Developments*

Kansas amended the Gas Safety and Reliability Policy Act, codified at Kan.

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[65] *Id.* at *7.

[66] Colo. Rev. Stat. §§ 32-1-101 et seq.

[67] 2018 WL 4225030, at *10.

[68] *Id.* at *8.

[69] *See* COGCC Rule 1101.a(2)A.

[70] *See* COGCC Rule 1101.a(2)B.

[71] *See* COGCC Rule 1101.a(4).

[72] *See* COGCC Rule 1101.b.

[73] *See* COGCC Rule 1101.c.

[74] *See* COGCC Rule 1102.

[75] *See* COGCC Rule 1102.n.

[76] *See* COGCC Rules 1103 and 1104.

[77] *See* COGCC Rule 1105.

Stat. Ann. §§ 66-2201 to -2204, which allows natural gas pipeline utilities, with authorization from the Kansas Corporation Commission, to recover certain legally required infrastructure replacement costs through a Gas System Reliability Surcharge (GSRS). The amendment broadens the law to allow utilities to petition the Commission for a GSRS to recover capital investments for facility upgrades and cyber security systems. It also raises existing caps on GSRS-generated revenues and the maximum monthly GSRS charges to residential customers. The amendment is effective January 1, 2019.

B. Judicial Developments

2018's most significant judicial development is the Kansas Supreme Court's holding in LCL, LLC v. Falen[78] that negligence and breach of fiduciary duty claims against a title company for failing to except mineral interests in drafting a deed are subject to the statute of limitation's discovery rule. In 2008 the parties hired Rice County Abstract as closing agent and to prepare the deed in the purchase and sale of real property. Rice County Abstract failed to except the minerals from the deed in compliance with the parties' contract and the deed was recorded at closing. Despite the error the sellers continued to receive royalties as though they had retained the minerals. In 2014 Rice County Abstract again acted as closing agent and prepared the deed for a sale of the same property and again failed to except the minerals from the deed. The new purchaser then asserted ownership of the minerals and royalty and sued to quiet title. The original seller answered the quiet title suit and asserted third-party claims for negligence and breach of fiduciary duty against Rice County Abstract for its poor draftsmanship. The trial court ruled in favor of Rice County Abstract on its statute of limitations defense, but the court of appeals reversed finding that the claims did not accrue until the original sellers first suffered substantial injury in 2014 when they stopped receiving royalties. The Kansas Supreme Court affirmed the court of appeals but rejected its analysis. The court reasoned instead that the cloud on sellers' title to the minerals created by the erroneous 2008 deed was *substantial injury* but that under the discovery rule the claim did not accrue until the sellers could *reasonably ascertain* the fact of the injury. The court found further that the deed's recording did not make the injury reasonably ascertainable as a matter of law and remanded the case for factfinding on whether the sellers should have ascertained the injury in 2008 when signing the deed.

The Kansas Court of Appeals issued an unpublished but significant opinion in Adamson v. Drill Baby Drill, LLC[79] addressing the burden of proof in actions brought to cancel an oil and gas lease for lack of production in paying quantities during its secondary term. The plaintiffs, owners of the surface of property covered by defendant's oil and gas leases, sued to terminate the leases for failure to produce oil in paying quantities. To establish nonproduction the plaintiffs relied exclusively on publicly available production records maintained on the internet by the Kansas Geological Survey (KGS). The trial court granted defendant summary judgment and plaintiffs appealed arguing the lessee defendant should bear the initial burden of proving the existence of production to sustain the lease and the burden was not on the plaintiff to show the absence of adequate production. The

[78] 422 P.3d 1166 (Kan. 2018).

[79] 409 P.3d 874 (table) (Kan. Ct. App. Jan. 26, 2018) (unpublished) (petition for review denied).

court of appeals affirmed summary judgment holding that the initial burden in an action to terminate an oil and gas lease for failure to produce in paying quantities is on the plaintiff to show by competent evidence a lack of production, and, if satisfied, the burden shifts to the defendant to prove the lease did not terminate. The court further held that the online records of the KGS were insufficient evidence to satisfy the plaintiffs' burden in this case. The plaintiffs asserted the KGS records showed no production from the inception of the leases in 1918 through 1953 and showed insufficient production from 1953 through 1984. The court found the evidence lacking because the KGS does not maintain records before 1953 and does not certify the accuracy of records maintained before 1987 as lease operators were not at that time obligated to report production.

In another unpublished decision, Batman v. Deutsch,[80] the court of appeals addressed a ubiquitous but not often litigated provision of oil and gas leases—the change in ownership clause, which requires the lessor to notify the lessee of any change in mineral or royalty ownership in the leasehold premises as a condition to the lessee's liability for directing lease payments to the transferee. Deutsch purchased and operated an oil and gas lease on minerals owned in severalty by the Batmans and two companies, Robro and Bitter End. Robro and Bitter End owned the minerals underlying the ten-acre tract surrounding the only existing well and therefore received all royalties payable on production from the well. Deutsch drilled a new well on a portion of the premises in which the Batmans owned the minerals but directed the first purchaser to pay all resulting royalties to Robro and Bitter End. Defending a subsequent suit for breach of contract by the Batmans, Deutsch argued the Batmans failed to comply with the lease's change in ownership provision. The trial court rejected Deutsch's defense finding that only the payor of the royalties—here, the first purchaser instead of Deutsch—is entitled to invoke the clause. The court of appeals affirmed but reasoned instead that the clause did not apply because the Batmans owned their interest in the minerals when Deutsch acquired the lease. In other words, a lessee cannot invoke the change of ownership provision when the ownership at issue was already in place when the lessee acquired its rights under the lease.

C. Administrative Developments

The Conservation Division of the Kansas Corporation Commission is primarily responsible for regulating the state's oil and gas industry and is funded in large part through an assessment on each barrel of crude oil and thousand cubic feet (Mcf) of natural gas sold in the state. In 2018 the Commission increased the crude oil and natural gas assessments promulgated in regulations Kan. Admin. Regs. §§ 82-3-206 and -307, respectively. The changes increased the monthly assessment on each barrel of crude oil marketed or used in the state to 144.00 mills, and on each Mcf of gas sold or marketed in the state to 20.50 mills. Under the regulations the first purchaser of production is responsible for deducting the amount of the assessment from production proceeds and remitting it to the Conservation Division.

[80] 423 P.3d 1062 (table) (Kan. Ct. App. Aug. 24, 2018) (unpublished).

VI. LOUISIANA

A. *Legislative Developments*

As a result of cases like *J&L Family, L.L.C. v. BHP Billiton Petroleum Properties (N.A.), L.P.*,[81] the legislature has proposed an edit to La. R.S. 31:212.21 in manner that would embrace the finding in *Adams v. Chesapeake Operating Co.*[82] Louisiana House Bill No. 444 of the 2018 Regular Session proposes an addition of the following language to La. R.S. § 31:212.21: "A mineral production payment is an obligation owed to the purchaser to make a payment from the proceeds of production and does not mean, include, or encompass the payments owed on production to an unleased mineral owner." The proposal was under consideration at the time of the submission of this paper.

B. *Judicial Developments*

For the past 15 years, environmental legacy litigation has been one of the most active areas of oil and gas law in Louisiana. While legacy suits are primarily aimed at addressing environmental damage to property, many of the threshold issues involve significant intricacies of oil and gas law. This year was no different. Three significant oil and gas decisions were handed down in the context of legacy suits. Each will be addressed in turn.

In *Global Marketing Solutions, LLC v. Blue Mill Farms, Inc.*,[83] the First Circuit Court of Appeal considered whether a landowner was legally entitled to seek injunctive relief in the place of the Commissioner of Conservation who was notified of alleged regulatory violations. This issue arose as a result of the landowner's pivot to salvage some claim against the oil company defendants in light of the dismissal of their tort and contract claims under the subsequent purchaser doctrine, as upheld previously by the Louisiana Supreme Court in *Global Marketing Solutions, LLC v. Blue Mill Farms, Inc.*[84] Prior to amending their petition to add claims for injunctive relief under La. R.S. 30:14 and 30:16, plaintiff sent two letters to the Commissioner of Conservation complaining about alleged regulatory violations which contaminated the property. Plaintiff requested that the Commissioner file suit or else plaintiff would do so under La. R.S. § 30:16. In response to plaintiff's letters, the Commissioner issued a compliance order seeking a work plan for assessing the soil and groundwater conditions at the site. When plaintiff amended its petition, it claimed the Commissioner failed to act, thus affording plaintiff the right to seek relief through a citizen suit under La. R.S. 30:14 and 30:16. The appellate court reversed the trial court's decision and held that the statutory requirements were fulfilled to allow plaintiff to assert a cause of action. One judge dissented because he interpreted the complaint as a whole to be alleging wholly past violations rather than present or ongoing violations. A concurring judge indicated other procedural actions may be available to address the potential inconsistency of whether La. R.S. §§ 30:14 and 30:16 are intended to apply to past or present violations. The case was remanded for further proceedings.

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[81] 293 F. Supp. 3d 615 (W.D. La. 2018).

[82] 561 F. App'x 322 (5th Cir. 2014).

[83] 2018 WL 5816971 (La. App. 1 Cir. 11/6/18).

[84] 153 So. 3d 1209 (La. App. 1 Cir. 9/9/14), *writ denied*, 173 So. 3d 1164 (La. App. 1 Cir. 4/23/15).

In *Grace Ranch, LLC v. BP America Production Co.*,[85] the plaintiff, an LLC, purchased property that it alleged was contaminated by operations conducted pursuant to an expired mineral lease that was originally granted in 1944. The Third Circuit Court of Appeal upheld the application of the subsequent purchaser rule to both this claim and to mineral leases in general. The subsequent purchaser rule recognizes the personal nature of a claim for damages in tort or contract. Without an express assignment, that claim remains with the owner at the time the damage occurred. In reaching this decision, the court also expressly considered the extent to which a mineral lease is considered to be a real right under Louisiana law. The court found that Louisiana statutory law holds that a mineral lease creates a real right in favor of the mineral lessee rather than the lessor. This is an explicit rejection of the often-made argument that claims related to a mineral lease run with the land in favor of the lessor or landowner. The court clarified that the real right associated with a mineral lease is held by the mineral lessee who has the right to enter the premises to explore for and produce minerals. Similarly, the corresponding real obligation is imposed on the mineral lessor or surface owner to allow that to occur. The court further rejected the argument that plaintiff had a real right of action based on La. R.S. § 31:11 or La. Civ. Code art. 667. The court found both of those statutes require contemporaneous occupation of the property, which did not exist in this case because the mineral lease expired prior to plaintiff's acquisition of the property. Finally, the court also rejected plaintiff's attempt to obtain assignments of the right of action to avoid application of the subsequent purchaser doctrine. One of the plaintiff's predecessors in title was an entity that dissolved by affidavit under La. R.S. §§ 12:142.1 and 12:250.1. Finding no provision allowing survival of the dissolved corporation's inchoate claims, the court concluded the dissolved predecessor corporation was incapable of assigning claims to plaintiff.

Britt v. Riceland Petroleum Co.,[86] confirmed what had been the practice for many years in relation to the settlement of claims for environmental damage under Act 312, La. R.S. § 30:29. This case involved a settlement between the plaintiff-landowners and two defendants, who agreed to remediate the property to state regulatory standards. Notice and an opportunity to comment on the proposed settlement was given to the Office of Conservation of the Louisiana Department of Natural Resources (LDNR) and to the Attorney General's office. LDNR is the agency charged with overseeing any environmental remediation. After reviewing the proposed settlement, LDNR issued a letter of no objection to the settlement. Plaintiff-landowners then moved for court approval of the settlement, which was granted by the Court. Certain insurers objected after the settlement was approved. They claimed that La. R.S. § 30:29(J) required the trial court to hold a contradictory hearing, determine if remediation is required, and order that the funds be deposited into the court registry. The court read the statute to require a contradictory hearing only if there is an objection. Here, there were no objections or opposition to the settlement. Thus, the court held that all mandatory requirements for approval were satisfied, and the trial court acted well within its authority to approve the settlement at the time.

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[85] 252 So. 3d 546 (La. App. 3 Cir. 7/18/18).

[86] 240 So. 3d 986 (La. App. 3 Cir. 3/7/18), *writ denied*, 243 So. 3d 569 (La. 5/25/2018).

In addition to the developments in legacy litigation, there were a number of noteworthy decisions in other areas of oil and gas law this past year. In *J. Fleet Oil & Gas Corp. v. Chesapeake Louisiana, L.P.*,[87] a dispute arose between the parties to the language of a Participation Agreement that established an Area of Mutual Interest. Plaintiffs contended, among other allegations, that the interest assigned by defendant under the Participation Agreement was a cost-free net revenue interest (NRI) while defendant argued the interest was an overriding royalty interest (ORRI). Plaintiffs also alleged that defendant improperly deducted post-production costs from payments made to plaintiffs. These issues were taken up by the Western District on a motion for summary judgment filed by the defendants. First, the court recognized that the term *overriding royalty* was a technical term of art in the oil and gas industry. The characterization of the interest as such in the Participation Agreement and the definition of the term unequivocally evidenced the parties' intent to create an ORRI. Second, the court determined that the Participation Agreement provided defendants with the right to deduct post-production expenses. At the outset, the court noted that Louisiana law allows the deduction of post-production expenses from lease-royalty payments unless the language of the lease provides otherwise. Looking to the language of the Participation Agreement, the court concluded that the provision stating that the ORRI shall be free of all development, production, and operating expenses made no mention of post-production costs. Thus, in accordance with Louisiana's general rule, the Participation Agreement evidenced an unambiguous intent to share in post-production costs on a pro rata basis.

The Western District also opined on the sufficiency of detail contained in reports provided by an operator to an unleased owner pursuant to La. R.S. §§ 30:103.1 et seq. In *M&N Resources Management, LLC v. Exco Operating Co.*,[88] the court applied the analytical framework set forth by the United States Fifth Circuit in *Brannon Properties, LLC v. Chesapeake Operating, Inc.*,[89] and determined that certain reports sent initially by defendant failed to comply with La. R.S. § 30:103.1 while other later-sent reports were sufficiently detailed under the statute. The early reports sent by defendants only contained six categories of expenses: Leasehold Producing; Intangible Drilling Costs; Lease Operating Expense; Intangible Completion Cost; Lease & Well Equipment; and Lease & Well Surface Equipment. Because these reports contained only a few limited, broad categories of expenses, the court concluded that the reports were similar to the reports deemed insufficient in *Brannon* insofar as they did not provide any detail from which an owner could assess what it was getting for its money. Pursuant to La. R.S. § 30:103.2, the defendant forfeited the right to demand contribution from the unleased owner for the costs of the drilling operations of the well. Noting that the Louisiana Supreme Court had not addressed the scope of the penalty provision, the Western District relied upon the only state appellate court decision, *XXI Oil & Gas, LLC v. Hilcorp Energy Co.*,[90] and concluded that the penalty included the cost of drilling, completing, and equipping the well. However, consistent with *Brannon*, the court concluded that the later-sent reports containing

[87] 2018 WL 1463529 (W.D. La. Mar. 22, 2018).

[88] 2017 WL 8809775 (W.D. La. Dec. 13, 2017).

[89] 514 F. App'x 459 (5th Cir. 2013).

[90] 206 So. 3d 885 (La. App. 3 Cir. 2016).

the requisite level of detail cured defendant's failure to comply with the statute. These later-sent reports, the court reasoned, were sufficiently detailed because the expenses were listed by date, contained references to invoice numbers, were set forth in more specific categories of cost, and vendor names were provided for most of the expenses. Thus, the court concluded these later-sent reports complied with La. R.S. § 30:103.1.

In *Gloria's Ranch, L.L.C. v. Tauren Exploration, Inc.*,[91] the Supreme Court of Louisiana considered whether a mortgagee with credit rights to an oil and gas leasehold interest, along with the oil and gas producing assets, was liable for the failure to furnish an act evidencing the expiration of the lease and the failure to pay royalties. In addition, the court considered whether Mineral Code article 140 provides a lessor with the right to potentially recover unpaid royalties and an additional damage amount of double the unpaid royalties. The Supreme Court of Louisiana agreed with the appellate court that the mortgagee was not an *owner* of the lease under Mineral Code articles 206 and 207 by virtue of assignment. However, the court reversed the holding that the mortgagee was an *owner* of the lease because it controlled the bundle of rights that make up ownership. Looking to the Mineral Code articles relating to granting and transferring mineral leases, the court noted the absence of articles sanctioning ownership under the *control of rights* theory adopted by the appellate court. Moreover, the court recognized that the Mineral Code clearly distinguished between rights of ownership and security rights. Accordingly, the Supreme Court concluded the appellate court erred in finding that a mortgage and a credit agreement effectuated a conveyance of the mineral lease. And as a result, the mortgagee could not be liable for breach of the lease. As to the penalty for unpaid royalties, the court engaged in an exercise of statutory interpretation with the language of Mineral Code article 140 that authorizes a court to award as damages double the amount of royalties due. Based on the foregoing language, the court determined that the legislature intended to allow courts to award up two times the amount of unpaid royalties, not three times the amount.

In *J&L Family, L.L.C. v. BHP Billiton Petroleum Properties (N.A.), L.P.*,[92] the Western District considered whether an unleased mineral owner could recover attorney's fees under La. R.S. §§ 31:212.21 et seq. or La. C.C. art. 1958 for fraud. Both issues were reviewed by the court on defendants' motion for summary judgment. The court reaffirmed *Adams v. Chesapeake Operating Co.*,[93] and concluded that the statute did not apply to unleased mineral owners because such owners were not the purchasers of mineral production payments. Accordingly, plaintiff was barred from recovering attorney's fees under La. R.S. §§ 31:212.21 et seq. The court also rejected plaintiff's argument that La. C.C. art. 1958 provided unleased mineral owners with a right to recover attorney's fees. The court noted that Article 1958 provides for attorney's fees in conjunction with a claim of contract fraud. The court was unwilling to extend the remedies set forth in Article 1958 to the quasi-contractual relationship between an unleased mineral owner and the operator of a well drilled pursuant to a drilling and production unit created by the Commissioner of Conservation.

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[91] 252 So. 3d 431 (La. 6/27/18), *reh'g granted on other grounds,* 251 So. 3d 292 (La. 9/7/18).

[92] 293 F. Supp. 3d 615 (W.D. La. 2018).

[93] 561 F. App'x 322 (5th Cir. 2014).

VII. NEW MEXICO

A. *Judicial Developments*

What constitutes commencement of operations under an AAPL form operating agreement was the issue addressed by the New Mexico Supreme Court in *Enduro Operating LLC v. Echo Production, Inc.*[94] The court ruled that, absent language to the contrary in the operating agreement, the following rules apply to proving whether an operator timely commenced drilling operations: (1) actual drilling is conclusively commencement but is not required; (2) obtaining a drilling permit is not mandatory; (3) activities such as leveling the well location, digging a slush pit, or other good-faith commitment of resources at the drilling site will suffice as evidence of the parties' present intent to diligently drill, and (4) "the off-site commitment of resources, such as entering into an enforceable drilling contract requiring the diligent completion of the well, will also suffice as evidence that the operator actually commenced drilling operations."[95] The operator in that case had not conducted any of the on-site activities described by the court or obtained a drilling permit by the time the contractual commencement deadline expired. However, the case was remanded as there was a material fact in dispute as to whether the operator had signed a drilling contract with a cancellation penalty prior to expiration of the commencement deadline.[96]

In *Anderson Living Trust v. Energen Resources Corp.*,[97] the Tenth Circuit faced class claims for royalty underpayment for some New Mexico and Colorado oil and gas leases in the San Juan Basin. It rejected various theories of royalty underpayment under New Mexico law while agreeing with some of those claims applying Colorado law. Energen paid natural gas royalties to the plaintiff on a netback basis in which it deducted various third-party, post-production costs from its downstream sales price to calculate royalty.[98] First, consistent with prior Circuit authority, the court ruled that New Mexico has not adopted a marketable condition rule.[99] Second, the court ruled that Energen was entitled to deduct from royalty payments the natural gas processors tax that the processor passed through to Energen since the act authorizing the tax did not prohibit pass through to royalty owners.[100] Third, the court addressed Energen's deduction of off-lease fuel consumed by third party service providers when calculating royalty. It reached different results applying the law of New Mexico and Colorado. As to the New Mexico leases, the court ruled that the deduction of fuel consumed off-lease was appropriate as New Mexico courts had taken a broad view of free use provisions.[101] As to the Colorado properties, the court found that the leases did not

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[94] 413 P.3d 866 (N.M. 2018).

[95] *Id*. at 872–73.

[96] *Id*. at 874.

[97] 886 F.3d 826 (10th Cir. 2018).

[98] *Id*. at 832.

[99] *Id*. at 834–39 (citing Elliott Indus. Ltd. P'ship v. BP Am. Prod. Co., 407 F.3d 1091 (10th Cir. 2005)).

[100] *Id.* at 840–42 (citing N.M. Stat. Ann. § 7-33-4(A) (1999); Exxon Corp. v. Eagerton, 462 U.S. 176 (1983)).

[101] *Id.* at 842–47 (primarily citing ConocoPhillips Co. v. Lyons, 299 P.3d 844 (N.M. 2012), and Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496 (N.D. 2009)).

expressly provide for the deduction of off-lease fuel to render the gas marketable.[102]

In a separate case, involving the same plaintiff, the Tenth Circuit also addressed the appealability of a denial of class certification in a royalty underpayment case.[103] The court held a denial of class certification was not a final appealable order under the circumstances of this case.

A federal district judge addressed an oil and gas company's rights to recover time-barred claims using equitable recoupment in *SDF, L.L.C. v. ConocoPhillips Co.*[104] The case involved an overriding royalty interest which, by its terms, was not payable if the subject wells did not produce, on average, more than 500 Mcf per day. The operator stopped paying the overriding royalty in 2016 and began recouping for overpayments dating back to 1990.[105] The operator sought to dismiss a claim that the self-help nature of the recoupment was an attempt to illegally evade the statute of limitations.[106] The district court found that there was no indication that New Mexico courts would overrule case law that permitted offensive use of recoupment.[107]

The BLM's authority to order another casing integrity test (CIT) for a well that had been temporarily abandoned for over 25 years was the subject of *Cibola Energy Corp. v. U.S. Dep't of the Interior*.[108] Though the actual facts are more convoluted, basically Cibola operated a marginal well located more than 10 miles from the nearest pipeline that had been granted temporarily abandoned (TA) status by the BLM. In 2002, 12 years after the well was completed, Cibola performed a successful CIT witnessed by a BLM representative. In 2011, upon another request by Cibola for TA status, the local BLM office ordered a new CIT test. Cibola objected on the grounds that the well had been continually shut in so that there was no rational basis to order a new CIT test. The local BLM ordered a new test and Cibola appealed and lost at both the State Director and Interior Board of Land Appeals levels.[109] Noting the heavy burden of proving the agency determination to be arbitrary and capricious, the district court sustained the agency decision as it was clear that the agency had considered Cibola's arguments that it was impossible that the conditions of the casing had not changed and "Cibola does not point to evidence in the record that changes in the [w]ell in twenty years are impossible."[110]

B. Administrative Developments

The New Mexico Oil Conservation Commission adopted an extensive overhaul to the rules related to horizontal wells in an Order dated May 22, 2018.[111]

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[102] *Id.* at 848–49 (primarily citing Garman v. Conoco, Inc., 886 P.2d 652 (Colo. 1994)).

[103] Anderson Living Trust v. WPX Energy Production, LLC, 904 F.3d 1135 (10th Cir. 2018).

[104] 2018 WL 1183360 (D.N.M. Mar. 6, 2018).

[105] *Id.* at *2.

[106] *Id.* at *3. Although not discussed, the longest possible statute of limitations in New Mexico is the six-year statute of limitations for breach of written contract. N.M. Stat. Ann. 1978, § 37-1-3.

[107] *Id.* (citing City of Carlsbad v. Grace, 966 P.2d 1178, 1183–87 (N.M. Ct. App. 1998)).

[108] 2018 WL 2337137 (D.N.M. May 23, 2018).

[109] *Id.* at *2.

[110] *Id.* at *6.

[111] Order No. R-14689 (with a copy of the red-lined changes to the rules attached), http://www.emnrd.state.nm.us/OCD/documents/CommissionOrder.pdf.

The changes to the rules are substantial. One principal change is to reduce the setback requirements. For initial and last take points, the distance to the outer boundary of the spacing unit is reduced to 100 feet in horizontal oil wells and 330 feet in horizontal gas wells.[112] The perpendicular setback from the outer boundary of the spacing unit is now 330 feet for horizontal oil wells and 660 feet for horizontal gas wells.[113] The new rules also have the effect of allowing the creation of horizontal spacing units that are not traditional "stand-up" or "lay-down" in shape.[114] The new rules also provide for a stream-lined procedure for pooling interests for "infill horizontal wells."[115]

In a July 24, 2018 Order,[116] the Commission repealed the former rules regarding spill and release and adopted new rules on those topics effective August 14, 2018.[117] The new spill rules created specific criteria for an operator's initial response to a spill; imposed requirements for site assessment, characterization and delineation of the spill; imposed requirements for a remediation plan; imposed obligations for restoration, reclamation and re-vegetation; made provisions for applications for variances from the rule; and imposed new enforcement standards.[118]

VIII. OHIO

A. Judicial Developments

Despite a lull in drilling activity, the Supreme Court of Ohio remained engaged with oil and gas issues in 2018. Several of the court's decisions involved potential threats to the sole and exclusive nature of the Division of Oil and Gas Resources Management's authority over oil and gas operations in Ohio. As background, environmental activist groups (some from out-of-state) repeatedly sought to put to the general vote, local governmental charter amendments that would severely hamper—and at times eliminate outright—oil and gas development in the area. In each of these cases—*State ex rel. Khumprakob v. Mahoning County Board of Elections*,[119] *State ex rel. Bolzenius v. Preisse*,[120] and *State ex rel. Twitchell v. Saferin*[121]—appellants asked the court to determine whether a county board of election properly excluded a community *bill of rights* from the ballot. While in both *Bolzenius* and *Twitchell*, the court found that the board had properly excluded the charter amendments, in *Khumprakob*, the court granted the writ directing the board to place the amendments on the ballot. These efforts are likely to continue to be an issue in Ohio.

In *Alford v. Collins-McGregor Operating Co.*,[122] the Supreme Court held that Ohio does not recognize an implied covenant of further exploration apart from the

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[112] N.M. Code R. § 19.15.16.15(C)(1)(b).

[113] *Id*. at (C)(1)(a).

[114] *Id*. at (B)(1)–(4).

[115] *Id*. at (B)(9)(b).

[116] Order No. R-14751, http://www.emnrd.state.nm.us/OCD/documents/Florene.pdf.

[117] N.M. Code R. § 19.15.29.

[118] Order No. R-14751 at ¶ 9.

[119] 2018-Ohio-1602, 109 N.E.3d 1184.

[120] 2018-Ohio-3708, 119 N.E.3d 358.

[121] 2018-Ohio-3829, 119 N.E.3d 365.

[122] 2018-Ohio-8, 95 N.E.3d 382.

implied covenant of reasonable development. In reaching its decision, the court often quoted with approval the Oklahoma Supreme Court, noting the importance of the profit motive for all parties: "[T]he issue is whether a prudent operator would further develop the land 'having due consideration for the interest of both the lessee and lessor, considering all factors, including what is known about the market, the geology and adjoining activity.'"[123] This decision establishes that compliance with an implied development covenant in Ohio depends, at least in part, on the anticipated economics of that development.

The supreme court addressed whether independent landmen must obtain Ohio real estate licenses to negotiate oil and gas leases in *Dundics v. Eric Petroleum Corp*.[124] Noting first that Ohio law prohibited anyone from acting as a real-estate broker without a license, the court observed that activities requiring a license included "negotiating the lease of real estate, holding one's self out as engaged in the business of leasing real estate, and 'the procuring of prospects or the negotiation of any transaction . . . which does or is calculated to result in' the lease of real estate."[125] After reaffirming that oil and gas leases create an interest in real estate, the court found "[t]here is simply no exception in the statutes governing real-estate-broker licenses for oil-and-gas leases or oil-and-gas land professionals."[126]

Brought as a mandamus action, the complaint in *State ex rel. Kerns v. Simmers*[127] asked the court to find that a unit order issued under Ohio Rev. Code § 1509.28 required compliance with Ohio appropriations law as a taking under Ohio's Constitution. Without addressing the takings issue, the court dismissed the petition for the writ due to the appellate proceedings available to plaintiffs. "A finding that Ohio Rev. Code § 1509.28 was unconstitutional [on appeal] would have invalidated the chief's order. No taking would have occurred, so there would have been no need for a writ compelling appropriation proceedings."[128]

Ohio's appellate courts also heard a number of oil and gas related cases this year. One of the primary topics was production in paying quantities. The Fifth Appellate District addressed the type of evidence that a lessee could use to support a paying quantities claim in *Browne v. Artex Oil Co*.[129] The lessors argued that the use of production records and affidavit testimony on summary judgment was insufficient, and that only "run tickets" and "legal tender of oil" were permissible.[130] The appellate court disagreed, noting, "[e]xamples of proof of production include royalty payments to lessor, lessee's accountant's charts, and affidavits."[131]

The Seventh Appellate District also addressed the types of payments to be included as operating costs in a paying quantities analysis in *Neuhart v.*

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[123] *Id*. at 308.

[124] 2018-Ohio-3826, 120 N.E.3d 758.

[125] *Id*. at 761.

[126] *Id*.

[127] 2018-Ohio-256, 101 N.E.3d 430.

[128] *Id*. at 434.

[129] 2018-Ohio-3746, 116 N.E.3d 687 (5th Dist.).

[130] *Id*. at 693.

[131] *Id*.

Transatlantic Energy Corp.[132] The issue, according to the court, is whether the payments are "directly related to the production of oil and gas."[133] The court found that an administrative fee related to overhead costs, as well as gathering and compression costs, were not directly related to the production of oil and gas and therefore should not be included in the analysis.[134] Nor should the costs related to a pump replacement be included.[135] The court did include income and property taxes, pumping costs, royalties, and chart integration fees. In all, the court concluded that the wells were producing in paying quantities.[136]

Ohio courts also continued to hear cases involving pooling and unitization issues. In *American Energy-Utica, LLC v. Fuller*,[137] the Fifth Appellate District held that the lessee's application for a unit order under Ohio's compulsory unitization law, R.C. 1509.28, violated the Retroactivity Clause of the Ohio Constitution. The court held so in the context of a handwritten lease provision stating "unitization by written agreement only!" in a lease that post-dated the unitization statute's effective date. The lessee has asked the supreme court to review the appellate court's decision. As of this writing, the court has not ruled on the lessee's request.

In *Kerns v. Chesapeake Exploration, L.L.C.*, the Northern District of Ohio addressed whether the State of Ohio's issuance of a unit order under Ohio Rev. Code § 1509.28 was a taking in violation of the Fifth and Fourteenth Amendments to the U.S. Constitution and 42 U.S.C. § 1983.[138] The district court held that it was not, finding (i) that the producer was not a state actor for purposes of constitutional responsibility (reasoning that filing an application for a unit order, and drilling and producing a well, "do not demonstrate a 'sufficiently close nexus' between [the producer] and the state such that [the producer's] conduct could be fairly attributed to the state."); and (ii) that, contrary to plaintiffs' claims, "the statutory unitization procedure set forth in R.C. § 1509.28 operates to protect the correlative rights of landowners, including plaintiffs, and it was passed as a valid exercise of Ohio's police power."[139] In reaching its conclusion, the court affirmed long-standing precedent that unitization and pooling statutes are valid, constitutional exercises of the state's police power for the protection of correlative rights, and found that this precedent applies to horizontal development. The court also rejected the plaintiffs' argument that a *per se* taking had occurred because the lessee's operations injected water, sand, and chemicals into the plaintiffs' property (finding that a landowner's property rights in the subsurface are limited and not absolute).[140]

Several courts also addressed Ohio's Dormant Mineral Act (DMA).[141] In *Shilts v. Beardmore*,[142] the Seventh Appellate District analyzed whether a

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[132] 2018-Ohio-4099, 2018 WL 4913821 (7th Dist.).

[133] *Id*. at *5.

[134] *Id*.

[135] *Id*. at *7.

[136] *Id*. at *9.

[137] 2018-Ohio-3250, 2018 WL 3868119 (5th Dist.).

[138] No. 5:18-cv-00389, 2018 WL 2952662 (N.D. Ohio June 13, 2018), *aff'd*, No. 18-3636 (6th Cir. Feb. 4, 2019), *petition for cert. filed*, No. 18-1278 (Apr. 3, 2019).

[139] *Id*. at *5, 12.

[140] *Id*. at *11–12.

[141] Ohio Rev. Code §§ 5301.56 et seq.

surface owner complied with the notice requirement of the 2006 version of the DMA. One of the central issues on appeal was whether the statute required the surface owner to try serving his notice of abandonment by certified mail *prior* to serving his notice of abandonment by publication. The court held that service by publication was sufficient because the surface owner established that he had exercised reasonable efforts to locate the unknown heirs of the record owners of the dormant mineral interest.[143] The surface owner searched the records of the county recorder's office and probate court where the subject land is located. He also searched the records of the Ohio Department of Natural Resources, Division of Oil and Gas Resources Management and conducted an online search. None of these sources revealed the names and addresses of the unknown heirs. Because "it became clear that service [of the notice of abandonment] could not be completed by certified mail," service by publication was sufficient. As the court found, "[i]t would be absurd to absolutely require an attempt at notice by certified mail when a reasonable search fails to reveal addresses or even the names of potential heirs who must be served."[144]

In *Jefferis Real Estate Oil & Gas Holdings, LLC v. Schaffner Law Offices, L.P.A.*,[145] defendants appealed the trial court's decision finding the plaintiffs successfully abandoned certain severed mineral rights under the 2006 version of the DMA. The defendants disputed the abandonment, pointing to the preservation notice they filed within 60 days after plaintiffs filed their notice of abandonment. Plaintiffs claimed that the preservation notice was invalid because defendants, who were heirs of the record mineral holder, were not "on record" heirs. The court looked to the express language of the DMA and found that it defines "record holder" as "any person who derives the person's rights from, or has a common source with, the record holder . . . ."[146] Because defendants derived their rights from the "record holder," the court found that defendants' preservation notice was valid and reversed the trial court's abandonment of the minerals.[147]

Deed interpretation was the central issue in *Mid-Ohio Coal Co. v. Brown*.[148] The Fifth Appellate District found that the grantees received oil and gas rights in an 1882 deed conveying all right, title, and interest in the property, "but reserving to said grantors their heirs and assigns all the surface of said land including stone and water privileges on or under the same excepting stone coal."[149] The court reasoned that "[a] grant without qualifying or limiting words of the minerals underlying certain reason estate will include oil and gas. The . . . deed contains no such qualifying language, so we must construe the deed to include oil and gas."[150]

Ohio's federal courts addressed several times class certification issues in the context of royalty disputes. Of particular note, in *Lutz v. Chesapeake Appalachia,*

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[142] 2018-Ohio-863, 2018 WL 1225745 (7th Dist.).

[143] *Id*. at *4.

[144] *Id*.

[145] 2018-Ohio-3733, 109 N.E.3d 1265 (7th Dist.).

[146] *Id*. at 1274.

[147] *Id*.

[148] 2018-Ohio-1934, 113 N.E.3d 133 (5th Dist.).

[149] *Id*. at 137.

[150] *Id*. at 139.

L.L.C.,[151] the Northern District of Ohio denied class certification in a matter involving claims that the producer had paid royalties on an incorrect unit price and made impermissible deductions from royalty payments where the leases did not contain "at the well" language. The court found that the plaintiffs had failed to establish the commonality, typicality, and predominance needed for class certification. Among other reasons, the plaintiffs failed "to account for the notable variations in the language of the leases, [and failed] to refute defendant's interrogatory answers regarding the variation in the method of calculating royalties."[152]

Lastly, the Northern District of Ohio, in *Baatz v. Columbia Gas Transmission, LLC*,[153] dismissed plaintiffs' claims that Columbia Gas's use of an underground storage field constituted a trespass. Columbia Gas used a gas storage field in Medina County under a certificate from the Federal Power Commission but did not seek gas storage easements from the plaintiffs-landowners until 2014. In dismissing plaintiffs' claims, the court held that plaintiffs failed to prove actual damage because they never used the formation where Columbia stored its gas, nor did plaintiffs plan to use this property.[154]

IX. OKLAHOMA

A. Judicial Developments

The final appellate decision in the long-pending litigation in *Pummill v. Hancock Exploration LLC*[155] (*Pummill II*) involved an appeal of the district court's declaratory judgment on the merits, following a bench trial, rejecting the oil and gas-lessee defendants' contention that they were allowed to proportionately charge certain expenses against the plaintiffs' royalty interest payments. The court of appeals observed that "[t]he question of consequence on appeal involves defendants' challenge to the trial court's determination of when the natural gas at issue here became a 'marketable product.'"[156] In affirming the district court's judgment at the conclusion of the trial in favor of Pummill, the court held in part as follows: The court initially observed that "[t]he issue of when natural gas first becomes 'marketable' has been the source of much contention and consternation in both legal and oil and gas circles for several years."[157]

In summarizing certain legal principles, the court noted that a lessee has an implied duty to obtain a *marketable product*, including the cost of preparing the gas for market and getting the gas to the place of sale in marketable form. As a general rule, the lessee may not deduct from royalty payments the costs of gathering, transportation, compression, dehydration, or blending if those costs are required to create a marketable product, unless the lease provides otherwise. The lessee's obligation is not unlimited. In *Mittelstaedt,* where the court considered a

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[151] No. 4:09-cv-02256, 2018 WL 4853328 (N.D. Ohio Oct. 5, 2018), *appeal docketed*, No. 19-3315 (6th Cir. Apr. 10, 2019).

[152] *Id*. at *6.

[153] 295 F. Supp. 3d 776 (N.D. Ohio 2018).

[154] *Id*. at 758.

[155] 2018 OK CIV APP 48, 419 P.3d 1268.

[156] *Id.* ¶ 2. The "marketable product" standard was recognized in the landmark Oklahoma Supreme Court decision in *Mittelstaedt v. Santa Fe Minerals, Inc.*, 1998 OK 7, 954 P.2d 1203.

[157] *Pummill II*, 2018 OK CIV APP 48, ¶ 25.

gross proceeds lease, the court recognized that, although expenses to obtain a marketable product are not chargeable against royalty, reasonable post-production expenses might be applied if the expenses involve enhancing the value of an already marketable product, and the lessee shows that the expenditures resulted in a proportionate increase in royalty revenue. Unfortunately, the court in *Mittelstaedt* did not define the meaning of *marketable product*, nor has it done so since.[158] The court of appeals agreed with the trial court that the defendants failed to sustain their burden of proving that they were entitled to deduct the costs at issue, and affirmed the district court's ruling in favor of the *Pummill* plaintiffs.

In *Whisenant v. Strat Land Exploration Co.*,[159] the plaintiff Whisenant asserted that Strat Land failed to pay the royalty amounts that were due on its production, both as operator and non-operator, from Oklahoma wells. The state district court granted Whisenant's motion and certified a royalty owner class under 12 Okla. Stat. § 2023(B)(3).[160] Strat Land appealed. The Oklahoma Court of Appeals found that class certification was not appropriate in this case "because a 'highly individualized' review of the facts pertaining to each of the numerous wells is necessary."[161] The court held that the issue of liability and "the appropriate damages (if any) to be awarded, to each of the royalty owners in the proposed class is not susceptible to class-wide resolution 'in one stroke.'"[162] Common questions of law or fact did not predominate in this case.

In reaching those conclusions, the court discussed in detail the impact that the landmark decision in *Mittelstaedt v. Santa Fe Minerals, Inc.*[163] and the "marketable product" standard recognized in that decision, would have on the determination of the class claims. The court noted that "highly individualized and fact-intensive review of each Class Members' claim would be necessary to determine if [the defendant] underpaid oil or gas royalties."[164] Additional considerations supporting the reversal of class certification are described by the court in the lengthy opinion. In a special concurring opinion, added by Judge Rapp to the majority opinion of Presiding Judge Barnes, the Judge discussed the way in which the determination of the amount of payment due each royalty owner, and when the payment is due, "affects the ability to sustain class actions based on numerous individual wells spaced over a large geographic area."[165]

The case of *Hall v. Galmor*,[166] presented the appeal of the trial court's judgment, after a bench trial, denying the appellants' petition to cancel oil and gas leases of the appellee. The opinion in this case is 36 pages in length, so only certain of the underlying facts and rulings of the court are described in this short summery. Here, Hall appealed the adverse judgment of the trial court to the Oklahoma Supreme Court, which retained the appeal. Hall argued on appeal that,

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[158] *Id.* ¶¶ 26, 27, 28.

[159] 2018 OK CIV APP 65, 429 P.3d 703.

[160] 2018 OK CIV APP 65, ¶ 5.

[161] *Id.* ¶ 11.

[162] *Id.*

[163] 1998 OK 7, 954 P.2d 1203.

[164] *Whisenant*, 2018 OK CIV APP 65, ¶ 15 (alteration in original) (quoting Strack v. Cont'l Res., Inc., 2017 OK CIV APP 53, ¶ 32, 405 P.3d 131).

[165] *Id.*, specially concurring opinion, ¶ 2.

[166] 2018 OK 59, 427 P.3d 1052.

in order for a well to be "capable" of producing in paying quantities, "the well must be maintained in turn-key condition such that it will produce in paying quantities immediately upon being turned 'on.'"[167] The court found that this proposed definition was first announced by the Texas Court of Appeals in a 1993 decision.[168] The court affirmed the trial court's rejection of Hall's proposal that Oklahoma courts adopt the Texas rule and require operators to continually maintain their shut-in wells in turn-key condition.

Hall further contended that the *cessation of production clauses* of the oil and gas leases resulted in the termination of the leases. However, citing *Pack v. Santa Fe Minerals, Inc.*,[169] the court found that a well's capability to produce in paying quantities will satisfy both the habendum clause and the cessation of production clause of the lease, and the cessation of production clause is only triggered where a well has become *incapable* of commercial production.[170] Hall further argued that the above outcomes would allow a lessee to "sit" on a well capable of production in paying quantities, without any actual production, for an indefinite time period, thereby rendering the cessation of production time limits of no effect. The court observed that the lessor could make a written demand for compliance with the implied covenant to market, which would force the lessee to commence actual production of the gas out of the ground and market the production or else face the possibility of a lease cancellation.[171]

The court found that the trial court addressed Hall's claims for breach of the express lease terms by finding that the wells were capable of commercial production, and then proceeded to assess whether the leases could be cancelled for breach of any other express or implied provisions or covenants. The trial court correctly found that the leases could not be canceled due to the failure to satisfy the prerequisite for a prior *demand to market* made by the lessors.[172] The court remanded the case, based on the above rulings and others, with instructions to conduct further proceedings in a manner consistent with the court's opinion.

In *American Star Energy & Minerals Corp. v. Armor Petroleum, Inc.*,[173] Armor appealed from the trial court's judgment in favor of the plaintiff, American Star, in this breach of contract action. The key controversy in this case was whether the defendant-lessees were obligated, under a provision of an assignment, to notify American Star of the proposal and plan to plug the subject well, and to also offer American Star the opportunity to purchase defendants' interests in lieu of plugging the well. The well at issue was located within the Rice Morrow Sand Formation unitized field established under 52 Okla. Stat. §§ 287.1 et seq. The Plan of Unitization became effective December 1, 1994. At some point years later, the decision was made to plug the well. The Unit sent notice of such intent to all lessees of the Rice Morrow formation. The well was plugged and abandoned on

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[167] *Id.* ¶ 23.

[168] Hydrocarbon Mgmt., Inc. v. Tracker Exploration, Inc., 861 S.W.2d 427 (Tex. App. 1993). The Texas Supreme Court is cited as having later approved that definition of "capability" in its decision in *Anadarko Petroleum Corp. v. Thompson*, 94 S.W.3d 550, 558 (Tex. 2002).

[169] 869 P.2d 323, 1994 OK 23.

[170] *Id.* ¶ 37.

[171] *Id.* ¶ 39.

[172] *Id.* ¶ 42.

[173] 89 O.B.J. 548 (Okla. App. 2018 - #115,490) (Not for Publication).

December 3, 2009. The defendants, who were lessees of the Unit and successors to the obligations under the assignment, did not notify American Star of the impending plugging of the well or afford American Star the opportunity to exercise its purchase option prior to the closure of the well.

American Star filed this suit seeking damages for the cost of drilling a new well for purposes of drilling into a new formation. Following a bench trial, the trial court held for American Star, finding the contractual obligations contained in the assignment were continuing, assumed by the defendants, and did not conflict with the unitization plan or statutes. American Star was awarded $200,000 in damages plus statutory interest. The defendants appealed, and the court of appeals stated in part as follows: The appellate court agreed that the Unit had no obligation to notify American Star of its intent to plug the well. The Unit operator was only required to provide notice to *lessees* of the subject tract, and American Star was not a lessee. However, the defendants were obligated to provide notice to American Star pursuant to the terms of their assignment. Contrary to their assertion, this contractual requirement remained enforceable and, in no manner, conflicted with the notice requirements of the plan of unitization, or of the unitization statutes in general.

The unpublished decision of the Oklahoma Court of Appeals in *Hobson v. Cimarex Energy Co.*,[174] presented the issue of whether the Oklahoma Surface Damages Act[175] applied to the vested remainder interest owned by Hobson in the surface of the subject property. Cimarex had reached a surface damages settlement with the life tenant. But when Hobson sued Cimarex claiming compensation under the Act based on his remainder interest, Cimarex argued that the owner of a future interest did not qualify as a *surface owner* under the Act. Cimarex also asserted that Hobson's remedy, if any, was against the life tenant. The trial court ruled in favor of Cimarex, agreeing with its first contention above. Hobson appealed.

The court of appeal observed that the Act lacks clarity and specificity regarding what constitutes a *surface owner* and an *owner* for purposes of awarding compensation. Rejecting Cimarex's argument that Hobson was not entitled to compensation under the Act, the court stated that, as a vested remainderman, Hobson had a marketable interest in the property that could be adversely affected by the drilling operation, and that he was also entitled to have the property restored. The issue in the case was not *rents and profits* but, instead, damages measured by the loss of market value or the cost of restoration. The court found that Hobson was an *owner* under the Act. Accordingly, the trial court's judgment was reversed and the cause remanded for further proceedings.

In *Oklahoma Oil & Gas Ass'n v. Kingfisher County Commissioners*,[176] the Oklahoma Supreme Court issued its order on rehearing[177] and found Resolution No. 23, issued by the respondent commissioners, was beyond their authority and was void. Resolution No. 23, issued on April 9, 2018, advised that the commissioners banned the use of produced water (*e.g.,* salt water, oil field brine, waste oil, basic sediment, mud) in temporary lines. The commissioners further adopted pipeline crossing permit documents that again indicated that the county

[174] 89 O.B.J. 1101 (Okla. App. 2018 - #116,721) (Not for Publication).

[175] 52 Okla. Stat. §§ 318.2–.9.

[176] No. 117,303, original action before the Oklahoma Supreme Court.

[177] *Id.* Order issued on rehearing Dec. 17, 2018, *reh'g denied* Jan. 22, 2019.

did not permit the use of produced water in temporary lines. The court held that 52 Okla. Stat. § 137.1 did not authorize the county to enact Resolution No. 23. Among other reasons for that finding, the court observed that the resolution was "void as being inconsistent with 52 O.S. Supp.2017 § 139(A), (B)(1)(i) and with the Corporation Commission's regulation found in section 165:10-7-24 of the Oklahoma Administrative Code."[178] The court concluded that the Corporation Commission is the governmental body that has exclusive jurisdiction to enact such a regulation.

In very brief form, the decision of the Tenth Circuit Court of Appeals in *Chieftain Royalty Co. v. SM Energy Co.*[179] discussed the controlling legal principles to be applied in reviewing the attorney's fees and incentive awards approved by the district court in connection with the approval of a class action settlement. The ruling of the district court on the attorney's fees and incentive award was reversed and the case was remanded for further proceedings adhering to the guidance provided by the appellate court.

Hall v. Conoco, Inc.[180] involved a lawsuit against the operator of a refinery located near the plaintiff's childhood home. The Tenth Circuit affirmed the district court's exclusion of testimony from two of the plaintiff's experts and its grant of summary judgment to the Conoco defendants based upon the resulting lack of the expert testimony needed to sustain the plaintiff's evidentiary burden.

In *Charles B. and Kathleen J. Wheeler Trust v. Slawson Exploration, Inc.*,[181] the defendants appealed the trial court's award of attorney's fees and costs to the plaintiff in an action for breach of contract. The contract involved was an oil and gas lease. The court reviewed and rejected the theories for recovery of fees and costs urged by the plaintiff. As to plaintiff's arguments under the Production Revenue Standards Act,[182] the court found that the plaintiffs' petition did not assert a claim under the PRSA. The court reversed the trial court and denied the request for fees and costs.

For a lawsuit addressing a *series* of complex disputes arising from informal oil and gas dealings and related tort claims among oil and gas entities and individuals, see *Online Oil, Inc. v. CO&G Production Group, LLC*.[183]

B. Administrative Developments

Documents filed in the rulemakings referred to below can be viewed on the Oklahoma Corporation Commission's (Commission's) website at www.occeweb.com. Amendments to Title 165, Chapter 10 of the Oklahoma Administrative Code (OAC), which comprises the Commission's Oil & Gas Conservation Rules, were addressed in Cause RM No. 201800002. Following is a brief summary of certain of the amendments which became effective on September 14, 2018:

OAC 165:10-1-4 was amended to update the list of effective dates for OAC 165:10 rulemakings; OAC 165:10-1-7 to update the list of Oil and Gas

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[178] *See* 52 Okla. Stat. § 137.1.

[179] 888 F.3d 455 (10th Cir. 2017) (amended Apr. 11, 2018).

[180] 886 F.3d 1308, 1318 (10th Cir. 2018).

[181] 89 O.B.J. 97 (Okla. App. 2018 - #115,541) (Not for Publication).

[182] 52 Okla. Stat. § 570.14.

[183] 218 OK CIV APP 1, 419 P.3d 337.

Conservation Division prescribed forms, to delete form(s) and to add new form(s); OAC 165:10-3-1 regarding permits to drill wells; OAC 165:10-3-10 concerning hydraulic fracturing operations; OAC 165:10-3-17 with respect to well site and surface facilities; OAC 165:10-3-26 regarding well logs; OAC 165:10-3-28 concerning horizontal drilling in accordance with 52 O.S. § 87.1 *et seq.* and amendments thereto in Enrolled Senate Bill No. 867 (2017); OAC 165:10-3-39 with respect to commingling of production; OAC 165:10-5-6 regarding testing and monitoring requirements for enhanced recovery injection wells and disposal wells; OAC 165:10-5-7 concerning monitoring and reporting requirements for enhanced recovery injection wells, disposal wells and storage wells; OAC 165:10-5-15 with respect to reporting requirements for simultaneous injection wells; OAC 165:10-7-2 regarding administration and enforcement of rules; OAC 165:10-7-7 concerning informal complaints pertaining to alleged violations of Commission orders or OAC 165:10, and OAC 165:10-7-16 with respect to use of noncommercial pits.

In addition, OAC 165:10-7-17 was amended regarding surface discharge of fluids; OAC 165:10-7-19 concerning land application of water-based fluids from earthen pits, tanks and pipeline construction; OAC 165:10-7-22 with respect to permits for County Commissioners to apply waste oil, waste oil residue or crude oil contaminated soil to streets and roads; OAC 165:10-7-26 regarding land application of contaminated soils and petroleum hydrocarbon based drill cuttings; OAC 165:10-7-27 concerning application of waste oil, waste oil residue or crude oil contaminated soil by oil and gas operators and pipeline companies to lease roads, pipeline service and tank farm roads, well locations and production sites; OAC 165:10-7-28 with respect to application of freshwater drill cuttings by County Commissioners to streets and roads; OAC 165:10-7-29 regarding application of freshwater drill cuttings by oil and gas operators to private access areas, well locations and production sites; OAC 165:10-7-31 concerning stratigraphic operations; OAC 165:10-7-33 with respect to truck wash pits; OAC 165:10-9-1 regarding operation of commercial pits; OAC 165:10-9-2 concerning commercial soil farming; OAC 165:10-9-3 with respect to commercial disposal well surface facilities; OAC 165:10-9-4 regarding operation of commercial recycling facilities, and OAC 165:10-11-6 concerning plugging and plugging back procedures for wells.

Amendments to Title 165, Chapter 5 of the Oklahoma Administrative Code, which comprises the Commission's Rules of Practice, were addressed in Cause RM No. 201800001. Following is a brief summary of certain of the amendments which became effective on October 1, 2018:

OAC 165:5-1-3 was amended regarding definitions; OAC 165:5-1-4 concerning telephonic communication service and filings with the Court Clerk; OAC 165:5-1-5 with respect to filing of documents; OAC 165:5-1-9 regarding telephonic and videoconferencing testimony; OAC 165:5-3-1 concerning fees, including, but not limited to, addition of provisions regarding returned payments and changes to Oil and Gas Conservation Division and Transportation Division fees; OAC 165:5-3-2 with respect to Petroleum Storage Tank Division (PSTD) fees; OAC 165:5-5-1 regarding dockets; OAC 165:5-7-6 concerning establishment of drilling and spacing units in accordance with 52 Okla. Stat. §§ 87.1 et seq. and amendments thereto in Enrolled Senate Bill No. 867 (2017), and to provide that API numbers for well(s) be included in applications and orders; OAC 165:5-7-6.1 in accordance with 52 Okla. Stat. §§ 87.1 et seq. and amendments thereto in

Enrolled Senate Bill No. 867 (2017) with respect to horizontal well unitization for targeted reservoirs; OAC 165:5-7-6.2 in accordance with 52 Okla. Stat. §§ 87.1 et seq. and amendments thereto in Enrolled Senate Bill No. 867 (2017) regarding multiunit horizontal wells in targeted reservoirs; OAC 165:5-7-7 concerning pooling, and OAC 165:5-7-11 with respect to change of operator under forced pooling, location exception and increased density orders.

In addition, OAC 165:5-7-12 was amended regarding determination of well allowables; OAC 165:5-7-33 concerning extension of time for closure of noncommercial pits; OAC 165:5-7-34 with respect to waiver of noncommercial pit closure requirements; OAC 165:5-7-35 regarding applications for operation of commercial pits, commercial soil farming sites and commercial recycling facilities; OAC 165:5-9-2 concerning subsequent pleadings; OAC 165:5-9-6 with respect to continuances; OAC 165:5-13-2 regarding setting of causes; OAC 165:5-13-5 concerning exceptions to reports of Administrative Law Judges; OAC 165:5-17-5 with respect to appeals; OAC 165:5-19-1 regarding contempt procedures; OAC 165:5-21-3 concerning application and notice requirements for PSTD cases; OAC 165:5-21-3.1 with respect to applications for variances to PSTD rules; OAC 165:5-23-3 regarding informal resolution of natural gas gathering disputes; and Appendix D concerning a form for notice of application for waiver of pit closure was revoked and a new Appendix D enacted to change the form for notice of application for waiver of pit closure.

X. PENNSYLVANIA

A. Legislative Developments

The Pennsylvania House of Representatives passed House Bill 2154, which establishes the Conventional Oil and Gas Wells Act to restore regulatory provisions of the Oil and Gas Act of 1984 and provide a framework specific to conventional wells and well sites. The reason for House Bill 2154 is that both conventional and unconventional wells are currently permitted with the same regulatory requirements under Act 13 of 2012. House Bill 2154 establishes several new chapters to address conventional well drilling activities and related issues, such as permitting and siting requirements, protection of groundwater and water sources, well plugging requirements, and enforcement and funding provisions. It would also require the Department of Environmental Protection (DEP) to adopt regulations to establish the various requirements and protections related to conventional gas drilling activities. House Bill 2154 states that the provisions of Title 58, relating to oil and gas, are replaced insofar as they relate to conventional wells. The companion bill in the Pennsylvania Senate, Senate Bill 1088, was referred to the Environmental Resources and Energy Committee on March 19, 2018.

B. Judicial Developments

In *Lasher v. Statoil USA Onshore Properties Inc.*,[184] the plaintiff alleged that Statoil miscalculated royalties owed from the sale of gas underlying the plaintiff's property. Specifically, the plaintiff argued that by transferring gas from the property to an affiliate company, Statoil established a scheme whereby it was able

[184] No. 3:17-cv-00914, 2018 WL 1524881 (M.D. Pa. Mar. 27, 2018).

to pay reduced royalty payments to landowners like the plaintiff while significantly marking up the extracted gas to end users, thereby breaching the lease terms.[185] The case was remanded to state court because Statoil failed to meet its burden that it had met the amount in controversy necessary for removal.[186] It is worth noting that in *Canfield v. Statoil USA Onshore Properties, Inc.*,[187] the court held that Statoil's sale to an affiliate did not constitute an express breach where no provision in the lease required Statoil to make royalty payments based on an arm's-length sale or sale to a non-affiliate.

In *Jesmar Energy, Inc. v. Range Resources Appalachia, LLC*,[188] Jesmar assigned Rice Drilling an oil and gas lease in exchange for an overriding royalty interest.[189] The lease contained an arbitration provision and the assignment contained language holding successors to the "terms, covenants, and conditions" of the original lease.[190] Rice Energy subsequently conveyed the assignment to Range Resources.[191] Jesmar, the original lessor, filed suit arguing that Range Resources had breached the assignment clause by paying only part of the overriding royalty and improperly deducting processing costs.[192] Range Resources filed a motion to dismiss or stay pending arbitration since the lease contained an arbitration clause.[193] Jesmar countered that there was no intent by Rice Drilling and Range Resources to incorporate the terms of the original lease, including the arbitration clause, in the assignment.[194] The court agreed, relying on Third Circuit precedent in *Century Indemnity Co. v. Certain Underwriters at Lloyd's*[195] which held that arbitrability depends on the circumstances of each individual case, including the type of agreement at issue, the purpose of the agreement, the language employed, and the intent of the parties. In *Jesmar*, the court held that types of agreements at issue did not resemble the contracts for reinsurance of reinsurance that compelled arbitration in *Century Indemnity*.[196]

In *H2O Resources, LLC v. Oilfield Tracking Services*,[197] a district court discussed the threshold for establishing or overcoming arbitrability.[198] H2O is a company that provides services to remove water produced during drilling. Carrizo purchased H2O's services and codified the terms in a Master Service Agreement that had an arbitration clause.[199] H2O began to suspect that Carrizo was siphoning proprietary information in order to create an in-house alternative to H2O's

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[185] *Id.* at *2.

[186] *Id.* at *5.

[187] 2017 WL 1078184, at *20 (M.D. Pa. Mar. 22, 2017), *reconsideration denied*, 2017 WL 2535941 (M.D. Pa. June 12, 2017).

[188] No. 2:17-cv-00928, 2018 WL 1471978 (W.D. Pa. Mar. 26, 2018).

[189] *Id.* at *1.

[190] *Id.* at *2.

[191] *Id.*

[192] *Id.*

[193] *Id.*

[194] *Id.* at *5.

[195] 584 F.3d 513 (3d Cir. 2009).

[196] *Jesmar*, 2018 WL 1471978, at *6.

[197] No. 2:18-cv-01164, 2018 WL 3092365 (E.D. Pa. June 22, 2018).

[198] *Id.* at *1.

[199] *Id.* at *3.

services. H2O sued, alleging that Carrizo violated the RICO Act, among other claims, while Carrizo countered with a motion to dismiss to compel Arbitration pursuant to the agreement.[200] The court granted Carrizo's motion to dismiss and compel arbitration. The court noted that H2O had not overcome the presumption of arbitrability merely by pointing to an express provision in the agreement that suggested otherwise.

In *Chesapeake Appalachia L.L.C. v. Scout Petroleum, LLC*,[201] Scout Petroleum purchased oil and gas leases from individuals who had previously entered the leases with Chesapeake Appalachia LLC.[202] The leases had a class arbitration provision, under which Scout filed an arbitration demand on behalf of itself and similarly situated lessors alleging insufficient royalty payments by Chesapeake.[203] The U.S. District Court for the Eastern District of Pennsylvania ruled against Scout, holding that parties may not be compelled to submit to class arbitration without a contractual basis.[204] Scout appealed, and the Third Circuit affirmed. Citing to Supreme Court precedent in *Stolt-Nielsen S.A. v. AnimalFeeds Int'l Corp.*, the Third Circuit held that Scout could not compel Chesapeake to submit to class arbitration regarding the royalty dispute because the leases neither explicitly nor implicitly authorized class arbitration.[205]

In *MarkWest Liberty Midstream & Resources, LLC v. Cecil Township Zoning Hearing Board*,[206] the Cecil Township Zoning Hearing Board granted MarkWest's application for a special exception to construct a natural gas compressor station—subject to conditions that it be of the same general character as other uses permitted in the surrounding "Light Industrial District."[207] MarkWest argued that the conditions imposed exceeded the zoning board's authority under the township's Unified Development Ordinance.[208] Under the ordinance, the board is permitted to place "reasonable" conditions on permits; however, those conditions may be deemed unreasonable if the board's decision lacks substantial evidence that the condition is warranted.[209] The court found that several of the conditions lacked substantial evidence in the record that the project would create an "adverse impact[] not normally generated by this type of use."[210] Accordingly, the Pennsylvania Commonwealth Court granted MarkWest's application for a special exception and struck the conditions that it found lacked substantial evidence.[211]

In *Gorsline v. Board of Supervisors of Fairfield Township*,[212] the Fairfield Township Board of Supervisors approved an energy company's application for a conditional-use permit to locate gas wells on land that was zoned for residential

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[200] *Id.* at *7.

[201] 727 F. App'x 749, 2018 WL 1295736 (3d Cir. Mar. 13, 2018).

[202] *Id.* at *2.

[203] *Id.* at *3.

[204] *Id.*

[205] *Id.* at *5–6.

[206] 184 A.3d 1048 (Pa. Commw. Ct. 2018).

[207] *Id.* at 1055.

[208] *Id.* at 1054.

[209] *Id.* at 1057–58.

[210] *Id.* at 1059 (emphasis omitted) (citation omitted).

[211] *Id.* at 1080–81.

[212] 186 A.3d 375 (Pa. 2018).

and agricultural use.[213] The township's zoning ordinance allowed exceptions for construction in the particular area for uses deemed either "public services" or "essential services."[214] The Pennsylvania Supreme Court held that the proposed gas wells failed to meet either of these definitions, and was not of the same general character as anything currently zoned for, or excepted, in that area. Accordingly, it reversed the decision of the zoning board.[215]

In *Delaware Riverkeeper Network v. Sunoco Pipeline L.P.*,[216] the Pennsylvania Commonwealth Court affirmed the trial court's ruling that conflict and field preemption required dismissal of a complaint by a group of concerned citizens from the Delaware Riverkeeper Network.[217] The concerned citizens sought to challenge Sunoco's proposed construction of a pipeline that they claimed violates the West Goshen Township Zoning Ordinance.[218] The zoning ordinance regulated the location for gas pipelines in the township, arguably prohibiting Sunoco's proposed construction; however, the Public Utility Commission (PUC) approved the construction.[219] The court held that it was the General Assembly's intent that the PUC be *preeminent* in regulating utilities when zoning questions arise.

In *Frederick v. Allegheny Township Zoning Hearing Board*,[220] objectors raised a substantive validity challenge to a zoning ordinance that allowed oil and gas well operations in all zoning districts so long as they satisfied enumerated standards designed to protect the public health, safety, and welfare.[221] The objectors claimed that the zoning ordinance improperly instituted illegal spot zoning in violation of substantive due process, did not comport with the Environmental Rights Amendment in the Pennsylvania Constitution, and violated provisions in the Pennsylvania Municipalities Planning Code (MPC).[222] The Pennsylvania Commonwealth Court held that it was the Commonwealth's duty to regulate how gas drilling is conducted to protect Pennsylvania's waters and air from degradation, while it was the local governments' duty to regulate where oil and gas operations will take place with zoning ordinances.[223] The court held that the objectors did not specify how the standards and conditions in the zoning ordinance violated the Environmental Rights Amendment or deprived them of substantive due process, or the MPC.[224]

In *Briggs v. Southwestern Energy Production Co.*,[225] landowners sued Southwestern for trespass stemming from hydraulic fracturing on a neighbor's property. Southwestern argued it could not be held liable for trespass because it

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[213] *Id.* at 377.
[214] *Id.* at 382.
[215] *Id.* at 388–90.
[216] 179 A.3d 670 (Pa. Commw. Ct. 2018).
[217] *Id.* at 673.
[218] *Id.*
[219] *Id.* at 695.
[220] 196 A.3d 677 (Pa. Commw. Ct. 2018).
[221] *Id.* at 679.
[222] *Id.*
[223] *Id.* at 701.
[224] *Id.* at 701–02.
[225] 184 A.3d 153 (Pa. Super. Ct. 2018).

never entered the landowners' property, while the landowners argued that extracting natural gas below their property, despite a lack of physical intrusion, was nonetheless a trespass. Southwestern additionally argued that the rule of capture precludes liability for trespass during oil drilling.[226] The Pennsylvania Superior Court disagreed with Southwestern's argument, holding that "the rule of capture does not preclude liability for trespass due to hydraulic fracturing."[227] The court further outlined instances when hydraulic fracturing constitutes a trespass: "where subsurface fractures, fracturing fluid and proppant cross boundary lines and extend into the subsurface estate of an adjoining property for which the operator does not have a mineral lease, resulting in the extraction of natural gas from beneath the adjoining landowner's property."[228] On November 20, 2018, the Supreme Court of Pennsylvania agreed to hear the case and review the superior court's decision.

In *Transcontinental Gas Pipe Line Co. v. Permanent Easements*,[229] the Third Circuit affirmed the issuance of a preliminary injunction effectively giving a pipeline company immediate possession of certain rights of way. The Third Circuit rejected arguments from landowners that granting immediate possession violated the constitutional principle of separation of powers because the taking of property by eminent domain is a legislative function and the Natural Gas Act did not grant "quick take" power that permits immediate possession.[230] The Third Circuit held that the Natural Gas Act's grant of standard condemnation powers to natural gas companies does not preclude federal courts from granting equitable relief in the form of a preliminary injunction when gas companies have obtained the substantive right to condemn and otherwise qualify for equitable relief.[231]

In *EQT Production Co. v. Department of Environmental Protection*,[232] EQT initiated declaratory judgment proceeding after it faced civil penalties under Pennsylvania's Clean Streams Law. Under that law, the DEP may levy fines against anyone who allows industrial wastes to flow into the waters of the Commonwealth. EQT faced such fines because of "leaks from an impoundment used to contain impaired water flowing back from hydraulic fracture gas wells."[233] DEP justified its fines under the "soil-to-water" and "water-to-water" theories, which state that "every day that contaminants from the [facility] remain in the subsurface soil and passively enter groundwater and/or surface water," the violating party may be assessed fines for "continuing violations," and that fines may also be assessed when contaminants move from one body of water to another.[234] EQT argued that DEP's theories were so broad that they ran counter to the plain wording of the statute and to the legislative intent of an earlier environmental regulation, and were not supported by precedent.[235] The

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[226] *Id*. at 155.

[227] *Id.* at 163.

[228] *Id.* at 163–64.

[229] 907 F.3d 725 (3d Cir. 2018), *petition for cert. docketed*, No. 18-1206 (Mar. 18, 2019).

[230] *Id.* at 734–35.

[231] *Id.* at 741.

[232] 181 A.3d 1129 (Pa. 2018).

[233] *Id.* at 1130.

[234] *Id.*

[235] *Id.* at 1131.

Pennsylvania Supreme Court agreed, holding that the Clean Streams Law was ambiguous, at least with respect to the "water-to-water" theory. EQT did not violate the regulation when pollutants moved from one body of water to another because neither the statute's plain language, nor the intent of the legislature, comprehended such movement.[236]

In *Marcellus Shale Coalition v. Department of Environmental Protection*,[237] the Marcellus Shale Coalition, a membership organization, challenged several regulations relating to unconventional gas well operations as governed by Pennsylvania's Oil and Gas Act of 2012.[238] They argued that each new regulation was void, vague, and lacked statutory authority.[239] The Pennsylvania Supreme Court disagreed, holding that the Marcellus Shale Coalition failed to meet its burden in showing it was entitled to clear relief on each claim.[240]

In *B&R Resources, LLC v. Department of Environmental Protection*,[241] the Pennsylvania Commonwealth Court reviewed an Environmental Hearing Board (EHB) adjudicatory decision regarding whether an officer of an oil and gas exploration company may be held personally liable under the participation theory for failing to plug dozens of abandoned wells pursuant to Pennsylvania state law.[242] Under Pennsylvania's 2012 Oil and Gas Act, DEP may require the plugging of non-producing wells.[243] The DEP directed the B&R exploration company, and one of its managing members, to plug 47 non-producing wells following safety violation notices; it failed to do so, arguing that they lacked the requisite financial resources.[244] At a hearing, the EHB found the managing member personally liable for failing to plug the wells. B&R appealed, arguing that the managing member could not be held personally liable "because his involvement consisted of inaction and that the EHB imposed liability on [him] based on his status as sole owner and manager of B&R, rather than his conduct."[245] The Pennsylvania Commonwealth Court agreed with B&R and reversed the EHB ruling, holding that because the company did not have the financial means to plug the wells, there could be no causal nexus between wrongful conduct and a violation.[246]

In *Walney v. SWEPI LP*,[247] a class action, several Pennsylvania landowners alleged that SWEPI, with whom they executed oil and gas leases, failed to pay bonuses due under their lease terms.[248] While the lease bonuses were not usually specified in the leases themselves, they appeared in bank drafts between the parties. Accordingly, the landowners argued that the bank draft, coupled with the

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[236] *Id.* at 1149.

[237] 185 A.3d 985 (Pa. 2018).

[238] *Id.* at 985–86.

[239] *Id.* at 986.

[240] *Id.* at 1004.

[241] 180 A.3d 812 (Pa. Commw. Ct. 2018).

[242] *Id.* at 814.

[243] *Id.*

[244] *Id.* at 815.

[245] *Id*. at 817.

[246] *Id.* at 821–22.

[247] 311 F. Supp. 3d 696 (W.D. Pa. 2018).

[248] *Id.* at 700.

leases, created mutual intent and an enforceable contract regarding lease bonuses.[249] SWEPI countered that there was no enforceable contract. The district court disagreed, finding that the correspondence between the landowners and SWEPI constituted an intent to be bound, with definite terms, and for valid consideration.[250]

C. Administrative Developments

In June 2018, DEP finalized a permitting program to reduce methane emissions from natural gas well sites, compressor stations, and along pipelines. The general permits establish Best Available Technology requirements and other applicable federal and state requirements including air emission limits, source testing, leak detection and repair, recordkeeping, and reporting requirements for the applicable air contamination sources. The GP-5A permit was developed under the authority of Section 6.1 of the Air Pollution Control Act (35 P.S. § 4006.1(f)) and 25 Pa. Code ch. 127, subch. H (relating to general plan approvals and operating permits), and is applicable to unconventional natural gas well site operations and remote pigging stations. The revised GP-5 permit was developed under the authority of section 6.1(f) of the Air Pollution Control Act and 25 Pa. Code ch. 127, subch. H, and is applicable to natural gas compressor stations and processing plants and transmission stations.

Governor Tom Wolf again unsuccessfully introduced legislation to create a severance tax on oil and natural gas production. Senate Bill 1000 and House Bill 2253 called for between 4 cents and 7 cents per thousand cubic feet of natural gas, depending on the price, that would have begun on July 1. The proposed tax would have generated an estimated $248.7 million in the fiscal year following its proposal. Pennsylvania currently imposes no severance tax but does impose impact fees, which paid $ 209.6 million this year to counties and municipalities affected by shale wells

XI. TEXAS

A. Judicial Developments

Texas courts addressed numerous energy-related cases in 2018. Lease maintenance and deed construction remained hot areas, while the courts also examined a number of disputes between lessees. The following cases provide a highlight of recent decisions found to be worthy of noting.

In *Endeavor Energy Resources, L.P. v. Discovery Operating, Inc.*,[251] the Texas Supreme Court affirmed the Eastland Court of Appeals ruling that a portion of Endeavor's mineral leases automatically terminated based on language of the leases' continuous-development and retained-acreage clauses. Specifically, the court analyzed whether Endeavor was bound by the proration unit identified in the initial plat Endeavor filed with the Railroad Commission. The retained-acreage clause, triggered by the cessation of continuous development, terminated the lease except with respect to the land "within a governmental proration unit assigned to a well" that complied with the Railroad Commission rules and regulation for

[249] *Id.* at 707.

[250] *Id.* at 725.

[251] 554 S.W.3d 586 (Tex. 2018).

"obtaining the maximum producing allowable for the particular well."[252] Although Endeavor had filed plats with the Railroad Commission assigning proration units of around 80 acres for four different wells, it later asserted that each well should be assigned 160 acres, as was sometimes allowed under the appropriate field rules. Accordingly, Endeavor claimed the full 160 acres under the leases.

The court found the language "assigned to" in the retained-acreage clause unambiguously referred to "the operator's assignment of a proration unit through its filing of a proration plat with the Commission," rather than the Commission's assignment of units based on special field rules.[253] Therefore, because the operator is typically required to designate a well's acreage and proration unit on a certified plat per statewide and/or special field rules, these designations had implications on the contract rights between the parties, including the acreage retained. Additionally, the court found that the retained-acreage clause language calling for the "maximum producing allowable" was intended to restrict the acreage filed in the plat such that it only contained the amount necessary to reach the maximum producing allowable for that particular well. Therefore, the 80-acre-per-well plat filed originally was the correct amount since Endeavor did not need the full 160 acres to achieve the maximum allowable.

In *Greeheyco, Inc. v. Brown*,[254] the Eastland Court of Appeals analyzed a lease's continuous drilling clause to determine whether the lease, as amended, had terminated. According to the continuous drilling clause, the lease would continue so long as the lessee engaged in continuous drilling operations, which it defined as "drilling which must be completed to a minimum depth of 1,000 feet following within no more than one hundred twenty (120) days after cessation of drilling operations from the previous well to its total depth on the Leased Premises."[255] The amendment to the lease, which relinquished formations above the Caddo formation, stated that "notwithstanding the release of the formations . . . a well drilled to a minimum depth of 1,000 feet shall still constitute 'continuous drilling operations' as defined in [the lease]."[256] The amendment also provided that its terms superseded any conflicting terms in the original lease.

On July 18, 2015, the lessee completed a well at a depth of 1,050 feet. On November 12, 2015, the lessee commenced actions to drill a second well. While the parties agreed that November 15, 2015 marked the expiration of the 120-day continuous-drilling period, they disagreed as to what constituted "continuous drilling operations," and, as a result, as to whether the lease had terminated. The lessor contended that the lessee's act of drilling the first well was ineffective to trigger the continuous drilling clause, because 1,050 feet was not a sufficient depth to reach the Caddo formation, and because the amendment released all formations above the Caddo formation. The court disagreed, stating that when parties to a contract use the term "notwithstanding," they "agree that the 'notwithstanding' provision must be given effect regardless of any contrary provisions of the contract."[257] Accordingly, because the lease amendment specified that drilling to a

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[252] *Id.* at 600.

[253] *Id.* at 601.

[254] 565 S.W.3d 309 (Tex. App.—Eastland 2018, no pet.).

[255] *Id.* at 322.

[256] *Id.*

[257] *Id.* at 324.

minimum depth of 1,000 feet constituted continuous drilling operations "notwithstanding" the fact that it released formations lying at that depth, the court held that the continuous drilling clause saved the lease from termination.

In *TEC Olmos, LLC v. ConocoPhillips Co.*,[258] the court construed a *force majeure* clause which contained the following "catch-all" provision: "*any* other *cause* not enumerated herein but which is *beyond the reasonable control of the Party whose performance is affected*, then the performance of any such obligation is suspended . . . ."[259] The court held that this "catch-all" language did not include events which were reasonably foreseeable, such as the drop in the price of oil which was at issue in this case. *TEC Olmos* stands for the proposition that courts will read doctrines such as foreseeability into "catch-all" provisions of *force majeure* clauses when a party attempts to rely on these provisions in a contract dispute.

In *Murphy Exploration & Production Co.—USA v. Adams*,[260] the Texas Supreme Court declined to apply a standard which would have required an operator to prove its horizontal offset well in the Eagle Ford Shale protected against drainage. Lessors and Murphy's predecessor-in-interest entered into leases containing an offset well provision that required completion of a well if a draining well was located within a certain distance from the lease line. The provision was silent as to the required location of the offset well.

An adjacent well was drilled within the triggering number of feet. Murphy timely drilled the offset well, which it located 1,800 feet from the lease boundary line. Lessors sued Murphy for breach of contract, asserting the well Murphy drilled was too far from the adjacent well to be considered an offset well to protect against drainage. The Texas Supreme Court declined to find a breach, reasoning that "imposing a location or proximity requirement that goes beyond the leases' express language—is an unreasonable interpretation of the language the parties chose."[261]

In *TRO-X, L.P. v. Anadarko Petroleum Corp.*,[262] the Texas Supreme Court was called to decide whether a renegotiated series of leases constituted "top leases." TRO-X, L.P. owned a 5% back-in after-payout working interest in a series of 2007 leases owned by Anadarko. The agreement creating the back-in provided that the back-in would "extend to and be binding upon any renewal(s), extension(s), or top lease(s) taken within one (1) year of termination of the underlying interest."[263] In 2011, the lessors under the 2007 leases notified Anadarko that it had breached an offset well provision in the leases, thereby partially terminating the leases. Anadarko agreed, and purchased new leases in 2011 covering the same interest as the 2007 leases. It recorded the 2011 leases, and filed a release of the 2007 leases a few months later. The issue of whether TRO-X's back-in applied to the 2011 leases therefore depended on whether the 2011 leases were "top leases" of the 2007 leases.

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[258] 555 S.W.3d 176 (Tex. App.—Houston [1st Dist.] 2018, pet. filed).

[259] *Id.* at 179.

[260] 560 S.W.3d 105 (Tex. 2018).

[261] *Id.* at 111.

[262] 548 S.W.3d 458 (Tex. 2018).

[263] *Id.* at 460.

Interestingly, TRO-X did not argue the 2011 leases were "renewals" or "extensions" of the 2007 leases. Rather, it argued that the 2011 leases were simply top leases. The court held that they were not, because the 2011 leases were not contingent on termination of the 2007 leases (a defining feature of a top lease). Rather, the 2011 leases terminated the 2007 leases entirely. The court explained the party contending that a new lease did not terminate a previous lease held the burden of proof "that the parties intended for the previous lease to survive execution of the new lease."[264]

Because there was no specific language in the unambiguous 2011 leases showing an intent that the 2007 leases would survive execution of the 2011 leases, the court concluded that the 2011 leases terminated the 2007 leases. Thus, the 2011 leases were not top leases, because they were not contingent on termination of the 2007 leases—they themselves constituted both a termination of the 2007 leases and new leases since they covered the same mineral interest. As new leases, they were unburdened by TRO-X's back-in.

In *Devon Energy Production Co., L.P. v. Apache Co.*,[265] the Eastland Court of Appeals held that Section 91.402 of the Texas Natural Resources Code does not require a working interest owner to pay lease royalties to mineral interest owners who have leased to a different working interest owner. Apache and Devon held leases from separate mineral owners under the same lands, but could not agree on a JOA. Thereafter, Apache went on to drill seven producing oil and gas wells on the property, and, after payout, paid Devon its share of the net revenue from production as its cotenant. Neither Apache nor Devon paid the lessors under the Devon leases any royalty. Devon filed a claim against Apache, arguing that the statute requires Apache to directly pay the Devon lessors' royalties under Devon's leases. In part, the statute provides, the proceeds derived from the sale of oil or gas production from an oil or gas well located in this state must be paid to each payee by payor on or before 120 days after the end of the month of first sale of production from the well.

Finding in favor of Apache, the court held that Apache and Devon's lessors did not have a payor-payee relationship under the statute, since Apache did not undertake to pay the Devon lessors by entering into leases with them. Therefore, even though Apache was the operator of the producing well, it was not a payor under the statute. Thus, the obligation for payment of lease royalties to Devon's lessors lay squarely on Devon, not Apache.

In *Eagle Oil & Gas Co., v. Shale Exploration, LLC*,[266] the court affirmed a $14.3 million jury verdict for lost profits resulting from the theft of an operator's leasing information. Along with its two partners, Shale Exploration, LLC wanted to develop an oil and gas prospect in Daniels County, Montana. During negotiations to develop the prospect, Shale shared the following with Eagle Oil & Gas Company: (1) a map identifying areas of interest and the anticipated value placed on each area; (2) lease schedules; and (3) maps distinguishing between land where Shale negotiated mineral leases from land not yet leased. Although Eagle formerly had a confidentiality agreement with Shale's parent company, that company had divested Shale, and Eagle and Shale never reached an agreement.

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[264] *Id.* at 464.

[265] 550 S.W.3d 259 (Tex. App.—Eastland 2018, pet. denied).

[266] 549 S.W.3d 256 (Tex. App.—Houston [1st Dist.] 2018, pet. dism'd).

After learning Shale agreed to develop the prospect with Apache, Eagle used Shale's information to conduct its own leasing activities in the prospect, causing Shale to spend more money to fulfill contractual obligations it owed to a third party.

Despite the lack of a formal agreement, the court found that a jury could have reasonably found that Eagle agreed to hold Shale's information in confidence and use it only for negotiating the deal with Shale because Shale relied on multiple assurances from Eagle representatives that it would not share the information prior to the initial meeting between the parties. The opinion recognized that Shale spent extensive resources developing the information because the mineral ownership interests were highly fractionalized and the title research was done manually at the county courthouse. As such, there were over a hundred Shale employees working at the county courthouse for over a year to determine the prospect mineral owners' identities. Further, Shale used specialized software to generate the information it shared with Eagle. By using the information, Eagle unjustly capitalized on Shale's labor-intensive efforts to uncover the prospect mineral owners' identities. For these reasons, the court held that the information constituted a trade secret.

In *Pacific Energy & Mining Co. v. Fidelity Exploration & Production Co.*,[267] the court determined that the relationship created between two oil and gas companies under the assignment of an asset purchase agreement (APA) for the sale of oil and gas assets was only an assignment, not a joint venture or a partnership. As part of the APA assignment, the purchaser and the assignee executed a memorandum of understanding (MOU), which stated the following relevant points:

(1) the assignee would fund 100% of the acquisition price under the terms of the APA;
(2) all assets from the APA would be assigned from purchaser to assignee;
(3) assignee would own 100% of the assets acquired under the APA;
(4) both parties would enter into an operating agreement in which purchaser would be the operator; and
(5) purchaser would receive 30% net profit.

The court concluded that this arrangement created an assignment to the assignee, and the fact that the purchaser still retained its obligations under the APA did not change the relationship. Furthermore, the court decided that the assignment did not create a partnership between the purchaser and assignee for the following reasons under a totality of the circumstances test: (1) profit sharing paid as wages or compensation does not indicate a partnership interest; (2) the MOU did not have language indicating intent to be partners; (3) there was no evidence that both parties had mutual control of the business; and (4) the MOU did not address loss sharing. As such, the assignee could not breach a fiduciary duty to the purchaser because there was no partnership or joint venture relationship giving rise to such a duty.

In *Perryman v. Spartan Texas Six Capital Partners, Ltd.*,[268] the Texas Supreme Court emphasized that a reservation of minerals in a deed's "less, save

[267] No. 01-17-00594-CV, 2018 WL 3543103 (Tex. App.—Houston [1st Dist.] July 24, 2018, no pet.).

[268] 546 S.W.3d 110 (Tex. 2018).

except" clause must be drafted with clear language; otherwise it will be construed as an exception. The clause at issue saved and excepted "an undivided one-half (1/2) of all royalties from the production of oil, gas and/or other minerals that may be produced from the above described premises which are now owned by Grantor."[269] Because the clause did not use the word "reserve," it was not a reservation, but an exception. The court further determined that the phrase, "which are now owned by the Grantor," modified the word "premises," and not "royalties" or "minerals" because there is no comma after "premises." Accordingly, the court concluded that the deed conveyed 1/2 and excepted 1/2 of *all* of the parcel's royalty interests, not just 1/2 of the royalty interests the grantor *then owned*.

In *U.S. Shale Energy II, LLC v. Laborde Properties, L.P.*,[270] the Texas Supreme Court interpreted a royalty reservation in a 1951 deed to determine whether it was fixed (a fixed percentage of total production), or floating (a fraction of the royalty amount in the applicable oil and gas lease). The double-fraction deed reserved an undivided 1/2 interest in the oil and gas royalty, "the same being equal to one-sixteenth (1/16) of the production."[271] The court held that the deed reserved a floating 1/2 interest. First, no lease was in effect at the time of the deed's execution. As a result, the deed's language reserving 1/2 of a "royalty" must have referred to some royalty "that could come into being at some point in the future."[272] Second, the grammatical structure supported the interpretation of a floating 1/2 interest, because the second fraction was offset by a comma, which indicated a nonrestrictive dependent clause. According to the court, such clauses provide mere additional information incidental to the central meaning of a sentence. Thus, the nonrestrictive dependent clause in this case did not modify the first fraction, which clearly intended to reserve a floating 1/2 interest.

In the case of *In re Primera Energy, LLC*,[273] a group of investors sued an investment firm for Deceptive Trade Practice Act (DTPA) violations and other claims based upon investments in oil wells that did not yield any return. The owner of the investment firm that marketed these wells took millions of dollars in investor funds as *owner draws*, making the venture unprofitable and leaving the company unable to pay vendors.

The investors claimed the DTPA applied based upon services provided by the firm under a management and operating fee provision in the investment contracts. In order to qualify for protection under the DTPA, the plaintiff must be a consumer and the complaint must be related to goods or services. The lower court held that the plaintiff here was a non-operating interest owner, and based upon previous case law, held that a non-operating interest holder was not a consumer under the DTPA. The court reasoned that simply being the front-man incurring debts related to a well for which it was to be reimbursed was not a service. The plaintiff tried to distinguish previous precedent by pointing to the fact that it paid an upfront fee before any costs were incurred on the part of the investment firm, and thus it was not reimbursing the firm. Further, the plaintiff pointed to the fee for supervision

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[269] *Id.* at 114.

[270] 551 S.W.3d 148 (Tex. 2018).

[271] *Id.* at 150.

[272] *Id.* at 153.

[273] 579 B.R. 75 (Bankr. W.D. Tex. 2017). Note: The Committee's annual update for 2017 did not discuss this opinion due to the opinion's issuance on December 29, 2017.

during the well operations that the firm charged. The court held that pre-billing for projected costs did not affect the analysis of whether the operator was providing a service and that an operator charging a management fee to non-operating interest holders did not make their actions a service relative to the non-operating interest owners. Thus, the court found that the plaintiff did not qualify for protection under the DTPA.

XII. WEST VIRGINIA

A. Legislative Developments

The 2018 West Virginia Legislature passed the highly publicized and noteworthy House Bill 4268, involving mineral development by a majority of cotenants. This Act affected various sections of the West Virginia Code, including §§ 22C-9-3, 22C-9-4, and 37-7-2, as well as creating Chapter 37B entitled "Mineral Development."

Section 22C-9-3 speaks to the application of the article and exclusions therefrom, while Section 22C-9-4 sets forth the creation, terms, duties, and authority of the Oil and Gas Conservation Commission. Furthermore, Section 2, entitled "Waste by cotenant," was added to Chapter 37, Article 7 of the West Virginia Code.

The majority of House Bill 4268 sets forth Chapter 37B pertaining to Mineral Development. The purpose of this chapter is to encourage and promote exploration for and development, production and conservation of oil, natural gas and their constituents. This chapter is applicable in situations in which there are seven or more royalty owners. If an operator or owner makes or has made reasonable efforts to negotiate with all royalty owners in an oil or natural gas mineral property and royalty owners vested with at least three fourths of the right to develop, operate, and produce oil, natural gas, or their constituents consent to the lawful use or development of the oil or natural gas mineral property, the operator's or owner's use or development of the oil or natural gas mineral property is permissible, is not waste, and is not trespass. A nonconsenting cotenant is entitled to receive, based on his or her election, either: (i) a prorata share of production royalty; or (ii) may elect to participate in the development and receive his or her prorata share of the revenue and cost equal to his or her share of production attributable to the tract or tracts being developed. The Chapter further sets out how payments will be made to the non-consenting owners, as well as those with unknown or unlocatable interests.

Within the first 120 days after any amount is reserved for those unknown or unlocatable interest owners, the consenting cotenants, along with their lessees, operators, agents, etc., are required to make a report to the State Treasurer as the Unclaimed Property administrator. The reports are then to be made every quarter, along with the remittance of the funds for the owners. Section 37B-1-4(g) allows for a bona fide surface owner to file an action to quiet title to the interests of all unknown and unlocatable owners after seven years has elapsed since the date of the first report to the State Treasurer.

B. *Judicial Developments*

In *L&D Investments, Inc. v. Mike Ross, Inc.*,[274] the Supreme Court of Appeals of West Virginia reversed the order of the Circuit Court of Harrison County granting summary judgment to Mike Ross, Inc. (MRI) on the grounds that the plaintiffs' (L&D) claims were barred by the three-year statute of limitation set forth in W. Va. Code § 11A-4-4. In this case, the oil and gas interests had been severed from the surface and coal interests in 1903. A real property tax assessment for 100% of the oil and gas interest remained on the landbooks until 1999 (master assessment). Additional assessments were entered on the landbooks as early as 1988 when a personal property assessment was transferred over to the real property landbooks. Those assessments were based on a gas producer's report of income from production. The personal property assessments that were transferred to the real property landbooks were further separated in 1990 with descriptions of "leased O&G," and containing well references therein. The result of the transfer of the personal property assessments led to real property tax tickets being issued, and taxes being paid on both those tickets and the master assessment.

In 1999, the owners of a 1/20th interest requested separation of their respective interests in the subject property from the master assessment. However, the master assessment remained on the landbooks for the year 2000, being noted as 80% interest in oil and gas, and the real property taxes were not paid and became delinquent. In 2003, a tax sale deed was issued to MRI conveying an eighty percent undivided interest in the oil and gas based on the delinquent master assessment. L&D purchased certain oil and gas interests in 2013 and notified the entities then extracting oil and gas from the property of its purchase and its right to receive any royalty payments. Those producers then proceeded to inform L&D that the interest it was claiming had been previously sold in 2001 to MRI for delinquent taxes.

The parties in this case disputed the validity of the tax deed issued to MRI in 2003. L&D contended that the taxes with respect to their oil and gas interests were never delinquent because it and its predecessors in interest paid and continued to pay the real property tax tickets they received from the Assessor thereby making the tax deed issued to MRI void. On the other hand, MRI argued that the payments made by the L&D, and its predecessors in interest, were for erroneous assessments of royalty based personal property and were therefore improperly placed on the landbooks.

The supreme court of appeals reversed, holding that the mineral interests were never delinquent, and therefore, the sale of the subject mineral interests for delinquent taxes was void as a matter of law; and that L&D's claims were not barred by the three-year statute of limitation set forth in W. Va. Code § 11A-4-4 for tax sale deeds resulting from duplicate assessment that were void ab initio. Further, in the case of two assessments of the same land under the same claim of title for any year, one payment of taxes under either assessment is all the state can require. The case was remanded for further proceedings consistent with the opinion of the court.

In *Berghoff v. Chesapeake Appalachia, LLC*,[275] the court reversed the order below granting summary judgment to Chesapeake Appalachia, LLC (Chesapeake),

[274] 818 S.E.2d 872 (W. Va. 2018).

[275] 747 F. App'x 120 (4th Cir. 2018).

and its successor in interest, SWN Production Company, LLC (SWN), holding that: (1) there was not sufficient fact finding to satisfy the burden of summary judgment concerning the habendum clause of the mineral lease; and (2) Chesapeake did not extend the lease beyond its primary term pursuant to the its pooling provision. The lease, in addition to the habendum clause, contained a pooling provision requiring the mailing of notice to the lessors and an addendum provision requiring the lessors' reasonable approval in well pad location. Initial preparations of locating a well pad on the leased premises were abandoned due to a dispute on the location of the access road, and Chesapeake subsequently drilled a well pad on land adjoining the leased premises. The leased premises were included in a unit before the primary term expired, but Chesapeake did not mail the notice of the unitization to the lessors until after the primary term expired.

The parties disputed whether the lease was extended beyond its primary term pursuant to the habendum clause, and whether the leased premises were properly pooled in a unit. The district court granted summary judgment to Chesapeake and SWN, holding that: (1) although Chesapeake abandoned locating the well pad on the leased premises, the lessors disputing the location of the access road location was unreasonable and constituted equitable estoppel for the benefit of Chesapeake; and (2) Chesapeake's operation of the pooled unit without the mailing of notice satisfied the doctrine of substantial performance and properly unitized the leased premises.

The Fourth Circuit reversed both of the district court's findings. First, it held that determining whether the lessors unreasonably rejected the proposed access road location was a question of fact for the jury, especially considering the inclusion of the addendum provision requiring such approval by the lessors. Second, it held that the mailing of notice to the lessors was a stated prerequisite to pooling, not a minor occurrence that was impossible or impractical; thus, Chesapeake failing to do so resulted in the leased premises not being properly unitized. The case was vacated and remanded for further proceedings consistent with those of the Fourth Circuit.

In *Kupfer v. Chesapeake Appalachia, LLC*,[276] the West Virginia Supreme Court affirmed the order of the lower court holding that the circuit court did not err in determining that the deed in question did not reserve the oil and gas within and underlying the subject property. By deed dated May 2, 1990, the Petitioners (Kupfer) conveyed unto C. Michael Blair, predecessor in title to Respondent, Zachary Blair, nine tracts of land, including the 60-acre subject property. The subject deed first describes the conveyance as being the following described real estate, whose Tax Map Number is 21, Parcels 4, 13, 14, 15, 16, 17, 18, 19, and 20, to-wit, followed by the first eight unrelated tracts of land and their respective legal descriptions. Immediately following these descriptions, the subject deed stated that there was excepted and reserved from said parcels all the coal, oil, gas and other minerals, on, within and underlying the property hereby conveyed. After this reservation language, the subject deed described the ninth tract of land, being the subject property, and its legal description; however, no reservation of the oil or gas followed the subject property and its legal description.

The parties disputed whether the subject deed reserved the oil and gas within and underlying the subject property in addition to the first eight unrelated tracts of

[276] No. 17-0527, 2018 WL 2175553 (W. Va. May 11, 2018) (unpublished).

land. The circuit court concluded that the deed unambiguously reserved the oil and gas within and underlying the first eight tracts of land but did not reserve any oil or gas within and underlying the subject property. On appeal, Kupfer argued that the initial language referring to the following described real estate, whose Tax Map Number is 21, Parcels 4, 13, 14, 15, 16, 17, 18, 19, and 20, to-wit, completed the conveyance of the nine tracts of land, and that the subsequent parcel by parcel descriptions in the subject deed were unnecessary, resulting in the remaining reservation language being applicable to the initial language conveying all nine tracts of land. Further, the phrase "said parcels" in the reservation language should be liberally construed to refer to the initial language of the nine tracts of land and not just the eight tracts of land immediately preceding the reservation language. The Supreme Court of Appeals of West Virginia disagreed with Kupfer and affirmed the order of the circuit court, criticizing Kupfer's limited scope of analysis in determining the intent of the parties and their interpretation of words beyond their plain and ordinary meaning.

In *Richards v. EQT Production Co.*,[277] a federal jury found that EQT Production Company (EQT Production) breached the terms of three oil and gas leases by failing to pay the Richards the full amount of royalties due. The three leases in question contained royalty wording obligating the lessee to pay one-eighth (1/8) of the market price of the gas from each and every gas well drilled on said premises, the product from which is marketed and sold off the premises, said gas to be measured by a meter. EQT Production, successor in interest to the original lessee, sold the natural gas produced from the leased premises to an affiliate, EQT Energy, LLC (EQT Energy), pursuant to a Gas Sales Contract. The Gas Sales Contract established a pricing formula which defined the wellhead as the relevant valuation point of the royalty payments, applying a work-back method to deduct certain post-production costs from the Richards. The Richards brought suit, alleging that EQT Production breached the royalty provision of the three leases by not remitting payments based on the price of the downstream market, which would not factor in the deduction of post-production costs to royalty payments. EQT Production argued that although the three leases did not contain *at the wellhead* language, there are markets at multiple potential points of sale, and the Richards had failed to show that the price paid by EQT Energy at the wellhead was not, in fact, the market price of the gas at that point of sale. The case was tried before a jury, who agreed with the Richards and found that EQT Production had failed to pay the Richards the full amount of the royalties due.

C. *Administrative Developments*

Effective April 1, 2018, the West Virginia Department of Environmental Protection modified and amended legislative rule 60CSR3 titled The Voluntary Remediation and Redevelopment Rule relating to the eligibility, procedures, standards, and legal documents required for voluntary remediation activities and brownfield revitalization. This Rule is applicable to properties involved in, but not limited to, the extraction of oil and gas and pipeline transportation.

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[277] No. 1:17-cv-00050, 2018 WL 3321441 (N.D. W. Va. July 6, 2018) (Memorandum Opinion and Order Denying Plaintiffs' Motion for Partial Summary Judgment).

XIII. WYOMING

A. *Legislative Developments*

During its 2018 Budget Session, the Wyoming State Legislature addressed four issues important to the oil and gas industry. Through S.F. 27, the legislature enacted new procedures for Wyoming sales and use tax audits. Along with other provisions, the statute sets time limits for commencement of audits by the Wyoming Department of Audit.[278]

Second, through S.F. 18, the legislature established an Orphan Site Remediation Account to fund reclamation activities when an operator does not reclaim lands.[279]

Third, addressing ad valorem and gross products tax practices, the legislature passed H.B. 72, a bill allowing Wyoming counties to deduct court costs, attorney's fees, and other extraordinary costs before distributing tax revenues. In addition, the bill protects a county treasurer from claims by other governmental entities if the treasurer is unable to collect taxes because the taxpayer declares bankruptcy or is otherwise unable to pay taxes.[280]

Finally, passing S.F. 16, the legislature required the Wyoming Department of Environmental Quality to initiate a rulemaking process to address the plugging, abandonment, post-closure monitoring and corrective actions for underground injection wells and related facilities.[281]

B. *Judicial Developments*

Berenergy Corp. v. BTU Western Resources, Inc., was a dispute between a mining company operating under federal coal leases and a party holding a federal oil and gas leases in the same area of northeastern Wyoming. Considering summary judgment rulings by a district court, the Wyoming Supreme Court held that under federal law BLM was the only entity that could decide about how the minerals under federal leases should be developed. The supreme court remanded the case to the district court to determine whether BLM would participate. If not, the supreme court concluded that the district court would likely be required to dismiss the lawsuit.[282]

Addressing a complex probate case involving overriding royalty interests (ORRI), *Lon V. Smith Foundation v. Devon Energy Corp.*, the Wyoming Supreme Court affirmed a lower district court's summary judgment ruling in favor of an oil and gas company.[283] The court determined that the plaintiff, a foundation that was recipient of the ORRI under a will, was not entitled to disputed funds held by the oil and gas company. The court ruled the defendant oil and gas company did not violate the Wyoming Royalty Payment Act (WRPA) by holding the funds in an

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[278] Wyo. Stat. Ann. §§ 39-15-108(a), 39-16-108(a); S. Enrolled Act 23, 2018 Leg., 64th Budget Sess. (Wyo. 2018).

[279] Wyo. Stat. Ann. §§ 16-1-206, 35-11-1701; S. Enrolled Act 1, 2018 Leg., 64th Budget Sess. (Wyo. 2018).

[280] Wyo. Stat. Ann. § 39-13-111(a)(i), (c); H. Enrolled Act 3, 2018 Leg., 64th Budget Sess. (Wyo. 2018).

[281] Wyo. Stat. Ann. § 35-11-302(a)(viii); S. Enrolled Act 2, 2018 Leg., 64th Budget Sess. (Wyo. 2018).

[282] 2018 WY 2, ¶¶ 36–39, 43, 408 P.3d 396, 403–05.

[283] 2017 WY 121, 403 P.3d 997.

internal account instead of depositing the funds in an escrow account, as required by the WRPA. The court ruled the plaintiff had no authority to make a claim under the escrow provision of the WRPA and therefore the escrow requirement was inapplicable.[284]

C. Administrative Developments

In early 2018, the Wyoming Oil and Gas Conservation Commission (WOGCC) revised its rules to: (1) increase filing fees to $250 per application; (2) establish a $150 fee for hearing continuances; and (3) enact new public records disclosure and copying requirements.[285]

[284] *Id.* ¶¶ 52, 55, 403 P.3d at 1012–13.

[285] 055-0001-5 Wyo. Code R. § 2 (available at http://pipeline.wyo.gov/wogcchelp/commission.html); *see* Ch. 5, § 2, and Ch. 6.

Water: Practical Challenges and Legal Rights to Acquire and Recycle Water for Hydraulic Fracturing

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Synopsis

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Abstract and Disclaimers

Most oil and gas production in the United States is the result of hydraulic fracturing. The dominance of hydraulic fracturing (commonly referred to as "fracing" or "fracking"[1]) has made the use, reuse, and disposal of relatively large amounts of water indispensable to modern oil and gas production. It has also raised numerous and potentially thorny legal issues that are generally resolvable within the field of water law, not oil and gas law. Section I of this article surveys the principal technical and economic dimensions of water usage in oil and gas production, including the reuse of produced water. Section II surveys the legal dimensions of water usage for fracking operations. Section II.A provides a general summary of state water law across the country, with particular attention to the principal oil and gas producing states west of the Missouri River. However, because of the exceptional water-related aspects of oil and gas production generally and those of fracking in particular, these states have carved out legal and regulatory exceptions and established distinct permitting regimes for the use of water in oil and gas operations. Section II.B provides a summary of these permitting regimes. Section II.C similarly provides an overview of how some oil and gas producing states in the West are confronting the increasingly important issue of water reuse: specifically, the treatment and reuse of produced water for further oil and gas operations and for other beneficial uses.

[1] Like most other aspects of oil and gas production in the United States, the spelling of the vernacular form for fracturing has become a divisive issue. Advocates for the oil and gas industry, evincing a prudishness rarely found in the oil patch, perceive an intended slight in the use of "frack," on the grounds that it is spelled similarly to a vigorous but offensive Anglo-Saxon verb, and so prefer the spelling of "frac," which seems delicate, even French. Opponents of hydraulic fracturing do generally spell it as "frack." Media sources generally prefer the latter spelling, as does the Foundation; courts are divided on the issue. Because the latter spelling enables a consistent spelling and pronunciation of the word in its verb and gerund forms, this article uses "frack" and "fracking," a usage that avoids the risk of mispronouncing "fracing" so as to rhyme with "racing."

Before proceeding further, two disclaimers are necessary. First, the disposal of produced and other water related to fracking generally falls within the domain of environmental law, and is the subject of other papers delivered at this conference.[2] That subject is not covered in this article. Second, the jurisdictional and doctrinal variety of state water law regimes across the United States, and the peculiarities of federal water and public lands law, make a comprehensive treatment of this topic impossible within the confines of this article. Two recently published books treat the subject in greater detail.[3] Readers who have access to the Foundation's electronic library should consult papers written for prior Foundation institutes that addressed the usage of water in oil, gas, and mineral development: its 2012 Special Institute, *The Water-Energy Nexus: Acquisition, Use, and Disposal of Water for Energy and Mineral Development*, and its 2016 Special Institute, *Water Acquisition and Management for Oil & Gas Development: Legal and Regulatory Requirements*. The author's debt to these and other Foundation papers is considerable and has been noted.

The goal of this article is to assist the practitioner in thinking like a water lawyer: to recognize the principal issues and challenges involved in securing water supplies for fracking operations and in reusing produced water, across the most important state law jurisdictions.

I. WATER AND HYDRAULIC FRACTURING: LAW AND BUSINESS, RACING TO ADAPT

The importance of water for successful hydraulic fracturing and its significant impact on operational profitability have created many opportunities in the oil patch. Substantial capital has been infused into the nascent water business; innovation continues at a fast pace, rent-seeking has become more creative, and regulatory concerns and the regulatory framework are constantly evolving. The legal community recognizes that across state law jurisdictions, some of the received doctrines in water law will engender conflict as the value of water increases. Most expect that innovations in water management for fracking will create wealth for some participants, but there is a corresponding fear that poor water management will impoverish others. There is plenty of motivation to get it right—how to best use water, and how to assign it the right value in order to preserve sustainable business practices.

The legal framework for water determines many of the available commercial opportunities, but rapid technical advances in the field have only been accompanied by modest modifications to water-use statutes and regulations. Fracking practices today are considerably different from 2012, especially with respect to water. Current water treatment and use opportunities were barely imagined a decade ago. The management of produced water is now almost as financially important as the sourcing of water itself. Who owns this enlightenment,

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[2] See Paper No. 8, "Regulatory Framework and Associated Issues Concerning Produced Water," by David Neslin and Greg Nibert, and Paper No. 9A, "A Closer Look at Hydraulic Fracturing—An Examination of How Various States Address Fracturing Fluid Disclosure Requirements and Baseline Testing for Groundwater," by Lara D. Pringle.

[3] Keith B. Hall & Hannah J. Wiseman, *Hydraulic Fracturing: A Guide to Environmental and Real Property Issues* (2018); Davis Graham & Stubbs, LLP et al., *Hydraulic Fracturing Law and Practice* (2017). Many of these books' authors and contributors have contributed papers to this Institute.

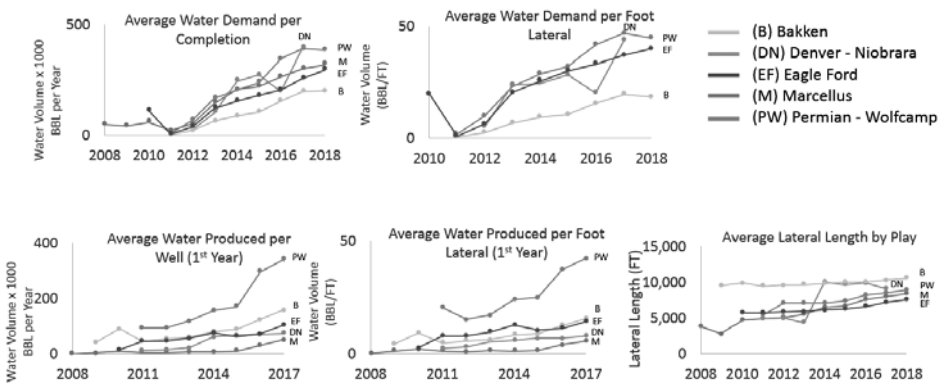
and how does society benefit from the technical achievements? Will greed stymie more progress, or will fear stifle action? Will courts muddy the waters or provide clarity? Will legislatures empower more innovation, or decide that the old ways are sacred? We are entering into interesting times for all.

From an operator's standpoint all signals suggest an increasing demand for "frack water," driven by accelerated operational consolidation and by improvements in technical practices. Water is no longer considered simply a disposable commodity or a fungible one. Instead, it is an integral part of the supply chain and the profit/loss statement of an oil and gas operator. Not all water is created equal; its financial value or impairment cost depends on its scarcity, quality, and composition. The management of water supplies for fracking operations demands costly investment in infrastructure. In some cases, it is not so clear who owns the water supply or when title to it transfers, and some emerging industry practices will challenge established legal rules and assumptions. Nearly every participant predicts that these challenges will keep the courts busy. Before we dive into legal issues, let us examine some of the industry drivers in more detail.

Figure 1 shows some simple consolidated water numbers representing five highly active US shale plays, and how they have changed in the past decade. This information has been extracted and simplified from public databases, especially FracFocus online.

Figure 1

Frac Water Demand & Produced Water Trends: Vary by Play – All Upward



Data extracted from FracFocus online information 12/2018

Clearly the demand curve shows impressive growth in water required per well-completion or "frack-job," which reflects the dramatic increase in both slick-water fracking techniques (where chemicals are added to increase flow) and the length of laterals. It also reflects the scale and intensity of operations.

Frack formulations and the volume of water they require vary considerably, depending on the properties of the geologic formation and the chemistry of its water. Since 2012–2014, the basic chemistry of fracking has evolved, motivated by cost and by exploiting the improved performance of a key additive: friction reducers. For decades, the preferred technique for hydraulic fracturing involved the use of gels or gel-producing additives such as guar to increase fluid volume and to lower viscosity in the wellbore (regulated by temperature, pressure, and chemical additives), thereby transferring pressure to the rock and imparting fractures while carrying sand into the formation to prop them open. Then, breakers (principally borates) were added to reverse the thickening of the fracking fluid. When regulators objected to the use of diesel fuel and other hydrocarbon products as gel slurrying agents, the replacement components tended to increase costs. There was another limitation: the more complex chemistry of gel fracks essentially required using only freshwater as a base fluid. Even trace amounts of boron or iron in the water could seriously interfere with the desired reactions. As freshwater became scarce and costly, and the cost of gel fracks increased, innovation became urgently desirable.

The major Texas drought of 2011–12 forced that innovation. Through advances in chemistry that enabled the use of more saline fracking fluids, brackish and produced water could be used instead of freshwater for the water base of these fluids. This advance was made possible by an improved understanding of friction reducers and their increased availability on a commercial scale. High-volume, slick-water fracking soon expanded in the Permian Basin and then became dominant. While it does use more water per well and per lateral foot than gel-based fracking, it can use 100% non-potable water sources, including highly saline produced water.

Current fracking techniques, especially slick-water fracks, can use water sourced from almost anywhere, provided that the water quality is reliably consistent within the specifications required for the particular frack chemical pack being used on location, and that water pre-treatment can be done on-site. Treatment requirements vary according to cost and the limitations imposed by physical equipment and knowledge. Water supplies can include surface waters, freshwater aquifers, brackish or saline groundwater, produced water from "conventional" operations, effluent from waste-water treatment plants, and especially water recycled from nearby unconventional oil and gas operations. Some frack chemical formulations may not be ideal for certain performance situations, and economic or logistical realities force compromises.

Managing the chemistry of water requires considerable skill, but experimentation and iterative practice in the field have greatly increased the industry's practical knowledge. Apart from concerns about environmental protection in the case of operational mishaps, operators want to prevent unwanted chemical reactions in the water such as scaling, precipitation of minerals, occlusion of flow, rapid changes in salinity or pH, the growth of microbes and bacteria, and the formation of unwanted or even dangerous gases as byproducts.

The pace and conduct of oil and gas operations affect water requirements more than anything else. Just three to five years ago, the challenge was to supply water to an operation in continuous motion at fixed speed—one rig, one wellbore, and one frack job at a time. Today's fracking practices make such a challenge seem simple by comparison. High-density drilling pads with multiple landing zones are commonplace. Instead of one wellbore at a time, operators frack several or many with advanced engineered designs that minimize the potential negative impacts of unwanted "frack hits," where a frack in one well communicates with another well. It has become normal to frack even half a dozen wellbores almost simultaneously, or keep them filled with water until the entire drilling pad has been finished. On the whole, multiple-frack operations require large amounts of water, delivered in a very short time, for an intense amount of activity followed by calm for perhaps three months or more. Oil and gas production from the whole pad is brought online quickly, with a corresponding flood of produced water. Averaging the amount of produced water on a monthly or annual basis distorts and obscures the logistical and infrastructural challenge of such peak water flow rates and volumes. Multiple-frack operations have changed the requirements for water management and have motivated collaboration across the industry.

Operators need large-scale operations to justify water infrastructure. Across the Permian Basin, water facilities have sprouted up everywhere.

Water storage capacity is key. Residence times for storage of treated produced water destined for fracking can now exceed two to three months, whereas in 2015 it was mostly less than a week for surface storage. Operators now tend to fill freshwater storage reservoirs just in time, in anticipation of well completions with less residence time for the water. Storage facilities for both fresh and produced water have become immense, holding as much as several million barrels of treated water. These facilities are designed to last for years; for produced water, storage reservoirs consist of highly engineered double- or triple-walled liners with extensive leak-detection monitoring. The more sophisticated units have elaborate water circulation and maintenance equipment to avoid secondary water quality problems—especially unwanted bacterial growth and water stratification, which can lead to layers of water with anoxic chemistry. Wind brings contaminants, and evaporation creates technical problems beyond the evaporative loss of the water itself. Evaporation rates of freshwater tend to be 5–10 times the rate of produced water, depending mostly on salinity levels.

Multiple-frack operations also require the transportation of all types of water. The most flexible and rational way to move water is through pipelines instead of trucks wherever possible. Understandably, communities object to trucks overwhelming the roads, and oil and gas operators are motivated to reduce the cost of truck transport, ideally to eliminate it altogether, thus obviating its logistical difficulties, safety challenges, and environmental risks.

Because of these concerns, multiple-frack operations have expanded water facilities and the capacity of interconnected water pipelines. At the local level, larger operators have installed pipes constructed of high-density polyethylene ("HDPE") and pumps to link gathering, treatment, and water-storage systems, or to deliver water directly to salt water disposal ("SWD") injection wells. Individual operator networks are proliferating, with some reportedly approaching about 200 miles in overall length. Some operators are doubling pipes in a given project, allowing the transport of water supplies of different quality and at different rates.

Mostly this is to separate fresh from produced water, but in some cases produced water destined for SWD is separated from produced water treated and ready for reuse in subsequent fracking operations. In addition to the trunk lines, local area lines are often used to move the highest quality treated produced water to well sites. These are frequently lay-flat hoses that resemble fire hoses. The quality and reliability of lay-flat hoses have become an issue of concern, and the American Petroleum Institute ("API") has undertaken a technical standards certification effort regarding their use in oil and gas operations. Existing API standards cover the more common tubular materials such as HDPE pipe.

Many object to pipelines, especially non-freshwater pipelines. Some of these objections can be portrayed in the press as coming from beleaguered local citizens who fear environmental damage to their properties; in some cases, these fears have real merit. But often the objections are really raised by deep-pocketed industry participants with conflicting interests, whose concerns are focused on maximizing revenue. These rivals may want to sell freshwater or water rights to freshwater. Some consider the recycling of produced water a threat to their revenue stream. Some have vested interests in competing projects. In other words, water management and pipeline access are increasingly parts of a commercially competitive business. This is not a bad thing, as it can facilitate efficient delivery of what the marketplace needs. It is naive to assume that companies and parties engaged in water supply for fracking would want the laws and regulations relating to public utilities to be applied to them. Some of these companies and parties enjoy (and exploit) legal and historical benefits traditionally associated with other water suppliers, but their use of water for oil and gas operations raise new questions of how that water usage affects the public interest—a common consideration in water law. As discussed in Section II.C, below, New Mexico has responded to these concerns explicitly.

Texas provides a good example of how oil and gas operators have exploited exceptions to the regulations governing produced water. There, the regulatory framework distinguishes between operators using or recycling water in their own operations from "commercial operations," especially those that involve SWD. Perhaps not surprisingly, but very consequentially, no oil and gas operators have applied to be recognized (and regulated) as "commercial operations"—as commercial, produced-water facilities. Instead, operators swap water with each other on a barrel-for-barrel basis, sometimes adjusting for quality. No money changes hands in a trade with other nearby or adjacent operators according to the terms, definitions, and loopholes of the Texas Railroad Commission's Rule 3.8; this barter is usually governed by a carefully crafted agreement.[4] Such agreements have led to collaboration on the timing of fracking, and the more efficient use of large-scale water treatment and storage infrastructure. They have also minimized the need for SWD, by creating a more constant demand for produced water, which in itself is an industrial goal with practical benefits. In some states that want to encourage water reuse, such swaps are not so clearly allowed without commercial permitting.

Several companies have exploited the distinction in Rule 3.8 between oil and gas operators (which receive a regulatory exception to the permit requirement for water reuse) and commercial water recyclers (which do not receive an exception)

[4] 16 Tex. Admin. Code § 3.8; *see* text accompanying notes 180–87, *infra*.

by creating subsidiary companies for water management. This distinction can simplify profit/loss cost accounting where lease ownership is shared, and may have some benefits in limiting liabilities. In 2018, an increasing number of companies seem to have sold water assets to third-party partnerships while retaining some special rights. The huge influx of capital into the water business, especially in the Permian Basin, has enabled transactions of this type. As usual, industry insiders are wondering if this capital is smart money or stupid money. Do investors have management teams that know what they are doing, and especially how variable the technical requirements for water reuse can be?

State laws and regulations regarding water rights, water-allocation practices, and especially the ownership of subsurface water resources all play a major role in defining what is legally possible and what is commercially reasonable. The legal differences regarding SWD across state jurisdictions, and the encouragement by some states to return higher-quality treated water to rivers, mean that major oil and gas producing states such as Colorado, New Mexico, Oklahoma, Pennsylvania, and Texas all have different constraints and regulatory emphases on water usage practices.

With the proliferation of produced-water recycling and its seemingly huge growth potential, the billion-dollar question is this: what treatment is needed for produced water? The answer depends upon the intended post-treatment use of the water. If the intent is to recycle the water for use as a slick-water frack into the same geological reservoir from which it came, then the produced water should require little treatment, provided the operator has fracking chemicals that are optimized for the specific chemical qualities of that local produced water supply. Most operators will add biocide. It may be cheaper to perform additional treatment to get higher performance with cheaper frack chemicals. In some situations, getting rid of iron is a good idea. These are technical and economic choices. If the operator intends to mix produced water from different sources in a pipeline, then the most important issue is scaling, and substantial pre-treatment would be required to prevent it. If the operator intends to store treated produced water on the surface for months at a time, doing so economically and efficiently will require some creative problem-solving.

Keep in mind that water quality varies considerably, depending on the geology from which the water originates and how the water may have already been used in oil and gas operations. Some reservoirs yield water that is only brackish, or less saline than seawater, such as many of the Niobrara wells of the DJ Basin in Colorado. Water from the Bakken Shale in North Dakota tends to be heavily saline, as much as eight times more saline than seawater. Permian Basin groundwater is somewhere in between—from only slightly more saline than seawater to four times as saline. The southern Midland Basin tends toward the high side of salinity, while salinity levels in the central Delaware Basin are on the lower side of that range.

Reusing produced water for oil and gas operations has proven to be cost-effective in the West. If, however, the water treatment operator seeks to treat produced water to the level necessary for "beneficial use" as western water codes define that term—for irrigation, livestock, or even human consumption—then treatment will be extensive and expensive. Treatment to that level will require large facilities, considerable energy, and sufficient space for waste products. It is important not to underestimate these costs, and the mere possibility of such

treatment and its consequences will raise the hackles of serious and thoughtful environmental scientists and policymakers. Newcomers to the water-energy nexus—especially investors from outside the oil patch—can often play down these financial, technical, and regulatory challenges, and ignore as well the vast differentials in the value of water for oil and gas production compared to that for uses such as irrigation, stock watering, and even municipal use. Until the treatment of produced water to levels fit for these and other beneficial uses can be done for pennies a barrel, there is unlikely to be rational political pressure to approve such treatment. Oil and gas operators pay more for freshwater than public water utilities would ever dream of paying. And most farmers pay little or nothing for groundwater, aside from their pumping costs.

The big driver in the water equation is really SWD availability and cost, coupled with the problems that arise when disposal volumes become very large. High SWD costs encourage the recycling of produced water. Some costs which do not seem important in the early stages of disposal can become literally seismic showstoppers. Over-pressuring shallower disposal reservoirs leads to drilling issues that add significant costs. The widespread and sustained injection of large volumes of produced water into near basement reservoirs with critically stressed faults has caused, in aggregate, an unacceptable increase in seismic activity levels in Oklahoma and Kansas.[5] So far, enhanced seismic monitoring and agency regulation in both states have substantially reduced "induced seismicity events," events known outside of the oil and gas industry as earthquakes.

Several novel trends in SWD appear likely to grow and succeed. Among these is the subsurface storage of produced water, as opposed to subsurface disposal. Subsurface storage offers several significant advantages. It can minimize overpressure by removing water from the same (underground) reservoir. It lowers the environmental risks associated with surface impoundments, because fewer impoundments are required, and it minimizes evaporation losses. The native rock in the subsurface can also act as a natural filter for the water. Best of all, area-wide well-completion practices can confidently adapt to subsurface storage supplies, because these supplies offer more predictable chemical profiles and are stored in large quantities, thus reducing contingency costs. On the negative side, some types of water stored underground will still require treatment prior to use, and operators may choose to treat those types prior to injection for storage.

Subsurface storage of produced water raises legal and regulatory issues of ownership and responsibility, and these issues loom large in the oil patch. If an operator or commercial water company injects water into the subsurface, planning to pump it out again for reuse, does that entity retain ownership of the injected water supply? How does an operator account for the mixing of produced water supplies from different sources? These issues also engage the property boundaries between mineral and surface owners. Surface owners will likely claim the right to water that is put to beneficial use, even when it might be a year or more before the water volume injected for fracking is produced at the surface. Some formations

[5] Shelby Peterie et al., "Earthquakes in Kansas Induced by Extremely Far-Field Pressure Diffusion," *Geophysical Research Letters* 45, 1395–401 (Feb. 15, 2018) (concluding that most of the earthquakes in Harper County, Kansas, since 2013 are the result of recent increases in high-volume SWD near and south of the Kansas-Oklahoma border).

almost never give back this water entirely. The issues become even more complex when freshwater rights are involved.

II. THE LEGAL DIMENSIONS

A. Water Law Basics for Oil and Gas Production

The jurisdictional and doctrinal variety of water law and water rights regulatory procedure across the United States can intimidate lawyers who do not specialize in the field. However, oil and gas lawyers generally enjoy an advantage, since oil and gas law abounds with similar theoretical, common-law, and statutory variety. Four questions can serve as an overall guide for practitioners who are tasked with resolving the main legal and regulatory challenges presented by their client's search for a secure water supply for fracking operations:

1. *Source.* What is the geophysical source of the water to be used in fracking operations?
2. *Definition.* How does the state define and categorize the water resource at its source?
3. *Power, Permitting, and Procedure.* What state governmental entity (or entities) has (or have) jurisdiction over the use and permitting of the water supply both at its source and its place of use?
4. *Use Rules.* What legal doctrine or doctrines apply to the use of the water resource? And how do internal hierarchies and exceptions qualify (and even effectively eliminate) elements of that doctrine?

This section proceeds through these four questions by providing answers according to the principal varieties of state law, and by showing how these questions are often interdependent. This method strikes the author as a good place to begin, before embarking upon a survey of state water laws. For example, Colorado and Kansas define their groundwater supplies in different ways, and apply different jurisdictional and procedural regimes for surface and groundwater, even as they both qualify as states that generally follow the prior appropriation doctrine. Similarly, Colorado, New Mexico, and Nebraska have enshrined that doctrine in their respective constitutions, but that similarity means practically little compared to their divergent regulatory approaches to groundwater. Finally, the basic doctrinal divide between western, prior appropriation doctrine states and eastern, riparian doctrine states has been lessening of late, with western states adopting aspects of "reasonable use" which are the hallmark of riparian states, while eastern states have embraced permitting regimes which are traditionally associated with prior appropriation states. Because many practitioners serve clients with fracking operations in multiple states, it is important to recognize—just as with oil and gas law—the importance of state law diversity.

1. Source

This is probably the easiest question to answer: what is the geophysical source from which the water to be used in fracking operations originates? Water obtained from rivers, streams, springs, lakes, reservoirs, ponds, and playas is water that originates from a surface water source, and water obtained from underground is water that originates from a groundwater source. (This seems so obvious as to justify the low wages earned by water lawyers compared to oil and gas lawyers.)

But this is usually not the end of the inquiry: some surface waters do not actually qualify as surface water under state law! And regarding groundwater, two further questions are generally necessary. First, what is the specific geohydrological characteristic of the aquifer—is it an alluvial aquifer, closely connected hydrologically to overlying springs, creeks, and rivers, such as the Edwards Aquifer in Texas, or is it more distant from surface water supplies, such as much of the High Plains-Ogallala Aquifer, or the deeper (and much more saline) Dakota Aquifer? Second, if the source of water supply is an alluvial aquifer, is the point of diversion—the wellbore that accesses the water supply—in close proximity to a stream or river, or is it more distant?

All of these water sources—surface supplies, alluvial groundwater supplies, and deeper, non-alluvial groundwater supplies, both fresh and saline—have their respective advantages and disadvantages. This is especially the case in the West. In most western states, surface water supplies enjoy the most senior priorities under the prior appropriation system, but the availability of water for all but the most senior surface rights can vary significantly from year to year. By contrast, groundwater rights are generally junior to most surface rights, but water supplies held in groundwater formations such as the Ogallala Formation are generally more dependable, cleaner, and more consistent in their chemistry than surface supplies, making them more attractive to oil and gas producers who need uniform supplies for their fracking formulas. Obviously, in many areas, the oil and gas operator will not have its choice, and will be limited by the water supplies and groundwater formations near the fracking operation. But because many oil and gas companies pursue shale plays in a variety of geohydrological contexts within the same state, their lawyers need to understand that the legal rules that apply to one source of supply may not, and most likely will not, be the same as those that apply to another. For example, an oil and gas company pursuing a fracking operation in Weld County, Colorado, seeking water from a surface or alluvial groundwater source within the South Platte River Basin, will face different doctrinal, jurisdictional, and procedural rules than the same company pursuing a similar operation to produce oil and gas from the Niobrara Formation in Sedgwick County, an operation that will require water from the High Plains-Ogallala Aquifer in northeastern Colorado.

2. Definition

The source question leads to the second question, the definition question: how does the state define and categorize the water resource at its source? This is a distinct question because the hydrological categories of water supply are not necessarily congruent with the legal categories under state water law; indeed, as with many aspects of natural resources law, legal conclusions and statutory definitions and concepts (such as trespass) are often at odds with geophysical reality. But that makes them no less important. The standard legal definitions of the water supply source generally fall into the following categories.

a. Surface Water Supplies

Because surface water supplies were the first supplies to be developed, these supplies undergird the conceptual base of American water law, both in the riparian East and the prior appropriation West. In the East, industrialization, water power, and urbanization combined to put new pressures on surface water usage during the

nineteenth century, forcing substantial changes in riparian water law. In the West, the climatic condition of permanent aridity and the topographical condition of rivers and streams located distant from arable land combined to generate the prior appropriation doctrine. Across the country, surface supplies are generally the "default" category of water supply upon which much water law is predicated.

However, it is important to review the specific statutory and common-law definitions for surface water, because some surface water supplies may not be legally defined as such. For example, Oklahoma defines water flowing in a definite channel as "stream water" and water from a "stream system" or "stream sub-system" as subject to appropriation under the prior appropriation doctrine, but the Oklahoma Water Resources Board ("OWRB") regulations that define these terms also define water that flows over land without forming a definite channel as "diffused surface water," water that belongs to the landowner with no apparent statutory restrictions.[6] Similarly, in Texas, "state water" does not include diffuse rainwater or surface water prior to its passage into a natural watercourse; such water belongs to the owner of the land where it is gathered, so long as it remains on that land.[7]

b. Groundwater Supplies

By contrast, the development of groundwater in substantial supplies, and its attendant development in property and regulatory law, is relatively recent. While the use of artesian water supplies in locations such as the San Luis Valley of Colorado, the Pecos River Basin in New Mexico, and across Nebraska date back to the nineteenth and early twentieth centuries, such usage was made possible by artesian pressure itself—pressure which has since largely dissipated due to post-World War II groundwater depletion.[8] Elsewhere, it took the infrastructural and technological advances of the 1930s and 1940s—rural electrification, the submersible centrifugal water pump, and center-pivot irrigation—to make the lifting of groundwater supplies from the High Plains-Ogallala Aquifer and other unconfined aquifers economically feasible for irrigation.

This historical background is relevant for three reasons, especially in the West. First, since large-scale groundwater development lagged behind surface water development by nearly a century, states struggled for decades with the question of whether and how to incorporate groundwater within their existing legal regimes, which had developed under the assumption of predominantly surface water supplies. In other words, was groundwater part of the "waters of the state" dedicated to the public, and subject to appropriation as private water rights, or was it a private resource similar to oil and gas? Second, since irrigation and other agricultural use accounts for the overwhelming majority of groundwater use in the West, states have more recently wrestled with how to incorporate non-agricultural uses—most prominently municipal uses, and industrial uses such as fracking—within groundwater regimes whose legal rules were developed primarily for

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[6] Okla. Stat. tit. 82, § 105.1(1); Okla. Admin. Code § 785:20-1-2.

[7] Domel v. City of Georgetown, 6 S.W.3d 349, 353 (Tex. App.—Austin 1999).

[8] *See, e.g.*, Colo. Rev. Stat. § 36-3-120(3) (concerning the duties of settlers who have proved up irrigation works, including artesian wells, pursuant to the federal Carey Act of 1894); N.M. Stat. § 73-1-24 (affirming the powers of artesian supply districts established under prior law) (N.M. Laws 1941, ch. 98, § 1); Neb. Rev. Stat. § 46-281 (prohibiting the waste of artesian water supplies) (Neb. Laws 1897, ch. 84, § 1).

agriculture. Finally, while most of the nation's oil and gas supplies exist in rural areas dominated by agriculture, fracking has become more and more present in the West's burgeoning suburban and exurban areas—areas whose groundwater supplies have been the subject of exceptional legal classifications.

i. States that define all groundwater supplies the same way

Most western states place all of the groundwater within the state under the same legal classification and doctrinal regime. Idaho, Kansas, Montana, New Mexico, Utah, and Wyoming are examples of prior appropriation states that do not generally distinguish between alluvial and non-alluvial groundwater supplies. Texas places almost all of its groundwater supplies under the rule of capture. Oklahoma used to place all of its groundwater supplies under the prior appropriation doctrine, but abandoned that system in favor of a modified rule of capture; in either case, it does not distinguish between types of groundwater. California maintains different systems of water rights to groundwater, but those rights apply to all of the state's groundwater generally. Most of the eastern, riparian states treat all groundwater supplies the same way.

ii. States that have enacted or established important legal distinctions between different types of groundwater supplies

To the hydrogeologist and the layman alike, groundwater is water that resides under the ground. But in several jurisdictions across the West, the law does not obey such simplicity, and instead has established different categories of groundwater.

The first and broadest category is what most people would understand as groundwater: water located in unconfined aquifers, supplied by precipitation and stream seepage, and supplying in turn streams and rivers. But a second category exists for alluvial groundwater supplies that are so near the channel of a stream or river that the law has declared them to be part of those surface waters. In Arizona, the first category is known as "percolating groundwater," and may be pumped by the overlying landowner subject to the (riparian) doctrine of reasonable use.[9] The Arizona name for the second category of groundwater is "subflow," which is not a scientific or hydrological term, but rather a legally constructed term that includes those waters that are immediately adjacent to a stream, and "are themselves part of the surface stream."[10] Because "subflow" is thus essentially indistinguishable from surface streams, it is appropriable as surface water under the Arizona statutes for surface water supplies, which have adopted the prior appropriation doctrine.[11] Because Arizona law presumes underground waters to be percolating groundwater, and thus not appropriable as subflow, one who asserts that underground water is a part of a stream's subflow (and therefore appropriable as surface water under the prior appropriation doctrine) must prove that fact by clear and convincing evidence.[12] Nebraska follows a similar system as Arizona, but on a much smaller

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[9] Bristor v. Cheatham, 255 P.2d 173 (Ariz. 1953).

[10] Maricopa Cnty. Mun. Water Conservation Dist. No. One v. Sw. Cotton Co., 4 P.2d 369, 380 (Ariz. 1939).

[11] *In re* General Adjudication of All Rights to Use Water in the Gila River System & Source, 9 P.3d 1069, 1073–74 (Ariz. 2000).

[12] *In re* General Adjudication of All Rights to Use Water in the Gila River System & Source, 857 P.2d 1236, 1246 (Ariz. 1993).

and more defined scale. Wells that are within 50 feet of a running stream are treated as diversions of surface water supplies under the prior appropriation doctrine, but wells located beyond that distance are treated as groundwater wells, subject to the riparian doctrine of reasonable use.[13] Texas defines "state water" as comprising surface water bodies, but includes within that definition groundwater "underflow," which, like surface waters in Texas, is appropriated under the doctrine of prior appropriation.[14]

The third category of groundwater resides at the other end of the hydrological spectrum: non-alluvial groundwater that is so distant from the channel or alluvium of a stream or river that the law has declared such groundwater to be a distinct source. This distinction arose in response to the groundwater revolution of the 1950s and 1960s and became a distinctive feature of Colorado water law. In 1969, Colorado defined "waters of the state" to include groundwater supplies that are tributary to natural streams. This "tributary groundwater" is regulated in generally the same way as surface waters, pursuant to the doctrine of prior appropriation, and under the jurisdiction of the State Engineer.[15] The other major type of groundwater was labeled "designated groundwater"—groundwater that did not overlie a river or stream, such as the portions of the High Plains-Ogallala Aquifer in eastern Colorado, where pumping groundwater does not quickly affect surface flows.[16] Designated groundwater, as will be discussed below, is subject to a modified form of the prior appropriation doctrine and does not fall under the jurisdiction of the State Engineer.

The fourth category concerns groundwater supplies that have received special legislative status due to their status as over-appropriated water supplies or their value as municipal water supplies. Again, this appears to be a special creature of Colorado water law. Groundwater supplies in this third sub-category are defined under Colorado law as "nontributary" and "not nontributary," and include the stacked aquifers within the Denver Basin, which supply water to the newer suburban communities along the Front Range. Nontributary groundwater is neither tributary groundwater nor groundwater that is located within a designated groundwater basin. It is statutorily defined in terms of depletion effects, as water, the withdrawal of which will not, within 100 years of continuous withdrawal, deplete the flow of a natural stream, at an annual rate greater than one-tenth of 1% of the annual rate of withdrawal.[17] Because of their high economic value as municipal water sources, the Colorado legislature has declared that the ownership of these water resources is connected to the overlying land, with a 100-year depletion period.[18]

As discussed in the next two subsections, the category of water supply generally determines the most important jurisdictional, doctrinal, and regulatory aspects of how that water can be obtained and used for fracking operations.

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[13] Neb. Rev. Stat. § 46-637.

[14] Tex. Water Code Ann. § 11.021.

[15] Water Rights and Determination Act of 1969, Colo. Rev. Stat. § 37-92-103(13); Colorado Ground Water Management Act of 1965, Colo. Rev. Stat. § 37-90-137.

[16] Colo. Rev. Stat. § 37-90-103.

[17] *Id.* § 37-90-103(10.5).

[18] *Id.* §§ 37-90-102(2), -103(10.5)–(10.7).

3. Power, Permitting, and Procedure

Having identified the preferred (or only) water source for its fracking operations, and having further identified how state law (including administrative regulations) has defined that water source, the next question to pursue is this: what state governmental entity (or entities) has (or have) jurisdiction over the use and permitting of the water supply both at its source and its place of use?

Where the relevant state places all of the water within the state (both surface and groundwater) within the control of a state agency, then that agency and its chief officer, usually the state or chief engineer, shall be responsible for permitting.[19] However, even in states that have a unified jurisdictional system for both surface and groundwater, that is not necessarily the end of the inquiry. For example, in Kansas, the Chief Engineer of the Kansas Department of Agriculture, Division of Water Resources ("KDWR"), exercises jurisdiction over all water rights and permits, but that exercise often takes place in tandem with local groundwater management districts, which enact local groundwater management plans that are subject to the approval of the Chief Engineer.[20]

Where the relevant state has established different jurisdictional domains for surface and groundwater, and the desired water source is defined as a surface water source, the answer to this third question is also fairly straightforward: the state will have jurisdiction, and the state officer in charge of water resources (such as the state water board or the director of the state's natural resources agency) will be the supervisor of the permitting process for rights to surface water.[21]

Where the relevant state has established different jurisdictional domains for surface and groundwater, and the desired water source has been legally defined as groundwater, then the answer is more difficult to generalize. The following is a skeletal summary of some of these jurisdictional divisions regarding groundwater in western states.

As we have seen, Colorado distinguishes tributary groundwater from other types of groundwater (designated groundwater, nontributary groundwater, and not nontributary groundwater). Jurisdiction over tributary groundwater remains, as with surface water, with the State Engineer of the Colorado Division of Water Resources ("CDWR").[22] Jurisdiction over designated groundwater, on the other hand, lies with the Colorado Groundwater Commission, which issues well permits, but significant powers also rest within local groundwater management districts.[23]

Nebraska has never claimed central authority over regulating groundwater; local control of groundwater has always been the law. While the Nebraska Department of Natural Resources controls surface water and water rights,

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[19] *See, e.g.*, Kan. Stat. Ann. §§ 82a-706, -711 (granting the authority for granting water rights to the Chief Engineer of the Division of Water Resources); Utah Code Ann. § 73-2-1 (doing the same for the State Engineer).

[20] Kan. Stat. Ann. § 82a-1020 *et seq.* (Groundwater Management District Act).

[21] *See, e.g.*, Neb. Rev. Stat. § 61-205 (granting to the Director of the Department of Natural Resources authority over surface water rights and diversion works); Okla. Stat. tit. 82, § 105.12 (granting authority over surface water rights to the Oklahoma Water Resources Board); Tex. Water Code Ann. § 11.121 (placing authority for granting permits for the use of "state water" (that is, surface water) to the Texas Commission on Environmental Quality).

[22] Colo. Rev. Stat. §§ 37-92-103(13), 37-90-137.

[23] *Id.* §§ 37-90-109 to -143, -104(3)(b), -111.5, -130(2)(j).

groundwater is governed by a different set of laws and administered by natural resources districts, which are large, multi-county state subdivisions.[24]

Texas and Oklahoma are significantly different. In Texas, landowners hold the property right in the groundwater beneath their land.[25] Texas groundwater is not part of the "waters of the state" as is surface water.[26] So, while groundwater in Texas is not within the jurisdictional domain of the Texas Commission on Environmental Quality ("TCEQ"), significant regulatory authority has been conferred upon Groundwater Conservation Districts ("GCDs") that, among other things, are responsible for permitting water wells, which generally must be permitted.[27] In Oklahoma, groundwater is also considered private property, not waters of the state, and so belongs to the overlying surface owner, subject to state regulation.[28]

4. Use Rules

Having identified the relevant permitting agency (or agencies, such as local groundwater districts) whose approval will be required to obtain a water right or permit for the use of water for fracking, the next question concerns what legal doctrine or doctrines apply to the use of the relevant water resource. Within that inquiry is the issue of whether there are internal hierarchies and exceptions that qualify (and even effectively eliminate) elements of that doctrine. As we have seen, matters of jurisdiction are usually intertwined with matters of water law doctrine.

a. Prior Appropriation

The prior appropriation doctrine first developed in California and Colorado, and became recognized under federal mining and homesteading law during the post-civil war period; by the late nineteenth century, it had become the central water law doctrine for the western states. Greatly simplified, the doctrine can be reduced to two principal components. The first is priority: as so many western water codes proclaim, "first in time, first in right."[29] In times of shortage, the holder of a senior water right has the legal right to use all of the water authorized under that right, and junior right holders generally cannot fulfill their rights until the senior rights have been satisfied. Similarly, if water use pursuant to a junior right or rights is interfering with (or "impairing") a prior right, then the holder of the prior right can obtain an order from the State Engineer requiring the holders of those junior rights to cease their diversions until the senior right is satisfied. In other words, there is no "sharing of the shortage."[30] (This is in marked contrast to

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[24] Neb. Rev. Stat. §§ 2-3212(1), 46-702.

[25] Edwards Aquifer Auth. v. Day, 369 S.W.3d 814 (Tex. 2012).

[26] *See* text accompanying note 14 *supra.*

[27] Tex. Water Code Ann. § 36.113.

[28] Okla. Stat. tit. 82, §§ 1020.1, .3.

[29] *See, e.g.*, Kan. Stat. Ann. § 82a-707(c); Neb. Rev. Stat. § 46-204; Wyo. Stat. Ann. § 41-3-101.

[30] An important qualifier: some prior appropriation states, such as Nebraska and Texas (for surface water), and Wyoming (for both surface and groundwater), have adopted hierarchies of beneficial use preferences within the prior appropriation system. Use-preference states fall into two categories: those which apply the preference only at the time of agency review of the water rights application, and those which apply the preference in administering water rights in times of shortage. Texas follows the former approach. *See* text accompanying notes 114–16, *infra*.

the reasonable use/correlative rights doctrine, which accounts for many factors and balances equities in times of shortage.) The second principal component is severability: water that is diverted from a stream or aquifer can be put to beneficial use on the property where the point of diversion is located, but it can also be used elsewhere, whether on an adjacent farm, in a nearby town, or hundreds of miles away, as with the municipal supplies of Los Angeles and Denver. Because prior appropriation rights have always been severable from the land, they are generally more marketable than reasonable use/correlative rights water rights.

Prior appropriation rights generally have five principal attributes. The first two are (1) priority (the date of the first appropriation of water) and (2) authorized quantity (usually measured by rate of diversion and annual total use). The priority of a water right is fixed. One who buys an 1869 water right in 2019 receives the benefits of that 1869 priority; this is why older rights are more valuable than junior rights. The authorized quantities of a prior appropriation right also remain fixed, unless the holder of the right (or a successor in interest) changes other attributes of the right. The remaining three attributes of a prior appropriation right are (3) point of diversion, (4) place of use, and (5) type of beneficial use. The point of diversion is the geographical location from which the water supply is removed from the source of supply, such as a pump or flume from a river, or a well from an aquifer. The point of diversion can be changed, providing that it does not impair existing water rights, regardless of priority. For example, it is not permissible to move from an old well with a 1960 priority to a new well whose cone of depression impairs a nearby well with a 1970 priority; junior rights are entitled to the conditions of the water supply that were in place at the time of appropriation. The place of use is, obviously, where the water is put to beneficial use. For most groundwater irrigation rights, the place of use is the circle of irrigated ground. The place of use can also be changed; but again, that change cannot impair existing rights. The final attribute of a prior appropriation right is the type of beneficial use. Because there is no legal right to waste water—to put water to a use that is not beneficial—the state must recognize the type of intended use as beneficial. This attribute can also be changed, provided it does not impair existing rights. When the type of beneficial use changes from a less consumptive use to a more consumptive use, the state will reduce the annual authorized quantities of the water right accordingly. In most western states, the State Engineer reviews applications for all such changes; in Colorado, they are reviewed and occasionally litigated in Colorado's water courts.

To understand a prior appropriation right in context, consider the following simplified hypothetical example of how an irrigation water right in Kansas becomes a fracking water right.

Jed Smith owns a quarter-section of irrigated farm ground. According to his certified water right, his right contains the following attributes: (1) File No. 2980, with a priority of January 3, 1952; (2) authorized quantities of 800 gallons per minute (gpm) maximum, and a maximum annual authorized quantity of 240 acre-feet; (3) a point of diversion that is legally described as the point 100 yards due south of the northeast corner of his SW ¼ of Section 33, Township 11, Range 11 East of the Principal Meridian, Finney County, Kansas; (4) a place of use that is the center-pivot circle of 125 or so acres within that quarter section; and (5) its type of beneficial use is irrigation. Smith is a farmer who uses an old center-pivot irrigation system. Of the 240 acre-feet he pumps a year, about 50% is consumed by his corn crop. The remaining 50%, or 120 acre-feet, returns to the ground as

recharge. Other center-pivot-irrigated farms surround Smith's quarter section, but they have junior priorities.

Ritch Industrial Enterprises ("Ritch") needs water for its fracking operations in Finney County. These will be long-term operations, probably lasting decades ("or so long as oil and gas is produced . . . ."). Because Ritch needs a long-term water supply, and there is no water left to appropriate in that part of the state, Ritch needs to purchase a water right. It decides to purchase Smith's water right, largely because of its senior priority in the water neighborhood. Smith's well is a good producer, because it draws from the alluvium of the Arkansas River. Ritch's leases and its major frack sites are two miles away from Smith's farm. It plans to expand its holdings in Finney County over the next several years. Having purchased (or contracted to purchase) Smith's water right, Ritch will need to apply for and obtain approvals from the Chief Engineer of KDWR to change some of the attributes of Smith's water right. Recall the list of the attributes of a prior appropriation right:

(1) *Priority.* This cannot be changed; indeed, it is the main reason why Ritch has purchased Smith's right. It will remain as File No. 2980, with a priority date of January 3, 1952.

(2) *Authorized quantities.* This is the most important, and frequently most challenging, aspect of a change in a prior appropriation right. Keep in mind that although this right is senior to others in the neighborhood, it cannot be changed in such a way that injures other existing rights—regardless of priority. This is known as the "no-injury" rule.[31] Recall that the Smith farm is surrounded by other farms with similar, if junior, irrigation rights, and that Smith's consumptive use of his 240 acre-feet is 50%. Ritch will be using this water supply for fracking—a use that administrative regulations will probably define as a 100% consumptive use, since that water will stay deep underground (or return as a waste product; more on this later). Because the Chief Engineer will enforce the no-injury rule, he will likely make his approval of the change conditional upon Ritch accepting a reduction in the annual authorized quantity of the water right from 240 acre-feet to 120 acre-feet. Under this reduction, the total water diverted decreases by 50% (from 240 to 120 acre-feet) but the consumptive use total stays the same (50% of 240 = 100% of 120 = 120 acre-feet). This is an important lesson. When evaluating the quantities of water necessary for a fracking operation, the most important number is not the gross figure of annual diversion, but the net figure, the consumptive use component of that gross figure.

(3) *Point of Diversion.* Because the Smith well is a good well, fully bottomed in the alluvial aquifer of the Arkansas River, Ritch will not change this attribute. (However, Ritch will need, as part of its purchase of the water right, to obtain an easement to access the well on Smith's property.)

(4) *Place of Use.* This will need to change, from Smith's farm in the SW ¼ of Section 33 to a place of use two miles away. Because water will no longer be applied to Smith's farm, some, if not all, of Smith's neighbors (with their junior rights) will suffer, because Smith's low-efficiency irrigation system returned 50% of his gross water pumped back into the water table, helping supply his neighbor's wells. Thus, the Chief Engineer, for the reasons more fully explained in (2) above, will reduce the authorized quantity of the right by 50%. Other than the change in

[31] *See, e.g.*, Kan. Stat. Ann. § 82a-708b; *see also* Farmers Highline Canal & Reservoir Co. v. City of Golden, 272 P.2d 629 (Colo. 1954).

authorized quantity, the change in the place of use should not be controversial. Ritch can probably designate the place of use across several frack sites.

(5) *Type of Use.* Ritch will need to change Water Right File No. 2980 from irrigation use (a recognized beneficial use) to industrial use (also a recognized beneficial use). Again, because the right is changing from a 50% consumptive use to a 100% consumptive use, approval from irrigation to industrial use will require the 50% reduction in the annual authorized quantity of the changed right.

So, assuming Ritch obtains DWR approval for the change, the changed water right will have the following set of attributes:

(1) Priority: File No. 2980, January 3, 1952
(2) Authorized quantities: 800 gpm, 120 AF/year
(3) Point of Diversion: the point 100 yards due south of the northeast corner of his SW ¼ of Section 33, Township 11, Range 11 East of the Principal Meridian, Finney County, Kansas (the same as Smith's);
(4) Place of use: a legal description of the Ritch leases, as well as the specific (if possible) fracking sites; and
(5) Type of Use: Industrial.

Ritch now has a permanent, real property right in the use of water for its fracking operations, for 2019 and beyond. In times of shortage, where Ritch believes its well is being impaired by junior rights, it will have the ability to "make a call" and request the Chief Engineer to shut down junior water rights in its water neighborhood.[32] If it decides to move its fracking sites, or assign or farmout its existing leases and lease new ground near the well, it will need to obtain approvals for the change in place of use.

This example illuminates one of the major reasons why western states have developed temporary water use permits for oil and gas operations that skirt some of these rules—because the process of obtaining water rights can be cumbersome and difficult. But as we have seen in Section I above, fracking has become the predominant method of oil and gas production, and oil and gas operators are increasingly seeking out longer-term water supplies. That search will likely require securing water rights, and not just temporary permits.

Let us now turn to the two other water law doctrines in the United States.

b. Riparian: Reasonable Use/Correlative Rights

The riparian doctrine of Reasonable Use/Correlative Rights does not apply to surface waters in the western states, but it remains the operative doctrine for groundwater in Arizona, Nebraska and California, and in part of the Rio Grande Basin in Texas.[33] It is the general rule, with many variations, for the eastern states,

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[32] If Ritch were operating in a prior appropriation state that has adopted a hierarchy of use preferences, its ability to make such a call may (or may not) depend upon whether there are water rights in the neighborhood that have beneficial uses ranked above industrial use; *see* note 30 *supra*. Because Kansas law does not contain a use preference, that does not trouble Ritch here.

[33] *See, e.g.*, Bristor v. Cheatham, 255 P.2d 173 (Ariz. 1953); Ostermann v. Cent. Neb. Pub. Power & Irrigation Dist., 268 N.W.2d 334 (Neb. 1936); Spear T Ranch v. Knaub, 691 N.W.2d 116 (Neb. 2005); Katz v. Walkinshaw, 74 P. 766 (Cal. 1903). In a large portion of the Rio Grande Basin in Texas, surface water rights are allocated based on correlative rights and managed by a water master. State v. Hidalgo Cnty. Water Control & Improvement Dist. No. 18, 443 S.W.2d 728 (Tex. 1969); Tex. Water Code Ann. § 11.3271.

both for surface and for groundwater.[34] Under the doctrine, the reasonable use of water is an inherent common law attribute of riparian property: property that abuts a stream river, lake, or other surface water course, as well as property that overlies a groundwater formation.[35] Each adjoining or overlying landowner has an equal and correlative right to make reasonable use of that water—on the landowner's riparian land. Like a prior appropriation right, a riparian right is a usufructuary right: the right to use water, subject to the rights of other riparian owners both upstream and downstream to use the water in a similar reasonable fashion, and not the ownership of the water itself.

The common law riparian doctrine presents a number of challenges to oil and gas producers seeking water supplies for fracking operations. While states have addressed some of these challenges by displacing that common law through statutory permitting programs, these challenges can still remain. Four aspects of the riparian doctrine are noteworthy here.

The first two aspects are those of quantification and type of use. Recall that the prior appropriation system quantifies rights and recognizes types of beneficial uses: the example of Ritch above shows that Ritch holds a water right entitling it to 120 acre-feet of water annually, for the beneficial use of industrial use. Such quantification and categorization do not clearly exist under the riparian doctrine. Its quantum and category are vaguely captured as "reasonable use": a riparian owner may make any and all uses of the water, so long as it does not unreasonably interfere with other riparian owners' ability to make reasonable use of their waters as well. This raises two obvious questions. How much use is unreasonable? And under what circumstances is the type of use—fracking—unreasonable as well? The answer to both questions depends upon the weighing and balancing of factors and equities between the prospective user and other riparian owners. What constitutes "reasonable" in either case (amount and type of use) is determined on a case-by-case basis.[36]

The third relevant aspect of the riparian doctrine concerns severability. Again, recall that severability is a distinctive characteristic of the prior appropriation doctrine: Ritch, in our example, has the explicit legal right to move water pumped from its well on Smith's farm and pipe it to its fracking operations two miles away. Riparian doctrines are not so clear, and have been traditionally hostile to the right to transfer water from riparian land. Older eastern cases have treated off-land transfers as unreasonable as a matter of law, while more modern cases have viewed transfers as less favored compared to on-land uses.[37]

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[34] For an excellent (if slightly older) summary of the riparian doctrine and water rights and water regulation in the eastern states, with particular attention to the Marcellus Shale, see R. Timothy Weston, "Water Supply and Wastewater Challenges in Marcellus Shale Development," 30 *Energy & Min. L. Inst.* 15-1, § 15.03 (2009).

[35] Wear v. State of Kansas *ex rel.* Brewster, 245 U.S. 154, 157 (1917). (Kansas abandoned the riparian doctrine in 1945, becoming a comprehensive prior appropriation state for both surface and groundwater with the enactment of the Kansas Water Appropriation Act.)

[36] For a comprehensive review of this balancing approach, see 1 *Waters and Water Rights* §§ 7.02–.03 (Robert E. Beck & Amy K. Kelley eds., 2011); *see also* Restatement (Second) of Torts § 850A (outlining the factors involved in determining reasonable use).

[37] *See* Weston, note 34 *supra*, at 6; Mich. Citizens for Water Conservation v. Nestle Waters N. Am. Inc., 709 N.W.2d 174, 196 (Mich. Ct. App. 2005).

The final relevant aspect of the riparian doctrine concerns groundwater or, put another way, the three subsidiary doctrines for groundwater within riparian law.[38] Under the "English Rule," the riparian landowner may withdraw as much groundwater as he wishes, without liability to neighboring landowners—effectively a rule of capture. Of the eastern riparian states, only Maine follows this rule.[39] The second rule, the "American Rule," is the prevalent doctrine for the states overlying the Marcellus Shale. Like the English Rule, the American Rule allows nearly unlimited use of groundwater made upon the landowner's land, but regarding off-land use, such use is allowed only up to the point where it begins to injure other riparian owners who pump from the same aquifer.[40] The third reasonable use doctrine for groundwater is that of correlative rights, which is the principal groundwater doctrine in California. Under the correlative rights doctrine, landowners above an aquifer have an equal right to put the water to beneficial use on their lands, but they cannot substantially impair their neighbors' use of their own underlying supplies.[41]

All four of these aspects of the common law riparian doctrine present substantial challenges to the oil and gas developer in eastern states (as well as for groundwater in California, an important oil and gas state). Where a state jurisdiction is hostile to off-site uses of surface and groundwater, the developer may face considerable challenges in obtaining water supplies for fracking. Because these aspects present such obvious obstacles, several eastern states have adopted statutory permitting programs that displace the common law.

c. Rule of Capture/Modified Rule of Capture for Groundwater

Oil and gas practitioners are no strangers to the rule of capture, the fundamental rule in American oil and gas law. They know that the rule of capture is not the law of the jungle: the restraints of the common law, of correlative rights, and of the state's police power have substantially domesticated the rule in practice. It remains to be seen whether the same can be said for the two oil and gas-producing states that have adopted the rule of capture for groundwater: Oklahoma and Texas.

Oklahoma follows a modified rule of capture for groundwater, where landowners are entitled to an "equal proportionate share" of the groundwater beneath their land.[42] As the term indicates, that allocation is generally equal to the proportion of land which landowners own above the relevant groundwater basin. Landowners must obtain a permit from the OWRB to exercise their rights to that proportionate share.[43] That share is based on a determination of the "maximum annual yield of groundwater" based upon a minimum basin or subbasin life of

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[38] Eastern courts rarely treat these doctrines in isolation, and often produce hybrids of their own.

[39] Maddocks v. Giles, 728 A.2d 150, 153 (Me. 1999).

[40] *See* Weston, note 34 *supra*, at 6–7 (discussing Mich. Citizens for Water Conservation v. Nestle Waters N. Am. Inc., 709 N.W.2d 174 (Mich. Ct. App. 2005)).

[41] This approach is substantively similar to the "equal proportionate share" approach adopted in Oklahoma; from a theoretical standpoint, the line between the correlative rights doctrine and modified rule of capture can be quite difficult to discern.

[42] Okla. Stat. tit. 82, §§ 1020.2, .6.

[43] *Id.* §§ 1020.5, .7, .9.

twenty years from the date of the board's order establishing the final determination of that yield.[44]

Texas is famous—or rather infamous—for maintaining a firm adherence to the rule of capture for groundwater, which generally aligns with the "ownership in place" theory for oil and gas in Texas.[45] Landowners own the groundwater supplies underneath their land.[46] They thus have the right to withdraw as much water as they deem appropriate, even if it causes the impairment of wells on adjacent land; the only common-law constraints that the Texas Water Code recognizes are those of waste, malice, and pumping that causes land subsidence.[47] Neighbors suffering impairment have the same recourse that adjacent oil wells suffering drainage do: the correlative right to pump water just as freely.[48]

But Texas groundwater law may not be as Hobbesian as it first appears. Like Nebraska, Texas has expressly delegated the management of groundwater to local districts, Groundwater Conservation Districts ("GCDs").[49] GCDs have the power to make rules for the pumping and management of groundwater,[50] and to enforce those rules by injunctive relief and civil penalties.[51] (As we will see in Section II.B below, however, those rules are not consistent across different GCDs.) GCDs are also required to develop groundwater management plans, which must be approved by the Texas Water Development Board.[52] Thus, the rule of capture for groundwater in Texas has the same general constraints as the rule of capture for oil and gas: the common law, correlative rights, and the police power of the state, as delegated to the GCDs.

B. Permitting Requirements and Permitting Exceptions

1. The Permitting Requirement Generally

As the summaries of Section II.A reveal, obtaining real property rights in the use of water or in the water supply itself can present a number of difficulties and complications for the oil and gas producer. Producers are substantially different water users from irrigators, and have substantially different needs. The geophysical aspects of water usage for oil and gas production are also different, especially regarding fracking. Irrigation applies very large amounts of water to the surface, and generates modest return flows to the surface and recharge to groundwater. Fracking injects comparatively less water into deep hydrocarbon formations, but generates substantial amounts of produced water back to the surface, water that must be disposed of by injection into deep formations, recycled for subsequent use, or released, post-treatment, into surface waters. Because of these distinct operational differences in the use of water, courts have regularly wrestled with how to reconcile such usage with legal regimes that are predicated upon agricultural usage. These exceptional aspects of water use, and the much

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[44] *Id.* § 1020.5.

[45] Sipriano v. Great Spring Waters of America, 1 S.W.3d 75 (Tex. 1999).

[46] Tex. Water Code Ann. § 36.002(a); Edwards Aquifer Auth. v. Day, 369 S.W.3d 814 (Tex. 2012).

[47] Tex. Water Code Ann. § 36.002(b)(1).

[48] Houston & T.C. Ry. Co. v. East, 81 S.W. 279, 281 (Tex. 1904).

[49] Tex. Water Code Ann. § 36.002(d)(1)–(2).

[50] *Id.* § 36.101.

[51] *Id.* § 36.102.

[52] *Id.* §§ 36.1071, .1072.

greater economic value of water used for oil and gas production compared to irrigation, have led state legislatures and state agencies to establish distinct permitting regimes for water usage related to oil and gas production. This section provides an overview of several typical state law permitting regimes for that usage—regimes that vary in their consistency with and departure from the standard laws and doctrinal rules that apply to other uses of water in that state. The laws and regulations related to fracking operations comprise a significant exception to those standard laws and rules.

a. Colorado

i. The basic permitting rule and its exceptions

Colorado recognizes that the use of water for oil and gas production is a beneficial use of water, and thus must be permitted.[53] The Colorado Supreme Court has taken a broad view of what constitutes beneficial use in this regard: besides the typical uses of water for conventional drilling (such as using water for drilling mud) it includes the dewatering of coalbed methane ("CBM") deposits (because CBM production cannot be accomplished without dewatering), and the extraction of groundwater that occurs in the form of produced water.[54] While the latter two "uses" may seem counter-intuitive to an oil and gas practitioner, keep in mind that the proper focus is upon whether the oil and gas operation reduces water levels upon which decreed rights depend.

In the wake of *Vance v. Wolfe* (2009) especially, it became clear that oil and gas operators would generally be required to obtain water rights or water permits other than water rights for many of their operations.[55] For an operator who requires a long-term and dependable supply of water for its fracking operations, the best option may be to acquire an existing water right, and then obtain regulatory (and possibly water court) approval of the change in the water right to the industrial use of oil and gas production. This procedure permanently changes the water right. This can be an expensive and time-consuming process, especially within Colorado's water court system.[56]

Operators in Colorado need to pay close attention to the legal classification of the water they seek to use. As described above, surface water and tributary groundwater qualify as "waters of the state" of Colorado and are thus regulated according to the 1969 Water Rights Determination Act through the state's water court system and its division engineers.

If the water supply is groundwater within one of Colorado's designated groundwater basins, then it is designated groundwater. Obtaining water supply from a designated groundwater well will likely require executing an agreement with the permitted holder of such a well, and would further require approval from the Colorado Ground Water Commission for approval of the change (likely from an irrigation use) to the industrial use of oil and gas production.

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[53] Vance v. Wolfe, 205 P.3d 1165 (Colo. 2009).

[54] *Id.*

[55] In 2010, the Colorado State Engineer determined that produced water from most oil and gas operations in the state is nontributary, substantially reducing the scope of the decision in *Vance.* 2 Colo. Code Regs. § 402-17:17.5; Colo. Rev. Stat. § 37-90-137(7)(a).

[56] Colo. Rev. Stat. §§ 37-92-201 to -203.

If the water supply is nontributary groundwater, then the overlying landowner must either obtain a decree from the water court for the right to pump a defined amount of groundwater, or apply to the State Engineer for a well permit.[57] Assuming such a permitted well for nontributary groundwater is in place, an oil and gas operator can then contract with the well's owner to use the groundwater. Such an agreement is permissible, and is accomplished through the issuance of a well permit. This permit does not restrict types of use, but restricts the withdrawal of groundwater so that no more than 1% of the groundwater contained in the aquifer may be withdrawn annually.

There are, however, two exceptions to these permitting requirements. These may be useful for operators who have temporary water needs.

The first exception is a temporary change in an existing water right, known as the temporary approval of a substitute water supply plan.[58] This process is statutorily recognized as meeting a need for water users for whom the usual water court adjudication process is less justifiable, based on the temporary usage of the water. A substitute water supply plan must include, among other things, a proposed plan for replacing out-of-priority depletions.

The second exception is that of the interruptible water supply agreement, another creature of Colorado statute.[59] This provision bypasses the standard water court adjudication process.[60] It allows the holder of a water right to loan the right to another user, provided that the loan is not used more than three years within a ten-year period.[61] To obtain the necessary approval of such an agreement, both parties to the agreement must submit an application to the State Engineer. The application is subjected to the notice and comment requirements of the Colorado water court system, and objections and other comments to the application may determine whether the State Engineer denies the application, or approves it with certain conditions.[62]

b. Kansas

As surveyed above in Section II.A, Kansas places the jurisdiction over all of the water supplies of the state within one agency, KDWR, whose Chief Engineer regulates water usage pursuant to the doctrine of prior appropriation. Kansas's permitting regime is thus generally similar to that of Wyoming, New Mexico, and other "pure" prior appropriation states in the West that place the administration and adjudication of water resources within a state agency (rather than placing adjudication matters within a water court, as Colorado does).[63] Within this category, however, it must be noted (as always) that each state has its own distinct permitting requirements.

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[57] Bayou Land Co. v. Talley, 924 P.2d 136, 147–49 (Colo. 1996).

[58] Colo. Rev. Stat. § 37-92-308.

[59] *Id.* § 37-92-309(1).

[60] *Id.* § 37-92-309(3).

[61] *Id.* § 37-92-309(3)(c).

[62] *Id.* § 37-92-309(3).

[63] For a recent survey of the subject, see Eva N. Neufeld, John C. Peck & Adam C. Dees, "Water Allocation Law and the Oil and Gas Industry in Kansas: An Update to the 1981 Neufeld Article," *Journal of the Kansas Bar Ass'n* (Sept. 2012).

i. The basic permitting rule and its exceptions

The most important rule to follow in Kansas is this: an oil and gas producer must obtain a permit to use water for its operations. It is illegal to appropriate water or threaten to appropriate water in Kansas without a valid water right or other water use permit issued by the Chief Engineer of KDWR.[64] An oil and gas lessee does not have an implied right to use water found on the premises of the lease. Therefore, an oil and gas producer will need a state permit for the water required for its lease operations. Oil and gas operators who assume otherwise, perhaps because they originate from Texas, can place their operations at significant peril if they do not heed the permit requirement. Appropriating water or threatening to appropriate water without a permit is a Class C misdemeanor,[65] and every day a violation occurs after notice is given by the Chief Engineer, constitutes a separate offense.[66] Civil penalties include fines, which may not be sufficient to deter an unscrupulous oil and gas operator.[67] More importantly, the Chief Engineer has clear statutory authority to shut down unpermitted uses of water, including making reductions in permissible water use that would otherwise be allowed when a permit is eventually obtained. Thus, the opportunity cost of such an unscrupulous violation could greatly exceed the fines allowable as civil penalties.

There are four exceptions to this permitting rule, which vary in their applicability to oil and gas producers. The first exception is that of domestic use.[68] This exception is of no use for oil and gas producers in Kansas, because oil and gas production is not a domestic use.[69] Thus, an oil and gas producer who obtains a domestic right must first obtain DWR approval to change that right from domestic to industrial use, which, as set forth above, requires a permit.[70] The second exception applies to annual diversions and beneficial use of less than 15 acre-feet of surface water annually, impounded in any reservoir smaller than 15 acre-feet.[71] Because this exception is not limited to domestic use, and oil and gas production is a recognized beneficial use of water, it may be an attractive option for smaller producers, provided they can obtain the water from a willing seller. However, there are potential legal uncertainties surrounding the use of water from ponds that are part of a watershed district, not to mention dependability issues with surface water supplies in times of drought.

The third legal exception concerns salt water. The use of water whose composition exceeds 5,000 mg/l in chlorides does not require a permit.[72] Kansas has plentiful saline groundwater supplies, especially in the Dakota Aquifer, and Kansas law has a clear statutory and regulatory preference for the use of salt water in oil and gas operations. As the fracking industry increases its ability to employ salt water in fracking operations, this exception has become a more popular option, especially in the Niobrara Formation of northwest Kansas.

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[64] Kan. Stat. Ann. § 82a-728.

[65] *Id.* § 82a-728(b)(1).

[66] *Id.* § 82a-727(b)(2).

[67] *Id.* § 82a-737.

[68] *Id.* §§ 82a-705, -728.

[69] *Id.* § 82a-701(c).

[70] *Id.* § 82a-708b.

[71] *Id.* § 82a-728.

[72] *Id.*

The final exception is for water withdrawn and used under a contract pursuant to the Kansas State Water Plan Storage Act.[73] Water supplies under this exception generally relate to federal reservoirs. Because the use of water for oil and gas production is a recognized beneficial use (industrial use), and because most reservoirs in Kansas are limited to municipal and industrial uses, oil and gas operators could employ this exception.[74] (This is in contrast to states such as North Dakota, where federal reservoirs are generally limited to flood-control, recreation, and navigation purposes.) Contract water obtained under this exception offers the advantages of water-supply dependability and transactional efficiency: one contract could serve multiple well sites and leases. However, contract water is generally more expensive than obtaining water under the permits described in the next subsection.

ii. Water rights

As described in Section II.A above, water rights in Kansas are real property rights, appurtenant to the land where the water is used.[75] Where unappropriated water is available (an increasingly rare situation in Kansas), supplies can be obtained by application to KDWR.[76] More frequently, they are obtained by purchase, lease, or other conveyance. Because most Kansas water rights are irrigation rights, the oil and gas operator who obtains a water right will need to obtain KDWR approval to change the right from irrigation to industrial use.[77] Water rights can also be divided in Kansas, subject to the approval of the Chief Engineer.[78] For example, an irrigator who owns a water right of 400 acre-feet can lease or sell 100 acre-feet of that right to an oil and gas operator; the operator, in addition to obtaining the water, would also obtain the same priority of the pre-divided water right.[79] Before putting the divided water right to beneficial use for oil and gas operations, however, the operator will still need to obtain the requisite approval for the change from irrigation to industrial use, which engages the consumptive use limitations summarized and illustrated in Section II.A.

Water rights have important advantages for oil and gas producers. They are permanent and do not expire, as water permits do. Given the size of a typical irrigation water right in Kansas from which an oil and gas water right would be derived, such a right would provide plentiful water supplies. And senior rights enjoy the protections of priority during times of drought and groundwater depletion. However, water rights have not proven to be a good fit with most oil and gas operations in Kansas, for several reasons. First, as we have seen, obtaining a water right can be cumbersome, both transactionally and from a regulatory standpoint. New water rights applications and applications to change existing rights can take months and even years to complete, raising obvious timing issues for an operator (especially an assignee or farmee) who is facing the end of the primary term of an oil and gas lease. Finally, as summarized in the next

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[73] *Id.* § 82a-1313.

[74] Kan. Admin. Regs. § 5-5-1(qq).

[75] Kan. Stat. Ann. § 82a-701(g).

[76] *Id.* § 82a-711.

[77] *Id.* § 82a-708b.

[78] *Id.* § 82a-742.

[79] *Id.*

subsection, alternatives to water rights—temporary water permits—have generally served to meet the needs of most oil and gas producers in Kansas. Yet this may be changing, due to the longer-term and higher-volume needs for sustained fracking operations.

iii. Water permits that are not water rights

Largely (but not exclusively) in response to the needs of the oil and gas industry in Kansas, the legislature and KDWR have provided permitting alternatives to water rights in the form of water permits. Kansas recognizes four different types of water permits.

The first type is a temporary permit.[80] It entitles the permit holder to use 4 million gallons (12.28 acre-feet) of water, and lasts for a term not to exceed six months.[81] Due to the relatively small amount of water permitted—at least compared to an irrigation right—term permits are not subject to safe yield requirements, but a term permit cannot impair existing water rights. Temporary permits are limited to one application per project, one place of use, and one point of diversion, and they are non-transferable.[82] Although they do not qualify as water rights, they do receive a priority date and its attendant protections.[83] Temporary permits enjoy the advantage of a fast processing time, usually within a month or so, because they are usually processed through KDWR's field offices. However, their disadvantages have become apparent with the advent of fracking: they are limited to one use, short in duration (six months), and non-transferable, which means an assignee or farmee will not be able to use the temporary permit of the assignor/farmor.

The second type of water permit is the term permit, which is essentially a temporary permit enlarged in quantity and extended in duration.[84] Term permits can grant more than four million gallons of water as long as the quantity is deemed to be reasonable, and term permits are not subject to safe yield requirements (although they cannot impair existing users).[85] A term permit can last as long as five years (rather than the six-month limit for temporary permits).[86] There are two exceptions to this temporal limitation. First, if the applicant can show that water usage under the term permit does not exceed safe yield, that it will not impair existing rights, and that the applicant has good cause, the holder of a term permit can obtain an extension beyond five years.[87] Second, if the water to be used under a term permit contains more than 5,000 mg/l of chlorides, then the initial term can extend to as long as ten years, and may be extended further to twenty years.[88] Term permits allow more water usage and for a longer duration than temporary permits. But due to their larger size and commensurate potential to impair existing water rights, applications for term permits are processed at KDWR's central office,

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[80] *Id.* § 82a-727.

[81] Kan. Admin. Regs. §§ 5-9-3, -7; Kan. Stat. Ann. § 82a-728.

[82] Kan. Admin. Regs. §§ 5-9-4, -5, -8.

[83] *Id.* § 5-9-2.

[84] Kan. Stat. Ann. § 82a-708c.

[85] Kan. Admin. Regs. § 5-9-3.

[86] *Id.* § 5-9-1b(a).

[87] *Id.* § 5-9-1(c)–(d).

[88] *Id.* § 5-9-1b(b)(4).

and generally require up to six to eight months to process—a much longer period than that for temporary permits.

The third type of water permit is a basin term permit, a sub-type of the term permit. Basin term permits are limited to surface water supplies within a specific drainage basin. They allow the use of much larger quantities of water—as much as 100 acre-feet annually—and are generally intended for oil and gas drilling, as well as for construction projects.[89] Due to the scarcity of surface water supplies in western and south-central Kansas, these permits have proven to be of limited utility for most oil and gas producers.

The final type of water permit is the limited transfer permit, a new type enacted in 2012 and modeled on similar permits in Wyoming.[90] It contains the same quantitative limits as a temporary permit (four million gallons), but unlike a temporary permit, which stands alone, a limited transfer permit is carved out of the water supply of an existing water right, called the "base water right."[91] The duration of a limited transfer permit is limited to a single calendar year—longer than the six months' maximum for a temporary permit, but shorter than that for a term permit.[92] The chief advantage of a limited transfer permit is water availability: because the water for the permit derives from the base water right, it should present few obstacles concerning safe yield or the impairment of existing rights—provided that there is no increase in the consumptive use enabled by the permit.[93] Thus, an oil and gas operator seeking to obtain a limited transfer permit from the holder of a base irrigation right should factor in the increase in consumptive use from irrigation use to the industrial use of oil and gas production.

c. Oklahoma

i. The permitting rule

Oklahoma follows the prior appropriation doctrine for surface water and a modified rule of capture approach for groundwater, but permits to use either water supply are generally mandatory and issued by the OWRB. Both surface and groundwater permits are transferable in Oklahoma. For both surface and groundwater permits, similar application and approval procedures apply.[94]

a. Surface Water Supplies

Regarding surface water supplies, the OWRB issues no fewer than six different types of permits. The first is a regular permit, which authorizes the year-round use of surface water.[95] The second is a seasonal permit, which authorizes diversions of available surface water for specified time periods during the calendar year.[96] Both regular and seasonal permits are understood as conferring permanent water rights.

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[89] *Id.* § 5-1-1(M)(1).

[90] Kan. Stat. Ann. § 82a-743.

[91] *Id.* § 82a-743(a)–(b).

[92] *Id.* § 82a-743(a).

[93] *Id.* § 82a-743(c).

[94] Okla. Stat. tit. 82, §§ 105.9–.11 (for surface water); *id.* §§ 1020.7–.9 (for groundwater).

[95] *Id.* § 105.1(3).

[96] *Id.* § 105.1(4).

The other four types of permits are not permanent water rights; the OWRB can issue them if it finds that such issuance will not impair or interfere with domestic uses or existing rights, and it may even issue a permit when it finds that no unappropriated water is available for a regular permit.[97] The third type of surface water permit is a temporary permit, which authorizes water usage for a period up to three months.[98] The fourth type is a term permit, which lasts much longer, for a term of years.[99] The fifth type is a limited quantity stream permit, for quantities less than 15 acre-feet.[100]

The final type of permit for surface water use is exceptional compared to the other non-permanent permits: a provisional temporary permit, which lasts for a maximum of 90 days and is nonrenewable.[101] Alone among the other types of surface water permits in Oklahoma, a provisional temporary permit can be issued by the OWRB at its discretion, without the standard review process: no public hearing is required.[102] The director of the OWRB may grant a provisional temporary permit when denial will cause economic hardship to a user who otherwise has permission to use the land for diverting water, and the permit will not interfere with existing uses of water.[103]

b. Groundwater Supplies

The OWRB issues four types of groundwater permits. Regular permits are those that have been fully permitted according to Oklahoma's "equal proportionate share" approach. Under this approach, landowners are entitled to a share of the groundwater beneath their land, based on a "maximum annual yield" that is determined by the OWRB following a hydrologic survey; the yield assumes a twenty-year basin or subbasin life.[104] The second type of permit is a temporary permit, which authorizes the same uses as a regular permit, but applies to groundwater basins where the OWRB has not yet completed the requisite hydrological survey and maximum annual yield determination for regular permits; a temporary permit allows the landowner to pump two acre-feet per acre.[105] Temporary permits must be revalidated every year during their term, and if their revalidation is protested, the OWRB conducts a public hearing on the revalidation.[106] The third type of permit is a special permit, which allows its holder to use groundwater in quantities in excess of those allocated under either a regular or temporary permit.[107] They are valid for no more than six months, but may be renewed three times; successive special permits cannot be granted for the same purpose.[108]

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[97] *Id.* § 105.113(A).
[98] *Id.* § 105.1(5).
[99] *Id.* § 105.1(6).
[100] *Id.* § 105.13(C).
[101] *Id.* § 105.1(7).
[102] *Id.*
[103] Okla. Admin. Code § 785:20-7-1.
[104] Okla. Stat. tit. 82, § 1020.5.
[105] *Id.* § 1020.11(B).
[106] *Id.* § 1020.11(B)(3)–(4).
[107] *Id.* § 1020.11(C).
[108] *Id.*

The final groundwater permit is a provisional temporary permit, which is essentially similar to its surface water counterpart in bypassing the OWRB's public notice and hearing provisions and lasting for 90 days.[109] These permits are popular choices for oil and gas operators for drilling purposes.

Several other aspects of Oklahoma groundwater law are notable from the perspective of an oil and gas operator. Groundwater permits are explicitly not required for the taking, use, or disposal of salt water associated with oil and gas production.[110] Municipalities have the power to regulate or permit industrial wells within their corporate limits.[111] Finally, landowners are expressly authorized to unitize and communitize their lands for the purposes of groundwater production, provided such production does not exceed maximum annual yield.[112] This last provision shows how Oklahoma, like Texas, has used concepts originating in oil and gas law and applied them to water law.

d. Texas

Texas follows the prior appropriation doctrine for surface water and the rule of capture for groundwater.[113] However, its prior appropriation doctrine has an important statutory qualifier: the Texas Water Code establishes use preferences, which factor into the state's granting of appropriative water right permits.[114] In descending order, these uses are: (1) domestic and municipal uses; (2) agricultural and industrial uses; (3) mining and recovery of minerals; (4) hydroelectric power; (5) navigation; (6) recreation and pleasure; and (7) other beneficial uses.[115] Once appropriative rights are established, however, priority rules: "the first in time is the first in right."[116]

i. Surface water

Texas requires a permit for all non-domestic uses of "state water," which is surface water.[117] The TCEQ has jurisdiction over surface rights and grants water permits, and has a typical notice and review procedure and standards for evaluating new water rights applications.[118] The TCEQ grants five types of water permits to the state's surface waters. The first type of permit is a regular permit, which entitles its owner to all of the attributes described in the permit.[119] The second type is a seasonal permit, which is issued in the same manner as regular

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[109] *Id.* § 1020.10(A).

[110] *Id.* § 1020.2(B).

[111] *Id.* § 1020.21.

[112] *Id.* § 1020.20.

[113] *See* note 33 *supra* for the exceptional legal treatment of surface water supplies in parts of the Rio Grande Basin in Texas.

[114] Tex. Water Code Ann. § 11.024; State v. Hidalgo Cnty. Water Control & Improvement Dist. No. 18, 443 S.W.2d 728 (Tex. App.—Corpus Christi 1969).

[115] Tex. Water Code Ann. § 11.024. Oil and gas operations likely fall into the third category, mining, since the second category (agricultural and industrial uses) defines industrial use as "processes designed to convert materials of a lower order of value into forms having greater usability and commercial value, including the development of power by means other than hydroelectric." *Id.*

[116] *Id.* § 11.027.

[117] *Id.* §§ 11.081, .121.

[118] *Id.* §§ 11.128–.135.

[119] *Id.* § 11.135.

permits, but is limited to portions of the calendar year stated in the permit, and may contain conditions necessary to protect prior rights.[120] Both regular and seasonal permits confer a permanent right.

The other three types of surface water permits are impermanent. The third type is a temporary permit.[121] These may be valid for as long as three years, and can be issued if the proposed water use does not interfere with prior appropriations or vested rights.[122] Temporary permits fall under the TCEQ's requirements for notice and hearing, unless the applicant seeks 10 acre-feet of water or less for no more than one year.[123] The fourth type of surface water permit is a term permit. It is valid for a term of years, and allows for the use of water that will eventually be permitted under a regular permit; it applies while the applicant's unperfected water right (with the same general attributes) is going through the perfection period.[124] The fifth and final type of permit is an emergency permit, which is of little relevance to an oil and gas operator.[125]

In 2015, the Texas Legislature added a chapter to the state's water code providing for the permitting of water use drawn from the state's waters within the Gulf of Mexico, to facilitate the construction of desalination plants.[126] Obviously, the permitting of salt water supplies from the Gulf does not raise any of the availability or impairment issues that are generally the focus of the permitting process for other state water permits. Thus, this chapter provides for a streamlined permitting process for seawater.[127]

ii. Groundwater

Texas delegates the regulation and management of groundwater supplies, which are not "state water," to GCDs. These districts are statutorily required to require permits for wells, and may impose more restrictive permit conditions on new permits.[128] However, Texas courts have made it abundantly clear that the powers of a GCD have regulatory limits: where groundwater regulation goes too far by too severely restricting landowners' Texas-given right to pump the groundwater they own, such restrictions can amount to takings, requiring the GCD to pay just compensation.[129]

For oil and gas operators, though, the permitting requirement for groundwater supplies is largely overwhelmed by a statutory exemption—or not, depending upon the GCD in which the prospective use of water is located. Wells used "solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil and gas well" do not require a permit, provided that the permit holder is responsible for drilling and operating the well, *and* the well is

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[120] *Id.* § 11.137.

[121] *Id.* § 11.138.

[122] *Id.* § 11.138(a).

[123] *Id.*

[124] *Id.* § 11.1381(a).

[125] *Id.* § 11.139.

[126] *Id.* § 18.001 *et seq.* "State water" extends three miles beyond the shoreline. *Id.* § 18.001(a)(1).

[127] *Id.* § 18.003.

[128] *Id.* § 36.113.

[129] Bragg v. Edwards Aquifer Auth., 421 S.W.3d 118, 146 (Tex. App.—San Antonio 2013, pet. denied).

located on the same lease or field associated with the drilling rig.[130] Despite the language of this mandatory statutory exemption from the permitting requirement, which would appear to include fracking, many GCDs have not construed it to apply to fracking operations, and have required permits. Whether the statutory exemption applies to fracking is a matter of considerable debate and inconsistent application in Texas: nearly 40% of GCDs require permits for fracking operations, while the remainder treat fracking as falling within the exemption.[131] Even if an oil and gas operator is operating within a GCD that applies the exemption, the operator must still take care to follow the other rules of the GCD, such as well spacing and pumping rates and volumes.[132]

C. State Regulation and Permitting of Produced and Recycled Water

The laws, property rights rules, and regulations related to the permitting of produced and recycled water for subsequent use raise a myriad of legal issues. In approaching these issues, it is useful to keep several things in mind. First, the legal and regulatory regimes for produced water have traditionally assumed that such water was a problem, not a resource. Most laws and regulations concerning produced water deal with how to dispose of it, through injection, evaporation, or treatment and discharge into surface waters, rather than how to obtain ownership rights and regulatory permission for reuse. As a consequence, the rules for reuse of produced water have, like other water usage-related aspects of the oil and gas industry, been treated exceptionally under state water codes. Second, as oil and gas operators and commercial water operators increase the amount and proportion of produced water that they subsequently reuse for fracking operations, such reuse involves the jurisdiction of and regulation by state water agencies, agencies that are not as well-acquainted with the water needs of the oil and gas industry as they are with agricultural and municipal uses. Regulators, oil and gas operators, and courts can struggle with what constitutes beneficial use of water in a fracking operation. Third, as summarized in Section I above, the technology of produced water reuse is significantly ahead of the law, and the gap between what the oil and gas industry can achieve, and what state water agencies understand and regulate, is worrisomely wide, creating investment risks. Finally, there is considerable diversity, disagreement, and confusion regarding the ownership rights to produced water.

This concluding section first summarizes the main regulatory requirements for the reuse of produced water in Colorado, New Mexico, and Texas—states that are sufficiently arid to justify the additional costs of recycling produced water. Major oil and gas producing states that enjoy relatively plentiful water supplies, such as North Dakota, have not developed laws and regulations for the reuse of produced water. (Because these requirements are still in their infancy, the practitioner should be careful to stay current as they evolve.) Next, it surveys several of the most important ownership issues regarding produced water and the rights to its subsequent reuse.

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[130] Tex. Water Code Ann. § 36.117(b).

[131] *See* Tiffany Dowell Lashmet & Amber Miller, "Texas Exempt Wells: Where Does Fracking Fit?" 55 *Nat. Resources J.* 239, 254 (2015).

[132] Tex. Water Code Ann. § 36.116(a)(1)–(2).

1. Regulation of Produced Water for Reuse: A Western Survey

What follows is a survey of state laws and regulations regarding the reuse of produced water in Colorado, New Mexico, and Texas.[133] It does not include those laws and regulations related to the disposal of produced water, whether by re-injection by Class II injection wells for enhanced recovery or disposal, or by discharge into surface water bodies.

a. Colorado

Colorado regulates and permits the reuse of produced water in a number of ways through multiple agencies: the Colorado Oil and Gas Conservation Commission ("COGCC"), the Colorado Department of Public Health and Environment ("CDPHE"), and the Colorado Division of Water Resources ("CDWR").

COGCC regulations enable the beneficial use of produced water through the permitting of pits for its storage, recycling, reuse, and treatment; they may be permitted for as long as three years.[134] Oil and gas operators may combine produced water from multiple wells into one pit.[135] However, an important exception exists: a permit is not required where the reuse of produced water is limited to moving drilling fluids from one oil and gas location to another such location.[136] The COGCC also provides for the permitting of centralized facilities for the management of produced water; these may be operated for a period longer than three years.[137]

Oil and gas operators and operators of commercial waste impoundment facilities may also obtain regulatory approval to put produced water to beneficial use for uses other than oil and gas production. Permitting for this is done through the CDPHE's Hazardous Materials and Waste Management Division. The applicant must first obtain a determination of beneficial use from the division. To obtain such a determination, the applicant must establish that the beneficial use meets performance and storage standards and is not disposal in the guise of a true beneficial use.[138]

Finally, CDWR regulates and permits water use for oil and gas operations, but produced water is defined in regulations as nontributary.[139] Because of that definition, a well permit is not required if the nontributary groundwater that is removed from the ground during oil and gas operations will be used only by oil and gas operators within the same geologic basin. The scope of water uses within this exception includes commercial disposal, road spreading, dust-control, and other uses.[140]

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[133] This subsection partially relies on a useful recent Foundation paper, Keith Burron & Gage Hart Zobell, "How Industry and Regulators Are Responding to Challenges and Opportunities in Management, Reuse, and Beneficial Use of Produced Water," 63 *Rocky Mt. Min. L. Inst.* 12-1 (2017).

[134] 2 Colo. Code Regs. §§ 404-1:903, -1:904.

[135] *Id.* § 404-1:902(e).

[136] *Id.* § 404-1:903(a)(4).

[137] *Id.* § 404-1:100; *see* Burron & Zobell, note 133 *supra*, at 12-8.

[138] 6 Colo. Code Regs. § 1007-2:1-8.6; *see* Burron & Zobell, note 133 *supra*, at 12-8.

[139] 2 Colo. Code Regs. § 402-17:17.5. This determination was made in 2010 after the enactment of Colo. Rev. Stat. § 37-90-137(7)(c). *See also* the text accompanying notes 53–55 *supra.*

[140] Colo. Rev. Stat. § 37-90-137(7)(a).

b. New Mexico

Like Colorado, New Mexico has overlapping jurisdiction over the use of produced water for oil and gas operations. The Oil Conservation Division ("OCD") of the New Mexico Energy, Minerals, and Natural Resources Department and the New Mexico Environment Department ("NMED") have jurisdiction over disposal wells and discharge permits for produced water. Permitting and regulation of the state's water resources falls under the jurisdiction of the New Mexico Office of the State Engineer, according to the prior appropriation doctrine.[141]

Up until 2019, the state of the law for the reuse of produced water in New Mexico was unclear. On one hand, administrative regulations governing the OCD's permitting had been in place since 2008, and appeared to condone the beneficial use of recycled or treated water.[142] On the other hand, the Office of the State Engineer had not developed a water right permitting process specifically for putting produced water to beneficial use. As a result, it seemed that any beneficial use for produced water that had been recycled might fall under the regular jurisdiction of the State Engineer as groundwater.[143]

In 2019, the New Mexico legislature passed the "Produced Water Act," which attempts to resolve these ambiguities.[144] The oil and gas industry promoted this legislation, an effort to clarify regulatory jurisdiction over produced water, and to clarify who owns, controls, and is responsible for produced water—a potentially troublesome issue between oil and gas lessees/operators and landowners.

The Produced Water Act grants jurisdiction over produced water to state agencies according to their respective regulatory bailiwicks under state and federal law. Roughly stated, OCD has jurisdiction over the use of produced water in oil and gas operations, while NMED has jurisdiction over water quality regulation outside of those operations. OCD has jurisdiction over produced water pursuant to the New Mexico Oil and Gas Act, including the authority to make rules and orders for the disposition, handling, transport, storage, recycling, and disposal of produced water, both for oil and gas exploration and for production purposes, and for disposal by (Class II) injection wells pursuant to the federal Safe Drinking Water Act.[145] The New Mexico Water Quality Control Commission ("NMWQC"), composed principally of heads of the state's natural resources agencies, but administratively attached to NMED, has jurisdiction over produced water as provided in the New Mexico Water Quality Act.[146] The NMWQC is the water pollution control agency for purposes of the federal Clean Water Act, as well as for the wellhead protection and sole source aquifer programs of the federal Safe Drinking Water Act.[147] For uses regulated by the NMWQC pursuant to the New Mexico Water Quality Act—uses other than oil and gas exploration and

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[141] N.M. Stat. Ann. § 72-2-1.

[142] N.M. Admin. Code § 19.15.34.

[143] Burron & Zobell, note 133 *supra*, at 12-12.

[144] New Mexico Laws 2019, ch. 197. This discussion of New Mexico law relies upon the expertise of Mr. Bill Brancard, General Counsel of the New Mexico Energy, Minerals and Natural Resources Department.

[145] *Id.* §§ 3.A, 6.B.15.

[146] *Id.* § 3.B; N.M. Stat. Ann. § 74-6-3(F).

[147] N.M. Stat. Ann. §§ 74-6-1 *et seq.*

production—a permit is required from NMED before using produced water, "recycled or treated water or treated product or any byproduct of the produced water."[148] However, the New Mexico Water Quality Act maintains existing statutory language stating that the NMWQC "shall assign responsibility for administering its regulations to constituent agencies" as needed, to ensure adequate regulatory coverage and to prevent regulatory duplication; these "constituent agencies" include NMED and the Oil Conservation Commission.[149] Conversely, the Oil Conservation Commission shall adopt regulations to be administered by NMED for the "discharge, handling, transport, storage, recycling or treatment for the disposition of treated produced water" for activities that are unrelated to oil and gas production and refinement, such as roadway ice and dust control.[150] The Oil Conservation Commission may also adopt regulations, also to be administered by NMED, for surface water discharges.[151]

The Produced Water Act is also significant for the regulatory and property jurisdiction it excludes—specifically, from New Mexico's water rights regime. No permit from the State Engineer is required for the disposition of produced water, recycled water, or treated water; the disposition of any such water, "including disposition by use," does not qualify as an appropriation of water or a waste of water under the New Mexico water code, and "no water right shall be established by the disposition of produced water."[152]

Next, the Produced Water Act sets three default provisions for the ownership and control of, as well as the responsibility for, produced water—provisions that oil and gas operators and other parties in the produced water business can modify by contract.[153] First, all produced water from an oil and gas well is "the responsibility of and under the control of" the well's working interest owners and operators, who "shall have a possessory interest" in the produced water; this possessory interest includes the right to "use, handle, dispose of, transfer, sell, convey, transport, recycle, reuse or treat" the produced water "and to obtain proceeds" for such uses.[154] The Act imposes the reasonably prudent operator standard upon the operator of the well from which the produced water derives.[155] The second default provision applies to the transfer (by sale or other conveyance) of produced water to other entities within the produced water business: upon transfer, the transferee obtains the same control of, possessory interest in, and responsibility and liability for the produced water as the transferor had previous to the transfer.[156] The third default provision applies these same rules to operators

[148] New Mexico Laws 2019, ch. 197, § 4.D.

[149] *Id.* §§ 10.K.1, 10.K.4 (amending N.M. Stat. Ann. § 74-6-2).

[150] *Id.* § 11.P (amending N.M. Stat. Ann. § 74-6-4).

[151] *Id.* § 11.Q (amending N.M. Stat. Ann. § 74-6-4).

[152] *Id.* § 4.C.

[153] *Id.* §§ 4.A, 4.B. These provisions apply to an oil and gas operator (both as transferor and transferee), transporter, pipeline, midstream company, plant, processing facility, refinery, "or entity that provides recycling or treatment services for produced water." *Id.* §§ 4.A.2, 4.A.3. These provisions "shall not affect liability in an action brought by other persons for damages, including damages for personal injury, death or property damage, arising from exposure to produced water, recycled or treated water or treated product or byproduct." *Id.* § 4.B.

[154] *Id.* § 4.A.1.

[155] *Id.*

[156] *Id.* § 4.A.2.

and transferees who take possession of produced water for the purpose of recycling or treating the water, and makes clear that such transferees can also transfer it further.[157] To repeat: these are default provisions, and may be altered by contract.

By contrast, Section 5 of the Produced Water Act forbids, as void against public policy, three contractual provisions regarding produced water. The first forbidden provision is one that charges a fee for the movement or transport of produced water, treated water, or recycled water on surface lands owned by the state—provided that the agreement does not provide for transportation services.[158] (Thus, by negative implication, a contract for the transportation of produced water across state lands would not be forbidden, provided it complies with regulatory and permitting requirements.) The second prohibition voids any contractual provision that requires fresh water to be purchased for oil and gas operations when produced water, treated water, or recycled water can be used and the operator elects to use that non-fresh water in its operations.[159] The final prohibition voids any water-purchase contract that precludes an operator from purchasing or using produced water, treated water, or recycled water in the operator's oil and gas operations when such water is available for the operations.[160] These latter two prohibitions are consistent with a general policy preference within western water law—that non-fresh water should be employed whenever possible in oil and gas operations.

Aside from the recently enacted Produced Water Act, the OCD has longer-standing rules on various aspects of produced water handling, disposal and recycling, adopted pursuant to the New Mexico Oil and Gas Act. Of these rules, the one that is of most interest is Rule 19.15.34 of the New Mexico Administrative Code, which covers the registration and permitting of recycling facilities and produced water containment systems. The regulation seeks to streamline the approval of such facilities and systems (as opposed to other types of impoundments) to encourage the recycling of produced water within the oil and gas industry.[161]

To that end, the regulation sets up a tripartite regulatory structure. The first category concerns produced water used for drilling and production by oil and gas operators, who are generally exempted from the permitting requirements for produced water. No permit or registration is required for the disposition by use of produced water for "drilling, completion, producing, secondary recovery, pressure maintenance or plugging of oil and gas wells."[162] Furthermore, produced water recycling facilities that are part of a permitted operation for the drilling, completing, producing, or plugging of oil and gas wells do not require a permit.[163] (Any other disposition by use does require prior approval by OCD.[164])

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[157] *Id.* § 4.A.3.

[158] *Id.* § 5.A.

[159] *Id.* § 5.B.

[160] *Id.* § 5.C.

[161] Personal communication with Mr. Bill Brancard, note 144 *supra*, June 3, 2019 (on file with author).

[162] N.M. Admin. Code § 19.15.34.8(A)(1).

[163] *Id.* § 19.15.34.9(A).

[164] *Id.* § 19.15.34.8(A)(2).

The second category consists of recycling facilities that do not require a permit but must be registered.[165] Most of these recycling facilities are part of other oil and gas production-related activities that have already obtained the necessary permits or registrations for that activity: a permitted surface waste management facility; a permitted operation for the secondary recovery of oil and gas, enhanced oil recovery of oil and gas, or pressure maintenance projects; a permitted salt water disposal well; pits or below-grade tanks that have been registered; and registered recycling containment operations.[166] This second category also includes two recycling facilities connected to oil and gas activities that have not already been permitted or registered: those that are used with a closed loop system "that only delivers fluid for drilling and completion purposes," and those that are used with dedicated above ground tanks, which must be inspected weekly when holding fluids and whose inspections must be recorded in logs made available to OCD.[167]

The final category consists of all other recycling facilities—those that are not exempted from permitting and registration under subsection (A), or those that require registration pursuant to subsection (B) of the regulation. Facilities in this third category require a permit.[168] The most common type of recycling facility that would require a permit is probably a stand-alone facility, one that is not in addition to the oil and gas operations defined in subsections (A) and (B) of the regulation, such as a recycled-water facility that sells the recycled water to such operations.

Regardless of these permitting and registration categories, the rule applies other rules across the board. Notably, recycling facilities may be located on-site or off-site of a well drilling location, and may serve multiple wells.[169] However, they must not be used for the disposal of produced water.[170] All produced water for recycling and disposition by use "shall be handled and stored in manner that will afford reasonable protection against contamination of fresh water." This requirement is a regulatory articulation of the reasonable operator standard set forth in the Produced Water Act.[171] The operator of a recycling facility must also keep accurate records. Records quantifying the volume of water received for recycling, the amount of fresh water received separately, and the total volume of water leaving the facility for disposition by use must be reported monthly to OCD.[172] Records identifying the sources and disposition of all recycled water shall be made available for review by OCD upon request.[173] The operator of a recycling facility must remove all fluids within 60 days from the date the operator ceases operations; an extension is available from OCD, but it must not exceed two months.[174]

The enforcement provisions of the rule are set forth in its subsection 21. Violations that threaten contamination of fresh water, public health, or the

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[165] *Id.* § 19.15.34.9(B).

[166] *Id.* § 19.15.34.9(B)(1)–(4), (7).

[167] *Id.* § 19.15.34.9(B)(5)–(6).

[168] *Id.* § 19.15.34.9(C).

[169] *Id.* § 19.15.34.9(D).

[170] *Id.* § 19.15.34.9(G).

[171] *Id.* § 19.15.34.8(A)(4); see text accompanying note 155 *supra*.

[172] N.M. Admin. Code § 19.15.34.8(E).

[173] *Id.* § 19.15.34.8(F).

[174] *Id.* § 19.15.34.8(H).

environment shall require the immediate cessation of all recycling and containment operations, and may require the removal of all fluids by a date certain.[175] After notice of such a violation is issued, the operator may not obtain any permit—any permit—from OCD until the operator obtains an agreed compliance order, performs appropriate corrective action, or is granted a stay.[176] Other violations are subject to a 60-day correction period, unless OCD enters an agreed compliance order.[177] Stays, applications for review of notice of violation, and administrative review are all available for violations.[178]

The remainder of 19.15.34 NMAC consists of other regulatory requirements that are not summarized here, such as those concerning recycling containments, siting, design and construction specifications, operations, closure and site reclamation, financial assurance, and transportation of produced water and fluids.[179]

c. Texas

As with Colorado and New Mexico, addressing the issue of the reuse of produced water in Texas requires an understanding of the jurisdictional domains of the relevant state agencies. As everyone knows, the Texas Railroad Commission ("RRC") has jurisdiction over oil and gas development. Next, recall that Texas places all of its "state water" (surface water in a watercourse, as well as Gulf of Mexico water within three miles of the Texas shore) under the jurisdiction of the TCEQ, pursuant to the prior appropriation doctrine. Finally, Texas groundwater is the property of the overlying landowner, subject to the rule of capture and to permitting requirements by GCDs.

The RRC has led the way in advancing regulations for the reuse and recycling of produced water; these were significantly amended in 2013. The regulation essentially consists of three parts. First, it sets forth the general rule that the recycling of "oil and gas wastes" (a term whose regulatory definition includes produced water) requires a permit from the RRC.[180] However, the next regulatory subsection then lists the three categories of reuse where no permit is required. The first category includes the recycling of treated fluid for use in subsequent fracking operations or other well usage.[181] In the second category, "treated fluid," a defined term that appears to include produced water,[182] may also be reused "in any other manner"—apparently for uses other than oil and gas production—and "other than discharge to waters of the state," without a permit, provided that such reuse occurs pursuant to a permit issued by another state or federal agency.[183] Finally, treatment of fluid that results in distilled water does not require a permit for the use of the distilled water in any manner, "other than discharge to waters of the state."[184] In

[175] *Id.* § 19.15.34.21(B).

[176] *Id.* § 19.15.34.21(F).

[177] *Id.* § 19.15.34.21(C).

[178] *Id.* § 19.15.34.21(C)–(E).

[179] *Id.* §§ 19.15.34.10–.20.

[180] 16 Tex. Admin. Code § 3.8(d)(7)(A).

[181] *Id.* § 3.8(d)(7)(B)(i).

[182] *Id.* § 3.8(a)(44) (defining "treated fluid" as "fluid that has been treated using water treatment technologies to remove impurities such that the treated fluid can be reused or recycled").

[183] *Id.* § 3.8(d)(7)(B)(ii).

[184] *Id.* § 3.8(d)(7)(B)(iii).

effect, these exceptions permit the "non-commercial fluid recycling" of produced water—recycling done by an oil and gas operator, as opposed to a commercial recycler—without a permit; operators may perform that recycling on their own properties, and may transport fluid wastes for recycling on other leases.[185]

The final part of this regulation concerns activities that require an RRC permit for the reuse of produced water. Such permitting for the reuse of "treated fluid" will be evaluated on a case-by-case basis, taking into account the source, volume, chemical makeup, and proposed reuse of the treated fluids. Fluids that meet the requirements of a permit constitute a "recyclable product."[186] Commercial recyclers—as opposed to "non-commercial fluid recycling"—require a permit as well.[187]

A review of the New Mexico and Texas laws and regulations concerning the reuse and recycling of produced water reveals substantial similarities—hardly surprising, given that the Permian Basin straddles both states. Both states generally exempt most oil and gas operators from permitting requirements for the subsequent reuse of produced water in oil and gas operations. Both states also exempt oil and gas operations that include a recycled water facility from permitting requirements. Indeed, the only recycling facilities that do require permitting under both Texas and New Mexico law are those that are distinct from oil and gas operations—facilities whose principal business purpose is recycling, and not oil and gas production.

2. Ownership Issues Related to Produced Water and Underground Storage

Across the different jurisdictions of oil and gas producing states, two of the most interesting legal problems posed by the fracking revolution are the ownership of produced water, and the ownership of the pore space in which that water occurs (and/or to where it is returned for disposal and storage purposes). Recent cases in Texas have brought these property problems to the fore. Practitioners need to be aware of these issues, because the conclusions reached by the courts may contradict received assumptions regarding the traditional dominance of the mineral estate over the surface estate.

In states that follow the prior appropriation doctrine, it has always been true that use of the implied easement of a mineral owner to access and use water supplies on the surface owner's property has not been permissible—no matter how many times such a right has been stated in a Producers 88 lease or its ilk—without state approval of that use in the form of a distinct water permit or water right.

For states that follow the rule of capture for groundwater (explicitly in Texas, and often effectively in Oklahoma), the respective rights of the mineral owner (the oil and gas producer) and the landowner are evolving in interesting ways. Recall that in Texas, the estate of the overlying landowner includes all of the groundwater beneath their land.[188] In 2016, the Texas Supreme Court maintained its allegiance to oil and gas principles in water law, by holding that interests in groundwater in Texas can be severed from the land as a separate estate, just as the mineral estate

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[185] *Id.* § 3.8(a)(41).

[186] *Id.* § 3.8(d)(7)(C)(i).

[187] *Id.* § 3.8(d)(7)(C)(ii).

[188] Edwards Aquifer Auth. v. Day, 369 S.W.3d 814 (Tex. 2012).

can be severed, and by applying the protections of the accommodation doctrine to owners of such a groundwater estate.[189] In 2017, the Texas Supreme Court further elaborated upon the scope of the surface owner's estate, holding that it also includes the geological substrate in which oil and gas hydrocarbons are located.[190] As the court put it, "[w]hile the mineral estate is dominant . . . the rights of a surface owner are in many ways more extensive than those of the mineral lessee."[191]

The decisions in *Edwards*, *Coyote Ranch*, and *Lightning* all derive from Texas, a rule of capture state for groundwater, but the reasoning of these decisions may well gain traction in other jurisdictions—including prior appropriation doctrine jurisdictions. For example, in Colorado, produced water has been administratively determined to be nontributary, and thus part of the surface owner's estate.[192] The rights of such a Colorado surface owner against a mineral lessee may well become quite similar to his or her counterpart in Texas.

New Mexico's Produced Water Act raises similar issues. Sections 4 and 5 of that act make clear the legislature's intent to distinguish typical New Mexico water rights—rights to the use of fresh water, granted and regulated by the State Engineer, and closely governed by prohibitions on waste—from property rights in produced water itself, rights which by default rule originate with the oil and gas operator, whose operations produce the water, and who may in turn transfer that water to others. That distinction is salutary, and intended to resolve competing claims to (and liability for) produced water between oil and gas operators on one side, and landowners and surface estate owners on the other. However, the act appears to make a major change in New Mexico property law: at least by default, it makes produced water part of the mineral estate, an estate that has traditionally been limited to underground hydrocarbons. Does that legislative change take real property—water supplies contained in shale rock that would remain part of that rock substrate, and thus presumably part of the surface estate (at least according to *Lightning*), but for the fracking operations performed by the operator—away from the surface estate holder and give it to the mineral estate holder? Time will tell whether the act's distinctions between water supplies and its apparent change in the respective property rights of surface and mineral owners survive legal scrutiny.

Finally, if the surface owner owns what may eventually become recognized in some jurisdictions as a "groundwater estate," as seems easily conceivable in Texas, then there are at least two important considerations for oil and gas producers. First, the use of produced water should require an agreement between the oil and gas operator and the landowner for the use of what is (or might be construed) as the latter's groundwater. Second, because the landowner may also own (and in Texas, does conclusively own) the geological substrate and pore space within which recycled water can be re-injected and stored for future use, that substrate and its constituent oil and gas pore space must be separately obtained by

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[189] Coyote Lake Ranch, LLC v. City of Lubbock, 498 S.W.3d 53 (Tex. 2016). For a recent decision reaffirming and defending the rule of capture for Texas groundwater, see *Sipriano v. Great Spring Waters of America*, 1 S.W.3d 75 (Tex. 1999).

[190] Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39 (Tex. 2017).

[191] *Id.* at 48.

[192] *See* text accompanying notes 18, 55, and 139 *supra*.

the lessee. In the aftermath of *Lightning*, and in anticipation of its likely progeny, do not take such a right as implied.

Environmental Due Diligence in Mining Transactions

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Synopsis

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I. Introduction

Everyone has, or at least has heard, the horror stories of a company forced to spend hundreds of millions of dollars to address legacy environmental issues that it acquired in a recent, or not so recent, transaction. In some circumstances the issues giving rise to the liability were truly unknowable at the time of the transaction, but in the vast majority of these situations the environmental issues giving rise to the liability were discoverable, had appropriate due diligence been conducted. These horror stories are particularly prescient in the mining industry, where environmental issues associated with historic mining operations are common. Identifying and understanding the potential environmental liabilities at issue in a transaction are key to avoiding unpleasant surprises down the road.

Environmental due diligence in mining transactions should be effectively designed to identify, understand, and evaluate the risk presented by the answers to three major questions:

- Does the target of the transaction have the necessary permits, or is it likely to obtain the necessary permits to conduct the operations that are being conducted or are desired to be conducted?
- Does the target of the transaction have issues with non-compliance with environmental laws, regulations, and the terms of its environmental permits that could result in material liability?
- Does the target of the transaction have exposure to liability for environmental contamination?

In her complementary paper, Dawn Meidinger covers environmental due diligence in mining transactions as it relates to resource management and protection laws, including state and federal mine permitting and reclamation laws, wildlife protection laws, historic preservation laws, and the regulation of discharges of dredged or fill material, so those topics are not specifically covered in detail here.[2] This paper focuses on environmental due diligence as it relates to environmental laws addressing pollution, wastes, and toxic and hazardous substances.

This paper provides a practical overview of the environmental due diligence process regarding potential liabilities for compliance with these environmental laws and liabilities for environmental contamination in the context of mining transactions. It discusses the purpose, structure, and limitation of environmental due diligence, provides an overview of the major environmental statutory schemes that govern the environmental compliance issues and liabilities most common in the mining industry, and explains the practical role that the results of environmental due diligence play in informing the transaction and the parties' post-closing conduct. This paper is not an exhaustive treatise on environmental due diligence—it does not detail and catalog every potential environmental compliance issue or liability that could arise and impact a transaction. The potential legal and factual scenarios that could arise are too numerous to make such a treatise practical here.

Environmental due diligence, like all aspects of due diligence, is designed to provide information necessary to inform the clients' decision regarding the proposed transaction. The tricky part of environmental due diligence is that the liabilities for environmental contamination or non-compliance with environmental laws are not always obvious and the associated liabilities can be large. For example, contaminated soils and groundwater may exist where the surface appears pristine, potentially leading to millions of dollars in cleanup liability. Accordingly, appropriate environmental due diligence should be designed to identify potential liabilities and instances of non-compliance so that the parties to the contract can make informed decisions regarding the transaction. Specifically, environmental due diligence will inform the value proposition of the transaction—material environmental liabilities or potential liabilities should be accounted for in the price a buyer is willing to pay; inform the deal structure and documentation to ensure that liabilities are appropriately allocated among the parties, bearing in mind that contractual allocations or indemnities do not absolve a party from statutory liability;[3] and inform the buyer's post-closing plans for the property.

II. Scoping Environmental Due Diligence

If asked, most environmental practitioners would prefer that a "leave no stone unturned" approach to environmental due diligence be undertaken on each and every transaction. This sentiment is justified by the nature of potential environmental liabilities, where latent issues, not readily apparent, can lead to significant liability, and it is reinforced by practitioners' desire to have all of the facts before advising a client on whether and how to proceed in a transaction.

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[2] *See* Dawn Meidinger & Chris Evanoff, "Mining Permitting and Regulatory Compliance," *Due Diligence in Oil & Gas and Mining Transactions* 18-1 (Rocky Mt. Min. L. Fdn. 2018).

[3] *See* 42 U.S.C. § 9607(e).

However, the reality is that a leave-no-stone-unturned approach to environmental due diligence is rarely feasible or desired by the client. Accordingly, establishing and documenting a defined scope for the environmental due diligence is an important first step that ensures a common understanding of the task at hand.

Scoping environmental due diligence is inherently a balancing exercise: during the decision-making process, information is needed regarding the environmental issues and risks on one side of the scale, and the practical constraints upon unlimited environmental due diligence on the other. An early, thorough evaluation of the nature of the transaction and the assets involved is key to appropriately scoping the environmental due diligence, because both of these factors will influence potential liabilities and risks present in the proposed transaction. Once the potential risks are identified, a detailed discussion can be had with the client to scope due diligence around these risks and the client's cost, timing, and other considerations.

A. Nature of the Transaction

The structure of the proposed transaction has a significant impact on the appropriate scope of due diligence. The environmental risk factors of an asset transaction, where only specified assets such as a single operational mine, exploration project, or other defined set of assets is being transferred from buyer to seller, are substantially different from the environmental risk factors of an entity transaction where the buyer acquires an entire company that owns the target assets. With an asset transaction, potential liability is generally limited to liability regarding the assets being acquired.[4] The scope of environmental due diligence can, accordingly, be limited to the environmental risks presented by the assets specifically involved in the transaction.

Entity transactions provide an entirely different scenario. In entity transactions the buyer is acquiring an entity, be it a corporation, limited liability company, or other type of business entity, owning certain target assets. That entity may own other non-target assets, may have owned or operated other facilities in the past, and may have entered into contracts or other arrangements, all of which have the potential to create environmental liabilities unrelated to the target assets that are driving the deal. These issues can be significant—in acquiring a business entity the buyer acquires all of the entity's assets and liabilities, regardless of their relationship to the assets driving the deal.[5] The scope of environmental due diligence for such a deal must include investigation of the full panoply of potential environmental liabilities arising from all of the entity's present and historical operations and dealings.

The structure of the transaction also materially impacts the need to transfer permits, provide permitting agencies notice, or obtain consent from the permitting authority. Generally, asset transactions present a more straightforward analysis: where an asset is transferred, the permits necessary to operate that asset must be

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[4] Byron F. Egan, *Asset Acquisitions: Assuming and Avoiding Liabilities*, 116:3 PENN ST. L. REV 913 (2012).

[5] Howard L. Schecter, *Selected Risk Issues in Merger and Acquisition Transactions*, 51 U. MIAMI L. REV. 719 (1997).

transferred, or reapplied for if a permit is non-transferrable.[6] Entity transactions sometimes require a more nuanced analysis of whether the changes in control of the entity holding permits triggers any notification of consent requirements.

It is important to keep these considerations in mind as the deal evolves. As deal structure often changes over the course of negotiations from an asset transaction to an entity transaction, or vice-versa, it is important to revisit the scope of the environmental due diligence being conducted.

B. Nature of the Asset(s)

The assets involved in a proposed transaction also significantly impact the scope of environmental due diligence necessary. Where the transaction involves only a greenfield exploration project, where no mining or other industrial or commercial activity has previously occurred, due diligence can be narrowly focused. In these situations, it is important to confirm that the site truly is a greenfield site and no historic mining, industrial, or other activity that could have resulted in environmental contamination has previously occurred. Once this is confirmed, environmental due diligence can focus on the current exploration activity and operations. However, where the transaction involves assets that have operated for many years, were the site of previous historical operations, or present a risk of contamination from operations on adjoining properties, a broader investigation of the potential for environmental liabilities is warranted.

Special care should be taken with proposed transactions where only a non-possessory interest such as a royalty or security interest[7] is being acquired. These present unique circumstances where the potential for liability may depend on the level of control the transaction documents allow, and the interest holder actually exerts, over operations.[8]

C. Limiting Factors

The primary drivers in establishing the scope of environmental due diligence often have less to do with the potential environmental legal risk arising from a proposed transaction, and more to do with non-legal client considerations, such as cost, timing, and confidentiality.

1. Cost

The primary client consideration that drives the scope of due diligence is often cost. It is important to obtain and understand the client's budget for due diligence early in the scoping process. While controlling costs is important, it is also important to discuss the risks of limiting certain aspects of environmental due

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[6] *See, e.g.*, 27 C.F.R. § 555.53 (explosives licenses issued by the Bureau of Alcohol, Tobacco, Firearms and Explosives are non-transferable).

[7] Care should be taken in structuring these types of interests to ensure that they do not give rise to arguments that the holder of the interest had sufficient control over the operations to give rise to liability for environmental contamination or non-compliance with environmental laws. *See* 42 U.S.C. § 9601(20)(E) (excluding lenders holding a security interest from the definition of owner or operator under CERCLA only if the lender does not participate in the management of the facility in question); *see also* Nu-West Mining Inc. v. United States, 768 F. Supp. 2d 1082 (D. Idaho 2011) (holding the U.S. Government liable under CERCLA because of the level of control the United States exerted over operations at the facility).

[8] *Nu-West Mining*, 768 F. Supp. 2d 1082.

diligence—each limitation bears some correlative increase in the risk that a significant environmental issue or liability goes undiscovered in the diligence process. In the end, the client must make an informed decision on the appropriate scope of environmental due diligence.

A common area where cost considerations trim the scope of due diligence is in reviewing seller-provided documents and information. Under ideal circumstances, a member of the diligence team with specialized environmental knowledge would review each and every document provided by the seller to identify potential environmental issues and liabilities. For many mining transactions this would involve review of thousands, if not hundreds of thousands of documents. The cost of such a review can quickly become untenable and limiting the review of seller provided documents is required.

Cost considerations also often drive the scope of on-site due diligence. By virtue of the assets involved, mining transactions often involve large swaths of property and the cost of conducting detailed on-site environmental assessments of all of that property would be cost-prohibitive. However, limiting the scope of on-site review increases the risk that an environmental issue or liability, such as an old landfill or historic mine workings that would be apparent from an on-site environmental assessment, goes undiscovered in the environmental diligence process.

2. Timing

A leave-no-stone-unturned approach to environmental due diligence is also often logistically infeasible. The timing considerations of the transaction will often have a significant bearing on the scope of environmental due diligence that can be conducted. Whether a deal is closing, a bid must be submitted, or an exclusivity period expires in two weeks or two months will inherently limit the amount of environmental due diligence that can be accomplished. The environmental due diligence team and the client should work together to identify the aspects of the transaction that have the highest potential for environmental issues and liabilities and prioritize diligence on those aspects of the transaction.

3. Confidentiality

Confidentiality considerations may impact the scope of environmental due diligence. In many transactions, the parties have entered into confidentiality and/or non-disclosure agreements that govern who may be involved in the environmental due diligence and who and how the environmental due diligence team conducts its activities. The terms of any such agreement must be considered in establishing the scope of the environmental due diligence. Even where a confidentiality agreement does not govern, practical considerations regarding disclosure of the transaction may limit the scope of environmental due diligence the client desires be conducted.

These confidentiality considerations can impact environmental due diligence in meaningful ways. For example, site environmental personnel often possess valuable information regarding a facility's compliance with environmental laws, but a buyer or potential buyer is often prohibited from interviewing that person due to confidentiality considerations regarding the potential transaction (i.e., that employee does not know about the transaction or potential transaction).

Similarly, state and local regulators are also often a key source of information regarding a facility's environmental compliance, but certain inquiries with these regulators may prematurely disclose that a transaction is being contemplated or is in the works. The degree to which an inquiry with a regulatory agency may prematurely disclose the existence of a deal to third parties depends on the nature of the inquiry and the relative prominence of the facility in question in the jurisdiction. A general non-facility-specific question can still lead to an inadvertent disclosure if the circumstances could allow the regulator to infer the target of the inquiry.

The environmental due diligence team must coordinate closely with the client to understand the confidentiality considerations of a deal and ensure that no diligence activities breach the terms of confidentiality agreements, involve personnel not intended to be aware of the transaction, or prematurely disclose the transaction to third parties. Where necessary diligence activities impact the confidentiality considerations, the buyer, seller, and due diligence team must all be involved in negotiating a resolution that satisfies the informational needs and confidentiality desires of the parties.

With careful consideration of the nature of the transaction and the nature of the asset(s) and a detailed discussion of the risks associated with limiting the scope of the various aspects of environmental due diligence, the environmental diligence team and the client can establish a scope of review that balances these limiting considerations with the informational needs necessary to properly assess and address the environmental risks of the proposed transaction. For example, the scope of on-site due diligence can often be tailored to focus on the core portions of the properties where operational activities occurred, or are occurring, or where documentation provided or other information reviewed indicates on-site investigation is warranted.

D. Documenting the Agreed Scope

Once the scope of environmental due diligence is established, it is important to document the agreed upon scope. This ensures that there are no misunderstandings between the client and the environmental due diligence team regarding the information reviewed to inform the assessment of the environmental compliance and environmental liability of the transaction target. Where the scope is limited in any manner that potentially creates a material data gap (i.e., material limitation on data room review or no on-site assessments), these should be specifically enumerated in the documentation of the agreed upon scope.

As noted in Section III.A. above, material changes in the nature of the transaction, assets involved, or information discovered during the due diligence may require alteration of the scope of the environmental due diligence being conducted. If such an event occurs, these changes in scope should be documented as well.

E. Addressing Scope in Deal Documents

It is important that the scope of the environmental due diligence is considered as the environmental representations and warranties, indemnity, and other terms are negotiated. Limitations on the scope of the environmental due diligence conducted may materially alter the terms a party is, or should be, willing to include. For example, many deal documents include provisions excluding anything disclosed in

the data room from the environmental representations and warranties being provided. The inclusion of such terms should be carefully considered in light of the data room review conducted to assess its impacts on the indemnification and other provisions being negotiated. Failure to consider the scope of the environmental due diligence conducted when negotiating the terms of the deal document can lead to undiscovered non-compliance or environmental liabilities being carved out of the indemnity simply because it is referenced in a document in the data room.

III. Organizing Environmental Due Diligence

After the scope of environmental due diligence is established and documented, it is important to effectively organize the due diligence process to efficiently accomplish the diligence tasks. A good starting point for this task is a good environmental due diligence checklist that has been tailored to the established scope for the environmental due diligence project.[9] The checklist should identify the tasks to be completed, the team members responsible for each task, and the anticipated deliverable.

Another important aspect is selecting the environmental due diligence team. The necessary players will depend heavily on the scope of the diligence and the types of assets involved, but will often include inside and outside counsel, company environmental and operational personnel, and environmental consultants. In retaining environmental consultants, care should be taken to ensure that confidentiality considerations are incorporated into the consultant's contracts. Often consultants are retained by counsel to afford as much protection as possible to the consultants' work product, but care should be taken to understand the limits on the protection of consultants' work product under such arrangements.[10]

IV. Documenting Environmental Due Diligence

Delineating the documentation that each team member will prepare early in the due diligence process ensures that each team member's work can be effectively utilized to inform the other team members' work and any final report or memorandum prepared. Certain aspects of due diligence, such as data room review and diligence requests and responses, are well suited to being documented in a spreadsheet or table format. Other aspects of due diligence, such as on-site assessments, are generally better suited to documentation in a written report or memorandum.

It should also be determined early in the process whether the client desires a final comprehensive memorandum or report summarizing all of the individual diligence tasks performed. Where such a document is desired, all team members should be made aware to ensure that they prepare work product that can easily be assimilated into the final environmental due diligence report or memorandum.

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[9] *See, e.g.*, *Handbook of Oil & Gas and Mining Transaction Due Diligence Checklists* (Rocky Mt. Min. L. Fdn. 2018).

[10] *See* United States v. Kovel, 296 F.2d 918 (2d Cir. 1961).

V. Identifying and Assessing Environmental Contamination Liability

One of the key aspects of environmental due diligence is assessing the risk of acquiring liability for environmental contamination, now or in the future, through the proposed transaction. Liability from environmental contamination can be imposed under various legal schemes; the most important, because of their sweeping reach and liability structures, are the federal statutes imposing liability for the cost of responding to environmental harm caused by the release of hazardous substances or disposal of hazardous wastes.

A. CERCLA

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") was enacted in 1980. CERCLA attaches sweeping liability to individuals and entities for costs incurred in the course of remediating releases—actual or threatened—of hazardous substances.[11] Hazardous substances are defined by reference to the provisions of other statutes designating materials as toxic or hazardous.[12] Notably for the mining industry, the courts have ruled that mining wastes excluded from regulation under the Resource Conservation and Recovery Act ("RCRA") are not excluded from the definition of hazardous substances for purposes of CERCLA.[13] Accordingly, CERCLA liability can arise from the management of common mining waste streams, such as tailings or waste rock, if those materials leach or otherwise release metals or other constituents into the environment.

Persons who may be held liable under CERCLA are (1) current owners and operators of property where hazardous materials were released; (2) past owners or operators; (3) persons who arranged for disposal of hazardous materials; and (4) transporters of hazardous materials for disposal.[14] CERCLA confers strict

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[11] 42 U.S.C. §§ 9601–9675.

[12] *Id.* § 9601(14) ("The term 'hazardous substance' means (A) any substance designated pursuant to section 311(b)(2)(A) of the Federal Water Pollution Control Act [33 U.S.C.A. § 1321(b)(2)(A)], (B) any element, compound, mixture, solution, or substance designated pursuant to section 9602 of this title, (C) any hazardous waste having the characteristics identified under or listed pursuant to section 3001 of the Solid Waste Disposal Act [42 U.S.C.A. § 6921] (but not including any waste the regulation of which under the Solid Waste Disposal Act [42 U.S.C.A. § 6901 et seq.] has been suspended by Act of Congress), (D) any toxic pollutant listed under section 307(a) of the Federal Water Pollution Control Act [33 U.S.C.A. § 1317(a)], (E) any hazardous air pollutant listed under section 112 of the Clean Air Act [42 U.S.C.A. § 7412], and (F) any imminently hazardous chemical substance or mixture with respect to which the Administrator has taken action pursuant to section 7 of the Toxic Substances Control Act [15 U.S.C.A. § 2606]. The term does not include petroleum, including crude oil or any fraction thereof which is not otherwise specifically listed or designated as a hazardous substance under subparagraphs (A) through (F) of this paragraph, and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel (or mixtures of natural gas and such synthetic gas).").

[13] Eagle-Picher Indus. v. EPA, 759 F.2d 922 (D.C. Cir. 1985) (holding that mining waste excluded from regulations under RCRA are hazardous substances under CERCLA if another element of the definition of hazardous substance is satisfied). *But see* United States v. Iron Mt. Mines, 812 F. Supp. 1528 (E.D. Cal. 1993) (articulating a minority position that mining wastes excluded from RCRA regulation are not hazardous substances even if another element of the definition of hazardous waste is satisfied).

[14] 42 U.S.C. § 9607(a).

liability[15] and limits defenses to those specified in the statute.[16] Although CERCLA liability is strict, it only attaches where a party satisfies the criteria for one of the statutory categories of liable parties.

1. Owners and Operators Under CERCLA

CERCLA liability attaches to both past and present owners and operators of contaminated land.[17] A person or entity need not be both an owner and an operator to be liable under CERCLA; rather, an entity or individual only needs to be found one or the other for liability to attach.[18]

(a) Fee Title Holders

Under *Chevron Mining Inc. v. United States*,[19] the holder of fee title, regardless of whether that person contributes to the creation or disposal of hazardous materials, is considered an owner and is liable under CERCLA.[20] The case, out of the U.S. Court of Appeals for the Tenth Circuit, pertained to national forest land that Chevron Mining mined for several generations under unpatented mining claims.[21] The court acknowledged that the United States in no way contributed to the disposal of the hazardous substances, but held that because CERCLA is a strict liability statute, "at a minimum, the term 'owner' covers fee title holders . . . irrespective of any additional indicia of ownership."[22] An Arizona district court case followed Chevron Mining's reasoning when it held that the United States was liable under CERCLA for remediation of land on the Navajo reservation.[23] The court reasoned that "[w]hile the United States has granted a significant property interest to the Navajo Nation—exclusive use and possession of reservation land, amounting to a compensable interest—the fact remains that the United States holds fee title and substantial powers over the land, including the power to enter, control alienation, and take," thus CERCLA liability was appropriate.[24]

(b) Contractors Hired to Perform Remediation

In the District of New Mexico, a contractor hired to perform remediation at a mining site was found to be liable under CERCLA as an operator after another contamination occurred during remediation. The court reasoned that "operator liability attaches 'if the defendant had authority to control the cause of the

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[15] *See, e.g.*, Chevron Mining Inc. v. United States, 863 F.3d 1261, 1270 (10th Cir. 2017) ("CERCLA holds 'covered persons' . . . strictly liable for remedial actions and other necessary response costs.").

[16] 42 U.S.C. § 9607(b).

[17] *Id.* § 9607(a)(1)–(2).

[18] *See, e.g.*, Redwing Carriers, Inc. v. Saraland Apts., 94 F.3d 1489, 1498 (11th Cir. 1996) ("It is therefore settled that a person is a responsible party under subsection 107(a)(1) if they are the current owner *or* operator of a facility.").

[19] 863 F.3d 1261 (10th Cir. 2017).

[20] *Id.* at 1277.

[21] *Id.* at 1265.

[22] *Id.* at 1277.

[23] El Paso Natural Gas Co. v. United States, No. 3:14-cv-08165, 2017 WL 3492993 (D. Ariz. Aug. 15, 2017).

[24] *Id.* at *5.

contamination at the time the hazardous substances were released into the environment.'"[25]

(c) Unwitting Purchasers of Contaminated Land at a Tax Sale

In the Ninth Circuit, the court recently found that a person who purchased contaminated land at a tax sale was liable under CERCLA, even though the buyer was unaware of the contamination.[26] The court held that the sale created a contractual relationship under California law[27] between the buyer and the previous owner, which then triggered CERCLA liability.[28] The court also decided that the contamination occurred "in connection with" the contractual relationship because the contamination was related to the previous owner's "status as a landowner."[29] This finding foreclosed any possibility of the purchaser asserting CERCLA's third party defense.[30]

(d) Other Factors That May Impact Owner-Operator Liability

Other factors that may impact an individual or entity's liability under CERCLA include site control,[31] the relationship between a parent company and its subsidiary,[32] whether or not the current owner interferes with or slows the progress of remediation;[33] whether state law permits corporate veil piercing,[34] and whether an indemnity agreement "is either specific enough to include CERCLA liability or

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[25] New Mexico v. EPA, 310 F. Supp. 3d 1230, 1246 (D.N.M. 2018) (quoting Kaiser Aluminum & Chem. Corp. v. Catellus Dev. Corp., 976 F.2d 1338, 1341 (9th Cir. 1992), *abrogated on other grounds by* Burlington N. & Santa Fe Ry. Co. v. United States, 556 U.S. 599 (2009)).

[26] Cal. Dep't of Toxic Substances Control v. Westside Delivery, LLC, 888 F.3d 1085 (9th Cir. 2018).

[27] This is because "under the current California tax-sale system, the government never holds title to or acquires any possessory interest in tax-defaulted property sold to a private party at auction." *Id.* at 1094.

[28] *Id*. at 1098.

[29] *Id.* at 1101.

[30] *Id.* (noting that the Second Circuit held differently in *Westwood Pharm., Inc. v. Nat'l Fuel Gas Distrib. Corp.*, 964 F.3d 85, 91–92 (2d Cir. 1992)).

[31] Next Millennium Realty, LLC v. Adchem Corp., 690 F. App'x 710, 714 (2d Cir. 2017) (unpublished) (finding sub-lessor defendants not liable as de facto owners because "while the imposition of liability [where the lessee is the active user and polluter] is surely correct, imposing *owner* liability instead of *operator* liability threatens to conflate the two statutorily distinct categories of potentially responsible parties) (citations omitted) (emphasis and alteration in original).

[32] N.Y. State Elec. & Gas Corp. v. FirstEnergy Corp., 766 F.3d 212, 223 (2d Cir. 2014) (finding a parent company not liable as an operator because it did not operate the facility in question "'in the stead of its subsidiary.' . . . The holding of dual officerships and directorships, without more, is insufficient . . . ."); *see also* United States v. Bestfoods, 524 U.S. 51, 71 (1998) (recognizing three situations in which a parent company may be considered an operator: "when the parent operates the facility in the stead of its subsidiary or alongside the subsidiary in some sort of a joint venture"; when "a dual officer or director might depart so far from the norms of parental influence exercised through dual officeholding as to serve the parent," or "an agent of the parent with no hat to wear but the parent's hat [that] manage[s] or direct[s] activities at the facility").

[33] Litgo N.J., Inc. v. Comm'r N.J. Dep't of Envtl. Prot., 725 F.3d 369 (3d Cir. 2013).

[34] Duke Energy Fla., LLC v. FirstEnergy Corp., 731 F. App'x 385 (6th Cir. 2018) (unpublished) (holding that the successor to a former corporate parent PRP could not be held directly liable under CERCLA because Florida law does not permit corporate veil piercing). *But see* Carter-Jones Lumber Co. v. LTV Steel Co., 237 F.3d 745 (6th Cir. 2001) (piercing the corporate veil may be appropriate in fraudulent or improper circumstances).

general enough to include any and all environmental liability which would, naturally, include subsequent CERCLA claims."[35]

2. CERCLA Arranger Liability

CERCLA also establishes liability for "any person who by contract, agreement, or otherwise arranged for disposal or treatment, or arranged with a transporter for transport for disposal or treatment, of hazardous substances . . . ."[36]

A recent Ninth Circuit decision noted that while the statute does not define disposal, a previous decision by an en banc panel of the court "held that the term 'deposit,' as used in CERCLA, 'is akin to putting down, or placement' by someone . . . ."[37] Therefore, the court reasoned, that arranger liability could not attach because hazardous substances that were emitted from a smelter's smokestacks could not be considered disposed under the statute because "[n]othing in the context of the statute or the term disposal suggests that Congress meant to include chemical or geologic processes or passive migration . . . ."[38]

The U.S. Supreme Court has held that in order to be held liable under CERCLA as an arranger, "knowledge alone is insufficient to prove that an entity 'planned for' the disposal" of a hazardous substance.[39] Rather, the person must have had the intention that a hazardous substance would be disposed of as described under § 6903(3).[40] A person "must 'own' or 'possess' the hazardous substance at issue"[41] in order to qualify as an arranger, even if the entity "helped arrange for the transport or disposal"[42] of the hazardous material. Additionally, when the disposal is "a peripheral result of the legitimate sale of an unused, useful product," arranger liability does not attach.[43]

3. Transporter Liability Under CERCLA

Anyone who transports a hazardous substance to a place from which there is a release, or a threatened release, of a hazardous substance, is liable under CERCLA as a transporter.[44] One is only considered a transporter if that person "either selected the disposal facility or had substantial input into deciding where the

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[35] Peoples Gas Light & Coke Co. v. Beazer East, Inc., 802 F.3d 876, 881 (7th Cir. 2015) (citations omitted).

[36] 42 U.S.C. § 9607(a)(3).

[37] Pakootas v. Tech Cominco Metals, Ltd., 830 F.3d 975, 983 (9th Cir. 2016) (internal quotation marks omitted) (citation omitted).

[38] *Id.* (alteration in original) (internal quotation marks omitted).

[39] Burlington Northern & Santa Fe Ry. v. United States, 556 U.S. 599, 612 (2009).

[40] *Id.*; *see also* 42 U.S.C. § 6903(3) (defining disposal as "discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters").

[41] Raytheon Constructors Inc. v. Asarco Inc., 368 F.3d 1214, 1219 (10th Cir. 2003).

[42] Chevron Mining Inc. v. United States, 863 F.3d 1261, 1279 (10th Cir. 2017).

[43] *Burlington Northern*, 556 U.S. at 612; *see also* Vine St. LLC v. Borg Warner Corp., 776 F.3d 312, 317 (5th Cir. 2015) ("This Court has long recognized the so-called 'useful product doctrine' . . . .").

[44] 42 U.S.C. § 9607(a)(4).

hazardous substance should be disposed."[45] However, it is not necessary for a plaintiff to show that the hazardous substance was actually released.[46]

4. CERCLA Defenses

CERCLA sets out certain defenses to liability. If the release of the hazardous substance was "caused solely by (1) an act of God; (2) an act of war; (3) an act or omission of a third party . . . or (4) any combination of the foregoing . . ." the person is not liable under CERCLA.[47] The third party defense is most commonly invoked,[48] but is construed quite narrowly.[49] Another available defense to CERCLA liability is the Contiguous Property Owner, which is a person who merely owned property that became contaminated due to a hazardous substance release "on contiguous or nearby property owned by someone else."[50] In 2002, Congress added the Bona Fide Prospective Purchaser defense to CERCLA. This defense protects parties that knowingly purchase contaminated land if they conduct "all appropriate inquiries" and meet certain obligations not to make contamination worse or interfere with any response action.[51]

Each defense (third party, Contiguous Property Owner, and Bona Fide Prospective Purchaser) requires that the defendant not know nor have reason to know of the contamination. Additionally, the defendant must show that she performed "'all appropriate inquiry' into the previous ownership and uses of property before acquisition of the property" and that she was not "potentially liable or affiliated with any other person who is potentially liable for response costs."[52] The Bona Fide Prospective Purchaser must also meet certain continuing obligations, including fully cooperating with remediation, taking steps to stop any release and prevent threatened release, not impeding remediation, and complying with any land use restrictions established in connection with the remediation.[53]

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[45] United States v. USX Corp., 68 F.3d 811, 820 (3d Cir. 1995).

[46] Prisco v. A&D Carting Corp., 168 F.3d 593, 606 (2d Cir. 1999).

[47] 42 U.S.C. § 9607(b).

[48] *See* Christopher D. Thomas, *Tomorrow's News Today: The Future of Superfund Litigation*, 46 ARIZ. ST. L.J. 537, 539 (2014) (noting "no court has ever declared God to be solely responsible for an act of contamination, and no major decision has endorsed the act of war defense"). The third party defense is also called the innocent landowner defense. 5 AM. L. OF MINING § 171.05 (2d ed. 2018).

[49] *See, e.g.*, Cal. Dep't of Toxic Substances Control v. Westside Delivery, LLC, 888 F.3d 1085, 1101 (9th Cir. 2018) (holding the third party defense inapplicable to an unsuspecting buyer who purchased contaminated property at a tax sale because the sale itself created a contractual relationship between the previous owner and the purchaser).

[50] 5 AM. L. OF MINING § 171.05 (2d ed. 2018).

[51] 42 U.S.C. § 9601(40).

[52] Memorandum from Susan E. Bromm, Director, Office of Site Remediation Enforcement, "Interim Guidance Regarding Criteria Landowners Must Meet in Order to Qualify for Bona Fide Prospective Purchaser, Contiguous Property Owner, or Innocent Landowner Limitations on CERCLA Liability," at 4, 5 ("Common Elements") (Mar. 6, 2003), https://www.epa.gov/sites/production/files/documents/common-elem-guide.pdf.

[53] 42 U.S.C. § 9607(Q)(1)(A).

B. RCRA

1. Corrective Action

The Resource Conservation and Recovery Act ("RCRA") mandates corrective action, or cleanup, when (1) there is an identified release of hazardous waste or hazardous constituents from waste, or (2) when EPA is considering a treatment, storage, and disposal facility ("TSDF") RCRA permit application.[54] Corrective action includes any or all of the following: "initial site assessment, site characterization, interim actions, evaluation of remedial alternatives, and implementation of the selected remedy."[55]

Unlike CERCLA, RCRA does not authorize "a private cause of action to recover the prior cost of cleaning up toxic waste that does not, at the time of suit, continue to pose an endangerment to health or the environment."[56] RCRA permits private citizens to initiate suits "against certain responsible persons, including former owners, 'who ha[ve] contributed or who [are] contributing to the past or present handling, storage, treatment, transportation, or disposal of any solid or hazardous waste which *may present* an *imminent* and substantial endangerment to health or the environment.'"[57]

C. Diligence Considerations

Liability under these statutes is a pervasive concern for the mining industry. Many naturally occurring metals such as arsenic, cadmium, antimony, selenium, and mercury are hazardous substances or wastes under CERCLA and RCRA. While the Bevill Amendment makes RCRA corrective action less of a concern at mining facilities, the risk of liability associated with hazardous waste shipped off-site is an issue for potential RCRA corrective action liability.

At the outset diligence should focus on whether there are any current, pending governmental actions asserting liability against the seller, in relation to assets or entities involved in the transaction. Diligence in this area should focus on the existence of any claims, proceedings, reports of releases, cleanup work, or other evidence of pending liability.

The more complicated part of due diligence, as it relates to liability for environmental contamination, is assessing the potential for latent environmental contamination liability. In assessing latent liability it is important to consider all of the forms liability can take under the statutes and mechanisms through which contamination can occur. Specifically, diligence should focus on assessing:

- Whether current operations or practices at facilities being acquired present a risk of future liability based on evidence of spills, containment breaches, poor storm water management, and other indicators that ore, process water,

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[54] EPA, *Learn about Corrective Action*, https://www.epa.gov/hw/learn-about-corrective-action.

[55] *Id*.

[56] Meghrig v. KFC W., Inc., 516 U.S. 479, 481 (1996) (noting one of CERCLA's purposes is to impose "all cleanup costs on the responsible party," whereas RCRA's purpose "is to reduce the generation of hazardous waste and to ensure the proper treatment, storage, and disposal of that waste which is nonetheless generated").

[57] *Id.* at 484 (alterations in original) (quoting 42 U.S.C. § 6972(a)(1)(B)).

tailings, or wasterock is handled in a manner that could contribute to the contamination of soils or groundwater.

- Whether there is evidence of historic mining operations at the site, or sites, being acquired, or at other sites presently or formerly owned by the seller.
- Whether wastes or other materials containing hazardous substances were shipped off-site for disposal from the site, or sites, being acquired, or from other sites presently or formerly owned by the seller.

Where this type of evidence is located during diligence, it is important to weigh the information to develop a reasonable understanding of the potential risk presented. This assessment should be objectively conveyed so that the client can determine the appropriate way to address the potential liability in the transaction.

VI. Assessing Environmental Compliance/Non-Compliance

The other key aspect of environmental due diligence is developing an understanding of the environmental compliance history of the facilities proposed to be acquired in a transaction. Non-compliance can take several forms. First, mining facilities are subject to a variety of permitting requirements under the environmental statutes. Many of these permitting programs are implemented by the states, so it is important to understand state-specific requirements that may be more stringent than the requirements under the federal environmental statutes. Second, many of the environmental statutes have reporting requirements applicable to operating mining facilities. Failure to comply with these reporting obligations can subject a facility to substantial penalties. Third, many of the environmental statutes have performance standards applicable to operating mining facilities, and non-compliance with these performance standards can be subject to penalties and other liability. The following sections provide an overview of some of the major statutes applicable to the mining industry. Every transaction, and the assets involved, is different. Each state's implementation of the major environmental programs varies. Accordingly, these summaries are not exhaustive—rather they are exemplary of the type of statutory and regulatory schemes that may apply in any given transaction.

A. Toxic Substances Control Act

The Toxic Substances Control Act[58] ("TCSA") regulates the use of harmful chemicals. Under the TSCA, the EPA may prohibit, restrict, or regulate any chemical substance or mixture that "presents an unreasonable risk of injury to health or the environment."[59]

TCSA is a complex statutory scheme containing many provisions regulating the manufacture and distribution of chemical substances, many of which are not generally relevant to the mining industry. In brief, they empower the EPA to (1) "promulgate testing rules requiring persons to conduct tests and submit data to EPA on specified chemicals"; (2) prohibit or limit the manufacture or distribution of chemicals; (3) institute civil actions in answer to "imminent hazards"; (4) and

[58] 15 U.S.C. §§ 2601–2697.

[59] *Id.* § 2605.

bring enforcement actions.[60] Additionally, TSCA (1) mandates manufacturers of new chemical processes—and those who "manufacture or process chemicals for 'significant new uses'"—to notify EPA before doing so and (2) subjects users of chemical substances to reporting and recordkeeping requirements.[61]

One of the most important provisions of TSCA as it applies to mining is the Chemical Data Reporting ("CDR") rule, which is "related to the reporting of mined metals, intermediates, and byproducts manufactured during metal mining and related activities."[62] Mining operations fall under the CDR rule because, according to EPA, "[m]ining is a manufacturing activity."[63] Specifically, "the act of processing or using one chemical substance (including a naturally occurring chemical substance) may result in the manufacture of a reportable chemical substance."[64]

A reportable chemical substance is one that is "manufacture[d], produce[d], or import[ed] for commercial purposes."[65] Consequently, the manufacture of materials "that have no commercial purpose" are not reportable under the CDR rule.[66] For example, a "byproduct manufactured for a commercial purpose, but not used for a commercial purpose after it is manufactured," is not a reportable chemical substance under the CDR rule.[67]

The CDR rule likewise does not require the reporting of chemical substances listed in 40 C.F.R. § 711.6, such as certain polymers, microorganisms, naturally occurring chemical substances, and forms of natural gas and water.[68] "Mined materials such as metal ores, minerals, and clays that are separated from the natural environment by only physical means are examples" of naturally occurring chemical substances and are not reportable under the CDR rule.[69] However, naturally occurring chemical substances become reportable if they are further processed in certain ways.[70] Many other mined minerals are reportable because they are "typically manufactured for a commercial purpose" and are not naturally occurring chemical substances.[71] The CDR rule also requires the reporting of an intermediate ("if it is produced in sufficient quantity" and no exception applies) and a byproduct (if it is manufactured for a commercial purpose and no exemptions apply).[72]

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[60] 5 AM. L. OF MINING § 178.01[1] (2d ed. 2018).

[61] *Id.*

[62] EPA, *TSCA Chemical Data Reporting Fact Sheet: Reporting Manufactured Chemical Substances from Metal Mining and Related Activities* (May 2016), https://www.epa.gov/sites/production/files/2016-05/documents/cdr_fact_sheet_metal_mining_5may2016.pdf.

[63] *Id.*

[64] *Id.*

[65] 40 C.F.R. § 711.3.

[66] *See supra* note 62.

[67] *Id.*

[68] 40 C.F.R. § 711.6.

[69] *See supra* note 62.

[70] *Id.*

[71] *Id.*

[72] *Id.*

In 2005, E.I. du Pont de Nemours and Company (DuPont) entered into a settlement agreement with the EPA to resolve violations of TSCA. DuPont's violations stemmed from a failure "to report monitoring data demonstrating the presence of PFOA in the bloodstreams of exposed pregnant female employees."[73] The settlement required DuPont "to pay $10.25 million in civil penalties and perform Supplemental Environmental Projects worth $6.25 million."[74]

B. Emergency Planning and Community Right-to-Know Act

In 1986, Congress enacted the Emergency Planning and Community Right-to-Know Act[75] ("EPCRA"), which "establishes a framework of state, regional, and local agencies designed to inform the public about the presence of hazardous and toxic chemicals, and to provide for emergency response in the event of health-threatening release."[76]

EPCRA imposes certain "reporting requirements" on "users of specified toxic and hazardous chemicals."[77] First, Section 311 requires owners and operators of facilities using hazardous chemicals to "submit a material safety data sheet for each such chemical" to state and local governments as well as to the local fire department.[78] Second, Section 312 requires specified owners and operators to prepare and submit annually an "emergency and hazardous chemical inventory form."[79] The form contains information such as the chemical names, amounts, and locations of the user's hazardous chemicals.[80] Third, Section 313 requires users to complete a "toxic chemical release form" each year for specified toxic chemicals that are "manufactured, processed, or otherwise used" in amount exceeding a certain threshold.[81]

Information reported under Section 313, known as the Toxic Release Inventory ("TRI") program, includes the name, location, and principal business activities of the facility and the use, release, and waste treatment activities for every listed toxic chemical at the facility subject to reporting.[82] The EPA then uses the forms "to provide information to the Federal, State, and local governments and the public, including citizens of communities surrounding covered facilities."[83]

As the Supreme Court has observed, "[e]nforcement of EPCRA can take place on many fronts. [EPA] has the most powerful enforcement arsenal: it may seek

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[73] *INSIGHT: Five Litigation 'Hot Spots' That Escalate the Stakes Under TSCA*, BLOOMBERG BNA (July 16, 2018), https://news.bloombergenvironment.com/environment-and-energy/insight-five-litigation-hot-spots-that-escalate-the-stakes-under-tsca.

[74] EPA, *E.I. DuPont de Nemours and Company PFOA Settlements*, https://www.epa.gov/enforcement/ei-dupont-de-nemours-and-company-pfoa-settlements.

[75] 42 U.S.C. §§ 11001–11050.

[76] Steel Co. v. Citizens for a Better Env't, 523 U.S. 83, 86 (1998).

[77] *Id.*

[78] 42 U.S.C. § 11021.

[79] *Id.* § 11022.

[80] *Id.*

[81] *Id.* § 11023.

[82] *Id.*

[83] *Id.* § 11023(h).

criminal, civil, or administrative penalties."[84] For example, EPA may assess a civil penalty each time owners or operators of facilities using specified toxic chemicals fail to notify the state emergency response commission in accordance with Section 302(c).[85] "State and local governments can also seek civil penalties, as well as injunctive relief."[86] Citizen enforcement suits are also permitted under the EPCRA.[87]

The reporting requirements of EPCRA apply to a "facility" in which "threshold amounts of relevant chemicals are present."[88] Because "facility" includes a broad array of places and items—such as buildings, equipment, structures, and "natural structures in which chemicals are purposefully placed"—"certain subsurface structures" are subject to the EPCRA reporting requirements.[89] The mining industry was not originally subject to TRI reporting requirements, under Section 313. In 1997, EPA extended the TRI reporting program to the mining industry.[90] Because of the breadth of activity that can fall within the definitions of "manufacture" and "process," activity such as moving waste rock must be reported if reportable chemicals are present in more than *de minimis* quantities.[91]

Recently, Veris Gold USA, Inc. was cited for violating EPCRA and, in 2014, settled with EPA.[92] According to EPA, while operating the Jerrit County mine in northern Nevada, Veris Gold committed violations that "involved late and incorrect reporting for ten chemical compounds including arsenic, cobalt, copper, cyanide, lead, mercury, nickel, propylene and zinc."[93] As part of the settlement agreement, Veris Gold agreed to a civil penalty of $182,000.

In 2013, Barrick Cortez, Inc., Barrick Gold US, Inc., and Homestake Mining Company also ran into trouble with the EPCRA.[94] The violations alleged included failing to submit "timely, complete and correct [TRI] reports in 2005, 2006, 2007 and 2008, for toxic chemicals" such as cyanide, lead, and mercury used in their mining operations.[95] As a result, the companies settled with EPA, agreeing to pay $278,000 in penalties and $340,000 to carry out an "environmentally beneficial project."[96]

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[84] Steel Co. v. Citizens for a Better Env't, 523 U.S. 83, 86 (1998) (citing 42 U.S.C. § 11045).

[85] 42 U.S.C. § 11045.

[86] *Steel Co.*, 523 U.S. at 86 (citing 42 U.S.C. § 11046(a)(2), (c)).

[87] *See, e.g.*, 42 U.S.C. § 11023.

[88] 5 AM. L. OF MINING § 171.09 (2d ed. 2018).

[89] *Id.*

[90] 62 Fed. Reg. 23,834 (May 1, 1997).

[91] Barrick Goldstrike Mines, Inc. v. Whitman, 260 F. Supp. 2d 28 (D.D.C. 2003).

[92] EPA, *EPA Requires Nevada Gold Mining Company to Correct Reporting Violations* (Sept. 25, 2014), https://www.epa.gov//enforcement/reference-news-release-epa-requires-nevada-gold-mining-company-correct-reporting.

[93] *Id.*

[94] EPA, *EPA Requires Nevada Gold Mining Companies to Correct Reporting Violations* (Feb. 6, 2013), https://archive.epa.gov/epapages/newsroom_archive/newsreleases/8dbdbc56192a186785257b0a006c2a12.html.

[95] *Id.*

[96] *Id.*

C. Clean Air Act

The Clean Air Act[97] ("CAA") was enacted "to combat a variety of air pollution problems, and to tackle emerging pollution threats."[98] Under the CAA, the EPA sets standards, known as National Ambient Air Quality Standards ("NAAQS"), and each state must meet those standards by "adopt[ing] [federally] enforceable plans to achieve and maintain air quality . . . ."[99] The CAA also mandates that areas that do not meet NAAQS be identified and that state plans include permitting and emission standards.[100]

Because of the amount and type of material released during mining operations, it is particularly important for mining companies to comply with the CAA. "Examples of mining-related situations that are covered by CAA-based regulations include dust emissions that accompany operations or tailings disposal in impoundments, exhaust emissions from heavy equipment, and emissions from processing facilities, such as smelters."[101] The CAA Prevention of Significant Deterioration ("PSD") program provides that "no major air pollutant emitting facility may be constructed unless the facility is equipped with 'the best available control technology' (BACT)."[102] "[A]pplication of the PSD program to fugitive dust emissions from mining operations has been the subject of intense controversy and prolonged litigation."[103] Title III of the CAA is the hazardous air pollution control scheme, which affects "virtually every industrial operation in the country, including mining operations."[104]

Both the EPA and state law require air permits for activities such as construction, modification, and operation. Thus, it is essential that mining operations are aware of and in compliance with all required permits. "Due diligence should focus on whether the facilities have all necessary air permits, as well as whether the facilities are in compliance with air permits. . . . [such as] state construction and minor source permits, and nonattainment permits or Prevention of Significant Deterioration (PSD) permits for newly constructed sources or modifications that have the potential to emit above major source thresholds."[105]

Under *Whitman v. American Trucking Associations*,[106] the U.S. Supreme Court noted that the CAA "unambiguously bars cost considerations from the NAAQS-setting process,"[107] which "implies that there's no limit to the amount the EPA

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[97] 42 U.S.C. §§ 7401–7671q.

[98] EPA, *Overview of the Clean Air Act and Air Pollution*, https://www.epa.gov/clean-air-act-overview.

[99] EPA, *Clean Air Act Requirements and History*, https://www.epa.gov/clean-air-act-overview/clean-air-act-requirements-and-history.

[100] *See* 5 AM. L. OF MINING § 168.01 (2d ed. 2018).

[101] *What are environmental regulations on mining activities?* AM. GEOSCIENCES INST., https://www.americangeosciences.org/critical-issues/faq/what-are-regulations-mining-activities.

[102] Alaska Dep't of Envtl. Conservation v. EPA, 540 U.S. 461, 468 (2004).

[103] 5 AM. L. OF MINING § 168.06[2] (2d ed. 2018).

[104] *Id.* § 168.09[1].

[105] Charlotte Neitzel & Colin Harris, *Assessing and Addressing Environmental Liabilities*, DUE DILIGENCE IN OIL AND GAS TRANSACTIONS 3-1, 3-16 (Rocky Mt. Min. L. Inst. 2011).

[106] 531 U.S. 457 (2001).

[107] *Id.* at 471.

could force emitters to spend . . . ."[108] However, the EPA recently issued a memorandum that "asks the [EPA's] independent Clean Air Scientific Advisory Committee to watch out for 'any adverse public health, welfare, social, economic, or energy effects which may result from various strategies for attainment and maintena[n]ce of such NAAQS.'"[109]

In January 2018, the EPA issued guidance that reversed long-standing CAA policy. The old policy, called "once in always in," mandated that once a facility was classified as a major source of hazardous air pollutants, it was always subject to major source standards, called Maximum Available Control Technology ("MACT").[110] Now, once a major source has proven that it has reduced pollutants below that described in the statute, the facility may be reclassified.[111] "[T]his updated guidance presents an opportunity to reward major emission sources who have invested the time and money to significantly reduce hazardous air pollutants and that now fall below the major source threshold."[112]

D. Clean Water Act

The Clean Water Act[113] ("CWA") regulates the discharge of pollutants into waters of the United States and sets standards to maintain water quality[114] in order "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[115] The CWA is enforced by both the Army Corps of Engineers and the EPA.[116] The CWA "prohibits 'the discharge of any pollutant by any person,' except in express circumstances. A 'discharge of a pollutant' is defined broadly to include 'any addition of any pollutant to navigable waters from any point source,' such as a pipe, ditch, or other 'discernible, confined and discrete conveyance.' And 'navigable waters,' in turn, means 'the waters of the United States, including the territorial seas.'"[117] Groundwater is commonly excluded from

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[108] Ronald Bailey, *Activists Decry Effort to Bring Economic Rationality to Clean Air Regulation*, HIT & RUN (May 11, 2018), https://reason.com/blog/2018/05/11/activists-decry-epa-effort-to-bring-econ.

[109] *Id.*

[110] EPA, *Reducing Regulatory Burdens: EPA withdraws "once in always in" policy for major sources under Clean Air Act* (Jan. 25, 2018), https://www.epa.gov/newsreleases/reducing-regulatory-burdens-epa-withdraws-once-always-policy-major-sources-under-clean. A "major source" is "one that emits, or has the potential to emit, 10 tons per year of any hazardous air pollutant, or 25 tons per year or more of any combination of hazardous air pollutants." *Id.*

[111] *Id.*

[112] John Lazzaretti & Lianne Mantione, *Amid Pushback, US EPA's Reversal on "Once In Always In" Policy Opens Door to Reduced Clean Air Act Obligations*, FRESH (Mar. 15, 2018), https://www.freshlawblog.com/2018/03/15/amid-pushback-us-epas-reversal-on-once-in-always-in-policy-opens-door-to-reduced-clean-air-act-obligations/.

[113] 33 U.S.C. §§ 1251–1388.

[114] EPA, *Summary of the Clean Water Act*, https://www.epa.gov/laws-regulations/summary-clean-water-act.

[115] Upstate Forever v. Kinder Morgan Energy Partners, L.P., 887 F.3d 637, 642 (4th Cir. 2018) (quoting 33 U.S.C. § 1251(a)).

[116] Timothy Cama, *Trump officials push states to take power over more waterways*, THE HILL (Aug. 7, 2018), http://thehill.com/policy/energy-environment/400686-trump-admin-pushes-states-to-take-power-over-more-waterways.

[117] Nat'l Ass'n of Mfrs. v. DOD, 138 S. Ct. 617, 624 (2018) (quoting 33 U.S.C. §§ 1311(a), 1362(7), (12), (14)); *see also Upstate Forever*, 887 F.3d at 643 ("The Supreme Court has interpreted

the definition of waters of the United States.[118] However, recent circuit court decisions have found that seepage into groundwater that eventually pollutes navigable waters is subject to the CWA.[119] The CWA "authorizes exceptions . . . in the form of permits issued in accordance with the National Pollutant Discharge Elimination System (NPDES) [under section 404 of the Act], which allows limited discharges."[120] Because mining often results in drainage, runoff, and other discharges to surface waters, regulation under the CWA is a common concern, and permits should be in place, or clear documentation confirming the facility's eligibility for an exemption, for operations discharging to a "water of the United States."[121]

Recently, the Ninth Circuit held that discharging effluent into groundwater wells that eventually made it to the Pacific Ocean constituted a violation of the CWA because, although the pollutant was not directly dumped into navigable waters, such a discharge was a violation because the pollutant ended up in navigable waters and a permit had not been obtained.[122] This decision is notable because the court rejected the argument that indirect discharge via groundwater was excluded from permitting under the CWA because groundwater is not subject to CWA permitting requirements.[123] The Fourth Circuit followed suit two months later in *Upstate Forever v. Kinder Morgan Energy Partner, L.P.*,[124] in which the court reversed a district court's determination "that the CWA did not encompass the movement of pollutants through ground water that is hydrologically connected to navigable waters."[125] The court reasoned that, because the CWA "does not place temporal conditions on the discharge of a pollutant," and because the CWA is a strict liability statute, indirect seepage of pollutants into navigable waters was a per se violation of the CWA.[126]

E. Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act[127] ("RCRA") regulates solid waste. RCRA's Subtitle C "gives EPA the authority to control hazardous waste from the 'cradle-to-grave.' This includes the generation, transportation, treatment, storage, and disposal of hazardous waste."[128] Solid waste is regulated under RCRA Subtitle D.[129]

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the term 'navigable waters' to mean more than waters that are navigable-in-fact, and to include, for example, wetlands and related hydrological environs.").

[118] 5 AM. L. OF MINING § 169.02 (2d ed. 2018).

[119] *See* Hawai'i Wildlife Fund v. Cnty. of Maui, 881 F.3d 754 (9th Cir. 2018).

[120] *Upstate Forever*, 887 F.3d at 642.

[121] *Id.*

[122] *Hawai'i Wildlife Fund*, 881 F.3d 754 (9th Cir. 2018).

[123] *Id.* at 762–63.

[124] 887 F.3d 637 (4th Cir. 2018).

[125] *Id.* at 645.

[126] *Id.* at 648.

[127] 42 U.S.C. §§ 6901–6987.

[128] EPA, *Summary of the Resource Conservation and Recovery Act*, https://www.epa.gov/laws-regulations/summary-resource-conservation-and-recovery-act.

[129] 5 AM. L. OF MINING § 170.01 (2d ed. 2018).

"Pursuant to . . . statutory mandate, [EPA] has adopted a scheme under which it deems a solid waste hazardous if the waste meets either of two conditions. One condition is that the agency has, after a rulemaking proceeding, specifically listed the waste as hazardous. The other condition is that the waste satisfies one or more of the following criteria that the agency has, by regulation, identified for hazardous waste: ignitability, corrosivity, reactivity, and extraction procedure toxicity. Either of these two conditions is sufficient for the agency to deem a 'solid' waste 'hazardous.' When the agency lists or identifies a waste as hazardous, the waste's treatment, storage, and disposal is usually regulated by permit."[130]

"[T]he definition of solid waste has a direct impact on the regulatory status of many materials routinely processed at smelters and refineries. If these 'secondary materials' fall within the regulatory definition of solid waste, they may also be regulated as hazardous wastes under Subtitle C."[131] "A solid waste is any discarded material . . ." that is abandoned, recycled, "inherently waste-like," or "a military munition identified as solid waste . . . ."[132]

RCRA contains special provisions applicable to mining and milling wastes. In 1980, Congress enacted the Bevill Amendment, excluding "solid waste from the extraction, beneficiation, and processing of ores and minerals" from regulation as hazardous waste until EPA submitted a study to Congress regarding regulation of mining waste under RCRA.[133] Subsequently, EPA submitted that study and significantly narrowed the regulatory exclusion for mineral processing wastes to 20 specified waste streams. All remaining mineral processing wastes became subject to regulation under RCRA Subtitle C.[134] All extraction and beneficiation wastes remain excluded from the definition of hazardous waste.[135]

In addition to the regulation of hazardous wastes, RCRA also provides a framework for regulation of existing, and cleanup of leaking, underground storage tanks ("USTs").[136] The UST program requires owners and operators of USTs to notify the designated state agency of the location, age, size, and type of any UST used to store petroleum of hazardous substances—referred to as "regulated substances."[137] The program provides minimum performance standards and design criteria for USTs used to store regulated substances.[138] In addition, owners and operators are subject to financial responsibility requirements to demonstrate that funds will be available to cover the cost of any corrective action.[139]

RCRA non-compliance can lead to significant penalties and cost to bring a facility into compliance. In June 2018, Decostar Industries, Inc. entered into a consent

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[130] Am. Mining Cong. v. EPA, 907 F.2d 1179, 1182 (D.C. Cir. 1990) (citations omitted).

[131] 5 AM. L. OF MINING § 170.01 (2d ed. 2018) (footnotes omitted).

[132] 40 C.F.R. § 261.2(a).

[133] 42 U.S.C. § 6921(b)(3)(A).

[134] 40 C.F.R. § 261.4(b)(7).

[135] *Id*.

[136] 42 U.S.C. §§ 6991–6991m.

[137] *Id.* § 6991a(a).

[138] 40 C.F.R. § 280.20.

[139] *Id.* § 280.90.

agreement with the EPA. The agreement mandates that "Decostar will implement a leak detection and repair program, perform a supplemental environmental project valued at over $2.7 million, and pay a $377,900 civil penalty."[140] The agreement stemmed from Decostar committing multiple violations that were largely preventable, such as "failure to conduct inspections; failure to maintain and operate the facility to prevent a release; failure to provide required training; and failure to establish and maintain emergency preparedness and prevention procedures."[141]

In 2017, Whole Foods entered a consent agreement after it "voluntarily disclosed to EPA that it may not have consistently made sufficient hazardous waste determinations on all solid waste streams (e.g., discarded consumer products) or complied with some of the 'universal waste' standards at all of its stores . . . ."[142] The agreement required Whole Foods to spend $2.75 million, which will be spent on replacing fluorescent bulbs in low income public schools and community centers, and on providing hazardous waste training.[143] Additionally, Whole Foods was required to pay a $500,000 civil penalty.[144]

Also in 2017, Innophos, a manufacturer of phosphoric acid for food and technical applications, was fined $1,398,000 for "sen[ding] toxic waste streams for disposal at a neighboring facility that was not permitted to receive them" and failing to send annual reports to the state department of environmental quality, among other violations.[145]

F. Diligence Considerations

Diligence with regard to compliance with the environmental statutes regarding pollution and toxic and hazardous materials should first focus on determining the applicability of permitting requirements, reporting obligations, and performance standards for a facility. Once the universe of applicable statutory and regulatory requirements is understood, the facility's compliance with those requirements can be assessed. Because every facility is different and many of these statutes are administered at the state or sometimes local level, it is important to begin by developing a working list of the potentially applicable environmental statutes and any state-specific issues in their implementation.[146] For example, Washington's implementation of RCRA does not recognize the Bevill Amendment, so diligence for any transaction involving assets in Washington will need to examine whether

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[140] EPA, *Decostar Settlement Information Sheet*, https://www.epa.gov/enforcement/decostar-settlement-information-sheet.

[141] *Id.*

[142] EPA, *Whole Foods Market Group, Inc. Nationwide RCRA Administrative Settlement*, https://www.epa.gov/enforcement/whole-foods-market-group-inc-nationwide-rcra-administrative-settlement.

[143] *Id.*

[144] *Id.*

[145] EPA, *Innophos Resource Conservation and Recovery Act Settlement* (Jan. 12, 2017), https://www.epa.gov/enforcement/innophos-resource-conservation-and-recovery-act-settlement.

[146] It is also important to assess state specific requirements that do not arise from the state's implementation of federal environmental statutes. For example, while the CWA does not generally regulate discharges to groundwater, many states have enacted laws and regulations requiring permits for and regulating allowable limits for discharges to groundwater. *See* Utah Admin. Code R317-6-1 to -6.

waste streams that would be exempt from RCRA regulation in other jurisdictions present a RCRA compliance issue. Once the working list of potentially applicable requirements is created, it can be narrowed to those that actually apply to the facility's system.

In determining the universe of applicable environmental statutes, regulations, and other requirements, it is important to obtain and review detailed information confirming any claim that an exclusion or exemption applies or that a requirement otherwise does not apply to a facility. For example, where a mining facility has not submitted TRI reports, it is important to ensure that the facility has correctly determined that it does not manufacture, process, or otherwise use listed chemicals in excess of the applicable thresholds.[147]

After the universe of applicable requirements under environmental statutes and regulations is identified, compliance with these requirements can be assessed. The assessment should focus on whether required permits are in place and being complied with (or can be obtained and complied with in the case of a not yet built project), applicable monitoring and reporting is being conducted and submitted, and applicable performance standards are being met.

VII. Environmental Due Diligence Tools

A. The Data Room

We have all heard about or experienced the horrors of conducting due diligence in a physical data room. However, days spent in a dusty warehouse combing through boxes of documents to identify relevant information regarding environmental liabilities or non-compliance with environmental laws are, for the most part, a relic of history. The data room in most modern transactions is electronic, giving the members of the diligence team authorized to access the data room the ability to review company provided information from the comfort of their own offices. Like the physical data rooms of old, electronic data rooms contain the seller's documents and information regarding the target(s) of the transaction.

The task of the environmental due diligence team in reviewing the data room is two-fold. First, the information in the data room should be reviewed, cataloged, evaluated, and summarized to understand what the information provided discloses regarding environmental liabilities and non-compliance with environmental laws. Second, the data room should be evaluated to determine what information regarding environmental compliance or environmental liabilities is not in the data room, but would be expected to be there based on the understood nature of the asset(s) involved in the transaction.

The first aspect involves reviewing, cataloging, and assessing the information provided for what is there, including:

- Environmental permits, permit applications, and supporting documentation. These documents provide valuable information regarding compliance obligations and the nature and types of contaminants, hazardous substances,

[147] 40 C.F.R. § 372.20.

wastes, and pollutants stored, handled, produced, emitted, discharged, or disposed of at, or from, the facility(ies) involved in the transaction.

- Monitoring, discharge, emission, spill, permit limit exceedance, manifests, and other documents required under environmental laws or permits. These documents allow the environmental due diligence team to catalog and assess compliance with applicable environmental laws and the terms and conditions of applicable permits. Some of the key reports that should be evaluated to assess compliance for an operational mine include: periodic monitoring and permit limit exceedance reports required under air and water quality permits,[148] hazardous waste manifests,[149] EPCRA Tier II reports,[150] EPCRA Toxic Release Inventory reports,[151] and reports to the National Response Center.[152]
- Compliance advisories, notices of violations, and similar documents alleging non-compliance with any local, state, or federal environmental law. These documents provide a catalog of the instances of non-compliance, which should be used to compare to other documentation in the data room regarding the resolution of each and every instance of non-compliance alleged. Documentation of the resolution may include follow-up correspondence from the agency, settlements, consent decrees, and penalty payments, among others. These documents should be carefully reviewed for an understanding of the resolution of the violations alleged, but also for any ongoing requirements or obligations established by the settlement.

  The other value of these types of documents is their utility in assessing whether violations are singular occurrences or are a trend. A trend of similar violations is often indicative of operational or infrastructure issues that may require costly upgrades to remedy.
- Notices, claims, demands, or requests for information,[153] corrective or unilateral orders,[154] and the responses thereto, regarding liability for environmental contamination, disposal of hazardous waste, or releases or threatened releases of hazardous substances. These documents should be reviewed with care to identify and assess the nature and extent of potential liability. Documentation in the data room regarding settlements, consent decrees, judgments, or other resolutions of liability for environmental contamination should also be reviewed to understand the resolution of the

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[148] *See, e.g.*, *id.* § 70.6(a)(3) (establishing minimum compliance monitoring and reporting requirements for Title V operating permits).

[149] *Id.* §§ 262.20–.27.

[150] *Id.* §§ 370.20–.45.

[151] *Id.* §§ 372.20–.38.

[152] *Id.* § 302.6.

[153] *See, e.g.*, 42 U.S.C. § 9604(e)(2) (authorizing representatives of the president (i.e. the EPA) to require any person to provide relevant information regarding releases or threatened releases of hazardous substances, circumstances likely to lead to such a release or threatened release, and the person's ability to pay for or perform cleanup).

[154] *See, e.g.*, *id.* § 9606(a) (authorizing representatives of the president (i.e. the EPA) to order a party to take action where there "may be an imminent and substantial endangerment to the public health or welfare or the environment because of an actual or threatened release of a hazardous substance").

issues and any ongoing requirements or obligations associated with the issues identified in these documents.

- Environmental assessments, audits, investigations, remediation reports, and other internal documents or data. Many mining companies maintain environmental management systems that contain detailed information regarding the environmental performance of their facilities. These companies also perform periodic environmental audits where environmental professionals from other facilities within the company and external auditors review a facility's environmental performance. Documentation from both of these sources is a valuable source of information regarding issues that could lead to liability for environmental contamination or non-compliance with environmental laws that has not been discovered by or disclosed to regulators.
- Contracts, agreements, and other documents. It is often unreasonable for the environmental due diligence team to review all of the documents in the entire data room. Where portions of the data room are not being reviewed by the environmental due diligence team, other members of the larger diligence team should be asked to inform the environmental due diligence team if they encounter documents such as contracts for waste disposal, agreements with environmental indemnification provisions, or other documents that indicate a potential for liability or evidence non-compliance with environmental laws. For example, a contract to excavate and dispose of contaminated soil that is not disclosed elsewhere in the data room may indicate a release of oil or a hazardous substance that was not reported to regulators, or a contract to repair or replace a liner for a tailings impoundment or process water pond may indicate an issue with the performance of the previous liner.

The second aspect then assesses what is missing but would be expected to be there based on the nature of transaction, the assets involved, and the information reviewed in the data room. For instance, where the nature of an asset and the information reviewed indicate that a certain permit is required, but no permit has been located in the data room; where a permit includes a periodic reporting requirement, but no reporting documents have been provided; or where documents in the data room indicate that a spill or other release of hazardous substances occurred, but no information has been provided regarding reporting or remediation of the spill or release. Where it appears that documents are missing that would reasonably be expected to exist for the type of operation in question, in light of the information provided, follow-up through diligence requests should be tailored to obtain the missing documents or confirm their non-existence.

Many sellers set temporal limits on the information placed in the data room. Often compliance records, reports, and other information is only provided for the most recent several years. It is important to understand the temporal limitations the seller is placing on the information being placed in the data room and consult with the client regarding the reasonableness of the limitation. In considering how many years of compliance information are reasonable, factors to consider include: the applicable statutes of limitation for the government to bring an enforcement action or a citizen suit to be filed, the applicable statute of limitations for cost recovery

claims, and the length of time the seller has owned the assets. Where the assets involved were recently acquired in a transaction that includes strong environmental indemnities and/or insurance it may be reasonable to limit the compliance information to the time period since that transaction closed.

B. Diligence Requests

In most transactions there are multiple opportunities for the buyer to submit diligence requests or questions to the seller. The process, timing, and number of requests allowed are often negotiated between the parties or dictated by the seller, particularly in a bid process. It is imperative that the environmental due diligence team understand any applicable limitations on diligence requests to ensure that requests are tailored to obtain relevant and important information regarding environmental liabilities and instances of non-compliance with environmental law. Even where there are no established limitations on number and timing of diligence requests, care should be taken to avoid sending boilerplate diligence requests that have not been tailored to account for the nature of the transaction or the assets involved. Diligence requests can essentially be divided into two categories: initial diligence requests and follow-up requests.

Initial diligence requests are valuable to obtain the seller's summary of important environmental liability and compliance issues, for establishing the information that buyer expects to see populated in the data room, confirming that the information provided in the data room meets those expectations. The Sample Environmental, Health and Safety Matters Due Diligence Checklist available from the Foundation is a good starting point for crafting initial diligence requests, but it should be tailored to the specific needs of each project.[155] Environmental diligence requests should be crafted to solicit narrative responses, but, in practice, it is rare to receive a response to an initial request more detailed than "see data room."

Follow-up diligence requests should be specifically crafted to solicit additional information about issues of concern identified in other facets of the due diligence process. These questions should be targeted and directly request a narrative explanation of the issue, its current status, and expected resolution. Any and all documents in the seller's possession relating to the issue should also be requested. For example, where other diligence identifies a spill or release of oil or a hazardous substance, but additional documentation regarding the response to the release is not provided, a follow-up request should be prepared. The diligence request should be tailored to solicit information including: the response action taken, any post-response sampling, reporting of the spill to local, state, or federal environmental regulators or justification for not reporting the spill, correspondence from any regulator, and any notice order, fine, or penalty associated with spill. Follow-up diligence requests provide the seller an opportunity to provide documentation that an apparent issue has been addressed appropriately.

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[155] *See Handbook of Oil & Gas and Mining Transaction Due Diligence Checklists* (Rocky Mt. Min. L. Fdn. 2018).

C. Online Research

1. EDGAR

EDGAR is a database of Securities and Exchange Commission ("SEC") filings submitted by publicly traded companies.[156] Where the seller is a publicly traded company, these filing are often a useful source of information about the company and its operations. Many securities filings contain sections where the company identifies the issues and risk factors, including pending litigation, enforcement efforts, or anticipated legislative or regulatory changes affecting the business that are useful in informing the diligence process. While these self-reported risk assessments should not be fully relied on, they can be particularly beneficial in informing the scoping effort.

2. ECHO

EPA's Enforcement and Compliance History Online ("ECHO") database contains information on compliance and enforcement under the Clean Air Act, Clean Water Act, Resource Conservation and Recovery Act, Safe Drinking Water Act, and Emergency Planning and Community Right-to-Know Act.[157] ECHO can be searched by facility name, facility type, locations, and a host of other criteria.[158] ECHO includes information on permits, monitoring, reporting inspection history, and a three-year compliance history for the state and federal regulatory programs under the above statutes.[159] ECHO should be used as a gateway screening tool to identify issues and establish a basic understanding of the environmental permits and reporting for the facility and the history of compliance. Information derived from ECHO should be considered a starting point and follow-up regarding any issues identified is almost always warranted. EPA also maintains a database of significant civil and administrative cleanup and enforcement cases and settlements that can be searched to confirm information provided, or lack of information provided, in the data room.[160]

3. GoogleEarth

GoogleEarth is a powerful tool in scoping environmental due diligence. GoogleEarth imagery can be used to provide an overview of a site and identify areas of disturbance or other features that may warrant further investigation. This can be particularly useful where transactions involve more acreage than can practically be reviewed during an on-site assessment while a useful tool—care should be taken to not overly rely on such imagery.

4. State Environmental Protection Agency Websites

The quality and quantity of information available online from state environmental protection agencies vary considerably from state to state. Most state websites contain information on major permitting, enforcement, rulemaking, and other activity.[161] Some provide detailed information and copies of permits for regulated

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[156] https://www.sec.gov/edgar/searchedgar/companysearch.html.

[157] EPA, *Enforcement—Data and Results*, https://www.epa.gov/enforcement/data-and-results.

[158] EPA, ECHO, https://echo.epa.gov/facilities/facility-search.

[159] *Id.*

[160] EPA, *Civil Cases and Settlements*, https://cfpub.epa.gov/enforcement/cases/.

[161] *See, e.g.*, https://deq.utah.gov/.

facilities,[162] spill reporting databases,[163] and detailed information about cleanup activities within the state.[164] State websites also often contain databases of underground storage tanks.[165]

5. SEMS

EPA's website provides an interface to search information in the Superfund Enterprise Management System ("SEMS"), which contains data on sites being investigated or cleaned up under CERCLA.[166] SEMS can be searched by facility name or location. Name searches may identify sites where the target is listed as a PRP. Location searches are useful to identify any CERCLA sites in the vicinity of the target. Other EPA databases and information sets can then be searched to access additional information on the site.[167]

D. On-Site Investigations

1. Environmental Site Assessments

Phase I Environmental Site Assessments, performed by qualified environmental professional,[168] are useful for two reasons. First, they provide detailed information about environmental conditions at the site, discernable from a surface inspection of the property, and identify issues requiring follow-up. Second, a Phase I prepared in compliance with ASTM International Standard E2247-16 is required to qualify for innocent landowner or bona fide prospective purchaser defenses to CERCLA liability.[169]

Where the results of a Phase I or other due diligence indicate further inquiry is warranted, Phase II assessment work may be necessary to identify the nature and extent of contamination. Phase II work can include surface soil sampling, borings to collect sub-surface soil samples, or groundwater sampling.

For mining transactions, the use and utility of Phase I and Phase II Assessments should be discussed and appropriately scoped. Some key considerations in whether and where to perform Environmental Site Assessments include: whether qualifying for defenses to CERCLA which require a Phase I be performed prior to acquisition of the property is possible or desired by the buyer;[170] whether the amount of land involved makes it feasible to conduct a Phase I on the all of the land involved; and whether the existing monitoring information required under the

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[162] *See, e.g.*, https://deq.utah.gov/water-quality/current-updes-permits.

[163] *See, e.g.*, http://eqspillsps.deq.utah.gov/.

[164] *See, e.g.*, https://documents.deq.utah.gov/environmental-response-and-remediation/cercla/voluntary-cleanup-brownfields/DERR-2018-002841.pdf.

[165] *See, e.g.*, https://deq.utah.gov/environmental-response-and-remediation/lists-underground-storage-tanks-branch.

[166] EPA, *SEMS Overview*, https://www.epa.gov/enviro/sems-overview.

[167] *See* EPA, *Superfund Data and Reports*, https://www.epa.gov/superfund/superfund-data-and-reports.

[168] *See* 40 C.F.R. § 312.10.

[169] *Id.* § 312.11. A Phase I must be prepared in compliance with the regulatory requirements set forth in 40 C.F.R. §§ 312.21–.31, but the regulations provide that a Phase I prepared in compliance with the ASTM Standard is deemed to satisfy these requirements—making ASTM compliance the *de facto* standard.

[170] *See* 42 U.S.C. § 9601(40).

facilities operating permits satisfies the information needs. Where sampling work is to be undertaken, care should be taken to ensure that appropriate access rights have been negotiated with the buyer. Where a Phase I isn't prepared, an EDR[171] report, which many environmental professionals use as the basis of their Phase I, can be ordered, which can provide useful information about potential liabilities at a facility or associated with a business entity derived from searches of numerous local, state, and federal databases and other sources of information.

2. Operational Inspections

An on-site inspection of the facility by environmental and operational personnel and the diligence team can also be helpful to identify issues at the mine that would go undiscovered in a desktop review. Suspect environmental management practices and operational procedures observed during a site visit should be cataloged and reported, and appropriate follow-up should be conducted.

VIII. Addressing Environmental Liabilities

As with most other aspects of due diligence, there are multiple options to consider in addressing a finding of potential non-compliance or environmental liability. Many of these are not unique to environmental due diligence; however, there are some unique options and some special considerations for addressing potential environmental liabilities.

A. Transactional Provisions

As with any adverse diligence finding, there are multiple tools available to address potential environmental liabilities in the actual deal documents. Indemnities and other contractual provisions can be used to allocate costs of non-compliance, cleanup, or other environmental liabilities among the parties. However, it is important to remember that these mechanisms only allocate responsibility for the cost associated with an environmental liability among the parties; they do not absolve a party of liability as to third parties.[172] Moreover, courts have ruled in various contexts that general indemnity language is often insufficient to effectively allocate responsibility for CERCLA liability by contract.[173] Accordingly, great care must be taken where responsibility for environmental liabilities is being allocated between buyers and sellers.

B. Regulatory Tools

Where environmental non-compliance or liability is identified in the diligence process, parties may be able to take advantage of various regulatory tools to mitigate liability. It is important to note that these tools will not generally eliminate risk, but can limit the risk posed by discovered environmental conditions sufficiently to allow a transaction to proceed.

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[171] EDR is a commercial service that can search databases of information regarding potential contamination and summarizes the information available.

[172] *See, e.g.*, 42 U.S.C. § 9607(e)(1).

[173] *See* Blasland Bouck & Lee, Inc. v. City of North Miami, 283 F.3d 1286 (11th Cir. 2002).

1. Comfort/No Further Action Letters

As noted above, CERCLA provides several self-executing defenses to liability that can protect buyers, if certain standards are met. Because these defenses are self-executing, buyers are often nervous as to whether a court will actually agree that the criteria to qualify for the defense were met.[174] States and the EPA will sometimes provide comfort letters that state that the criteria for a defense have been satisfied. But these letters are usually limited by reference to the facts represented to the agency and are not legally binding.

Buyers can also sometimes negotiate to receive a legally enforceable commitment from a state in return for agreeing to perform certain cleanup work or to take other actions to ensure that harm to the environment is limited. These assurances generally occur under two scenarios. First, under a state's voluntary remediation program a party can agree to perform certain cleanup work, and when the work is complete, the state will issue a no-further action letter or similar document that provides a limited release of liability for the contamination addressed.[175] The state will also sometimes issue an enforceable written assurance stating that a buyer qualifies as a bona fide prospective purchaser so long as the buyer complies with certain obligations enumerated in the written assurance.[176]

These tools can be useful for mitigating risk, but it is important to remember that these are mainly implemented on the state level so a detailed understanding of the state specific requirements to qualify and obtain these types of assurances is required. Moreover, the limitations of the protections afforded should be fully examined to determine if the protections provided are truly sufficient to address the liability concerns discovered during due diligence.

2. New Owners Audit Policy

Where evidence of non-compliance with environmental laws is identified in the diligence process, EPA and most states have mechanisms under which new owners can self-disclose violations and avoid or substantially mitigate potential penalties for the violations.[177] EPA's audit policy provides for substantial penalty mitigation for violations that are discovered through a systematic audit and self-disclosed, so long as certain conditions are satisfied.[178] For new owners, EPA relaxes several of the conditions, to provide new owners flexibility in discovering and disclosing violations, within the first nine months after closing, by entering into a comprehensive audit agreement with the EPA.[179] The protections afforded under the new owner audit policy do not necessarily apply to sellers so it is

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[174] *See* Memorandum from Cynthia L. Mackey, EPA Office of Enforcement and Compliance Assurance, and Thomas A Mariani, Jr., U.S. Dep't of Justice Environmental and Natural Resources Division, to Superfund National Program Managers, Regional Counsels, and Environmental Enforcement Division Deputy Chiefs and Assistant Chiefs, *Agreements with Third Parties to Support Cleanup and Reuse at Sites on the Superfund National Priorities List* (Apr. 17, 2018).

[175] *See, e.g.*, Utah Code Ann. § 19-8-113.

[176] *See, e.g.*, Utah Admin. Code R311-600.

[177] 73 Fed. Reg. 44,991 (Aug. 1, 2008); Utah Code Ann. §§ 19-7-101 to -109.

[178] 65 Fed. Reg. 19,618 (Apr. 11, 2000).

[179] 73 Fed. Reg. at 44,997.

important to understand the seller's exposure under the specific transaction being pursued to penalties for disclosures made by the buyer.

C. Insurance

Environmental liability insurance has become an increasingly common way to allocate the risk of unidentified environmental risks in many transactions, but is not as common in mining transactions. These policies will generally cover the cost of unknown environmental liabilities for a period of time after closing. Essentially, the policy allocates the risk of loss to the insurance market rather than the buyer or the seller. If insurance is being considered, it is important to fully understand the scope of coverage being provided and ensure that excluded liabilities are otherwise addressed.

IX. Seller Side Due Diligence Considerations

While the majority of this paper has focused on environmental due diligence from the buyer's perspective, seller side diligence considerations also merit some discussion. Seller side environmental due diligence should be designed and conducted to ensure that environmental issues and liability associated with the assets being sold are understood before they are raised by a potential bidder or a buyer.

The most important aspect of due diligence from the seller's perspective relates to identifying and selecting relevant environmental documents to place in the data room. Sellers will need to determine the universe of relevant environmental documents that exist and decide how many years of reporting and compliance documents they intend to provide. While there is an inherent arbitrariness in setting any cut-off date, there are several common sense places the line can be drawn

In selecting documents to place in the data room it is important to balance the need to include documentation of important environmental issues with protecting the confidentiality of certain privileged information. While it is possible to disclose information in a transaction in a manner that does not destroy a privilege claim, there is a substantial risk that such disclosures will jeopardize a future claim of privilege.[180] Prudent sellers should assume that any document they place in a data room, particularly in the early stages of a transaction where there are multiple bidders, is no longer privileged. Accordingly, documents of internal audits or investigations conducted at the direction of counsel should be carefully assessed before they are placed in a data room.

Complete disclosure of relevant issues upfront can often be a benefit to the seller. Buyers often react less favorably to the discovery of an environmental issue than they do if the same issue is identified by the seller, in the data room or otherwise. Sellers should do sufficient advance environmental due diligence to understand the permitting and compliance history of the assets being sold and where potential liability exists for environmental contamination or conditions.

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[180] Libbey Glass, Inc. v. Oneida, Ltd., 197 F.R.D. 342 (N.D. Ohio 1999); Hewlett-Packard Co. v. Bausch & Lomb, Inc., 115 F.R.D 308 (N.D. Cal. 1987).

X. Conclusion

The cost associated with significant non-compliance with environmental laws or environmental contamination can add up quickly, with the costs of addressing environmental contamination exceeding $100 million in some instances. Maximum penalties under the environmental statutes commonly can exceed $50,000 per day, per violation. These types of liabilities can fundamentally alter the value proposition of a transaction. Properly scoped and executed environmental due diligence should provide buyers an evaluation of the risk of such liabilities in the proposed transaction so that appropriate consideration of that risk can be negotiated into the transaction.

Regulatory Roulette: Preparing for Potential Filings Under HSR and CFIUS

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Synopsis

I. Introduction

Due diligence exists both to confirm known facts and to try to uncover facts previously not known or at least poorly understood. It's a little bit like the classic

board game Clue®,[1] in which you methodically gather various pieces of evidence and try to deduce the correct answer, though in due diligence you typically work together with a coordinated team rather than each member acting separately, secretly and against each other. In the game of due diligence, the winner is the one that gathers the most, and best, information and properly analyzes and characterizes that information in a manner that allows the client to pursue its transaction in a fully informed manner. Leaving secrets behind and jumping to conclusions on insufficient information may lead to an early and unsatisfactory exit from the game.

An often overlooked, but increasingly important and prominent clue, involves the potential role of the Committee on Foreign Investment in the United States ("CFIUS"). CFIUS monitors and attempts to balance two important national policy goals that periodically conflict: (1) encouraging foreign direct investment in the United States, which tends to fuel economic growth and vitality while also encouraging reciprocity for U.S. companies making acquisitions in foreign countries, and (2) protecting vital U.S. national security interests.

While the Hart-Scott-Rodino Antitrust Improvements Acts of 1976, as amended ("HSR Act"), is better known, at least on a superficial level, it is often poorly understood by natural resources practitioners pursuing a mining, oil and gas or energy transaction. Failing to account for HSR Act issues at the due diligence stage may lead to unpleasant results.

The President of the United States has the authority to block and unwind certain acquisitions when they raise national security risks or to impose mitigation measures to ameliorate those risks, sometimes in a manner that may defeat the investment expectations of a buyer and a seller. Although this may on its face strike the natural resources practitioner as an esoteric oddity not worthy of worry, CFIUS and the President have on several occasions exercised this authority to block and unwind natural resources transactions that on their face seem ordinary and unremarkable. Transactions that have encountered resistance, leading to the scuttling of the parties' business intentions, after spending significant sums of money in pursuit of closing a deal, include a proposed acquisition of (1) a majority ownership of a defunct, previously bankrupt, non-producing gold mine; (2) a majority ownership of unremarkable precious metals exploration properties; and (3) a wind farm along the Columbia River.

Just like the acquisitions that they support, due diligence projects range from large to small; and from covering basic topics like land title, environmental compliance, and corporate records to more esoteric, but potentially consequential, topics like the alphabet soup of CFIUS and the HSR Act addressed by this paper. For the uninitiated, while some due diligence projects may lead to the need to revise deal terms, CFIUS and the HSR Act may lead to the U.S. government prohibiting the transaction. Without adequate diligence and attention, CFIUS and the HSR Act may turn into traps that derail the best laid plans, leading to an early, and costly, exit from the game.

[1] The board game Clue is made and marketed by Hasbro. The inventor of Clue developed the game in Britain during World War II to occupy time during German bombing raids over London. http://www.cracked.com/article_18995_5-classic-board-games-with-disturbing-origin-stories.html.

II. CFIUS

CFIUS is a federal interagency committee charged with reviewing foreign direct investment into the United States to identify, analyze and address the potential effect of such transactions on the national security of the United States. On August 13, 2018, the President signed into law the John S. McCain National Defense Authorization Act, which included, as one of its many provisions, the Foreign Investment Risk Review Modernization Act of 2018 ("FIRRMA"), which substantially modifies the CFIUS process. FIRRMA was the first update to the U.S. foreign investment review laws in over a decade. Given its recent enactment, the full impact of the clues FIRRMA provides for due diligence in natural resources transactions still are being analyzed. In addition, it is important to recognize that FIRRMA updates, but does not replace, the existing CFIUS process. As a result, this paper will address CFIUS as it existed prior to the enactment and effectiveness of FIRRMA, will summarize several key provisions of FIRRMA, and will note areas of practice that are expected to change as FIRRMA becomes effective and as the Department of the Treasury begins to issue regulations implementing FIRRMA.

CFIUS is covered as part of this Due Diligence Special Institute since a careful practitioner must consider the effect of the CFIUS process any time a foreign party acquires a U.S. business or makes an investment in a U.S. business. In an increasingly globalized world, potential purchasers of assets and businesses located in the United States often ultimately have foreign ownership. Typically, a seller merely wants to maximize the purchase price and is indifferent as to whether the buyer is U.S.-based or based in another country. The presence of a foreign buyer interjects particular concerns and considerations for the seller to analyze prior to accepting a bid from a foreign buyer, since a foreign buyer may introduce additional risk and uncertainty into the transaction, and particularly into the process and timing for closing a transaction.

Through the CFIUS process, the President has the authority to review and assess specified transactions involving a foreign buyer, and pursuant to this authority, the President may suspend or prohibit transactions that have been proposed and to unwind transactions that have been completed, all in the name of protecting U.S. national security. While the casual observer may incorrectly assume that this must only apply to transactions involving military contractors and suppliers or other related industries that similarly come to mind when contemplating national security, in fact, a number of the transactions that have been suspended, blocked or unwound, or at least subject to close and special scrutiny, have involved ordinary course natural resources transactions involving mining, oil and gas and wind farms.

A. History of CFIUS

President Ford established CFIUS in 1975 pursuant to an Executive Order.[2] In 1973, the Organization of Petroleum Exporting Countries ("OPEC") imposed an oil embargo on the United States, which had serious, far-reaching and long-lasting repercussions on the U.S. economy. One consequence was a growing unease with the significant wealth held by the OPEC countries and a fear that OPEC investments in the United States were driven primarily by political goals, rather

[2] Executive Order 11858, May 7, 1975, 40 Fed. Reg. 20263

than purely economic motives, and may serve as a precursor to undermining U.S. national security. Since President Ford initially established CFIUS, most of the significant revisions to the laws and regulations governing CFIUS have been driven by periods of heightened concern in the United States with the perceived motives behind foreign direct investment into the United States, typically focusing on a particular foreign country or region of concern. President Ford's initial Executive Order, while only three pages long,[3] established the basic CFIUS principles that continue to guide fundamental aspects of the process, including (1) CFIUS would be a multi-agency committee, (2) the Department of the Treasury would chair CFIUS, (3) CFIUS would have the primary responsibility for monitoring and coordinating U.S. policy on foreign direct investment,[4] and (4) the review process, and information provided in connection with such review, would remain confidential.[5] While the executive branch now had a tool to deploy in trying to monitor and manage the perceived threat of foreign investment, for many years, it was little used and poorly understood, both in and outside of government.

By the mid-1980s, Congress and the public had grown increasingly concerned about a significant rise in foreign investment in the United States, particularly from Japan, whose economy had expanded rapidly at a time when a number of Americans felt that the American economy was stagnating and in decline. Japanese companies contemplated a number of high-profile acquisitions in the United States that garnered headlines, ranging from movie production companies to high profile real estate.[6] Congress reacted to this heightened concern about foreign investment by bolstering CFIUS and providing it with a clearer set of principles. In 1988, Congress approved the Exon-Florio amendment to the Defense Production Act,[7] which codified the CFIUS process and provided detailed provisions for the review of foreign investment. The Exon-Florio amendment gave the President the explicit authority to block proposed acquisitions of U.S. businesses by foreign parties when the transaction threatened to impair U.S. national security. President Reagan issued an Executive Order to implement provisions of the Exon-Florio amendment, including by delegating to CFIUS the presidential authority to administer the Exon-Florio requirements and by detailing the role of CFIUS in receiving notices and ordering investigations of foreign investments.[8] The Exon-Florio amendment and Executive Order 12661 converted CFIUS from a little-used, poorly understood executive branch body that collected

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[3] Compare the three-page establishment of CFIUS with the recently enacted FIRRMA, which weighs in at 34 pages to revise CFIUS. *See* Title XVII of the John S. McCain National Defense Authorization Act of 2018 – Review of Foreign Investment and Export Controls, P.L. 115-232, August 13, 2018

[4] Executive Order 11858 stated that CFIUS would have "the primary continuing responsibility within the executive branch for monitoring the impact of foreign investment in the United States, both direct and portfolio, and for coordinating the implementation of United States policy on such investments."

[5] *Id.*

[6] https://www.businessinsider.com/japans-eighties-america-buying-spree-2013-1; http://www.japanintercultural.com/en/news/default.aspx?newsid=126.

[7] P.L. 100-418, Title V, § 5021, August 23, 1988; 50 U.S.C. app. § 2170.

[8] Executive Order 12661, December 27, 1988, 54 Fed. Reg. 779. Executive Order 12661 addressed numerous trade, tariff and other similar matters, and the provisions of Executive Order 12661 pertaining to CFIUS were incorporated into an amended version of Executive Order 11858.

data on foreign direct investment and occasionally advised the President on specific investments into a key component of business and foreign policy. Now, CFIUS was required to advise the President on foreign direct investments in the United States and it had the authority to investigate the potential impacts of such transactions and to recommend to the President that such transactions could be suspended, blocked or unwound.

The next revision to the CFIUS process occurred in 1992 with the passage of the "Byrd amendment," named for Senator Robert Byrd, which affirmatively required CFIUS to investigate proposed mergers, acquisitions or takeovers when (1) the acquirer is controlled by or acting on behalf of a foreign government; and (2) the acquisition results in control of a person engaged in interstate commerce in the United States that could affect the national security of the United States.[9] At this point, Congress had become increasingly concerned about the rise of sovereign wealth funds and other similar governmentally backed investors and their potential for carrying out foreign policy objectives through commercial means in a manner that could have adverse consequences for U.S. national security.

Several proposed transactions in the early to mid-2000s reignited interest in the potential impacts of foreign investment in the United States, particularly given the heightened sensitivity of Americans related to internal security and America's role in the world following the 9/11 attacks on the World Trade Center and the Pentagon. In 2005, the Chinese oil company CNOOC Ltd., which was 70% owned by the Chinese government, proposed to acquire the U.S. oil and gas company Unocal Corp. by substantially topping an acquisition proposal previously made by Chevron Corp. At that time, 70% of Unocal's oil and gas reserves were located in Asia while its U.S. reserves constituted approximately 1% of American oil consumption;[10] however, in this pre-fracking era, U.S. reserves were dwindling and concern was increasing about the rising economic might of Chinese companies backed by the Chinese government. Large segments of the American public as well as members of Congress focused their attention and concern on this potential transaction. Only two years previously, a company based in Hong Kong, Hutchison Whampoa Ltd. ("Hutchison Whampoa"), had abandoned a potential acquisition for the telecommunications carrier Global Crossing Ltd. ("Global Crossing") in the face of adverse publicity, Congressional concern and concerns raised by CFIUS when CFIUS initiated a 45-day investigation; after Hutchison Whampoa walked away, Global Crossing continued through its bankruptcy. Also in 2005, Dubai Ports World, a recently formed, and now leading, owner and operator of ports and transportation/supply terminals around the world, proposed to acquire all of the commercial port operations of the British-owned Peninsular and Oriental Steam Navigation Company ("P&O"), which included six ports located in the United States. The parties notified CFIUS of the proposed transaction and CFIUS undertook an investigation applying the less formal standards outlined in the Exon-Florio amendment. CFIUS completed its review in early 2006 and concluded that the transaction did not threaten to impair U.S.

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[9] Section 837(a) of the National Defense Authorization Act for Fiscal Year 1993, P.L. 102-484, October 23, 1992.

[10] *See* Leslie Wayne & David Barboza, "Unocal Deal: A Lot More Than Money Is at Issue," *N.Y. Times* (June 24, 2005).

national security, so CFIUS did not mandate a further 45-day formal investigation. Based on the CFIUS conclusions, Dubai Ports World acquired the P&O assets, including the six U.S. ports. This acquisition led to an immediate public outcry and significant criticism from a number of members of Congress, with much of the concern focusing around perceived security issues associated with control of key U.S. ports by an entity primarily owned and controlled by the Dubai government. Some members of Congress faulted CFIUS for failing to undertake a formal 45-day investigation, which they believed was mandated by the Byrd Amendment, and others criticized CFIUS for having an ill-defined, opaque review process that failed to properly prioritize national security and communicate with Congress regarding those risks. As a result of the outcry and criticism, Dubai Ports World voluntarily decided to sell the six U.S. ports to a U.S. owner, which it completed by the end of 2006. Meanwhile, Congress, after witnessing several high profile foreign acquisitions that resulted in intense public scrutiny, unfavorable press coverage and renewed concern about the role of foreign investors in the U.S. economy, decided to again revisit and revise the CFIUS process.

In 2007, Congress decided to tackle the issue of how to best balance the potentially competing desires of having an open economy that welcomes investment from all corners of the globe with protecting national security—and in this instance even struggling with the definition of national security in a globalized world where business, trade and economics were increasingly viewed as tools of national policy. The Senate and the House of Representatives introduced several CFIUS amendments[11] and began debating the issues of investment and national security. Congress eventually adopted the Foreign Investment and National Security Act of 2007 ("FINSA"), which was then signed into law by President Bush in 2007.[12] In early 2008, President Bush issued Executive Order 13456 to implement FINSA.[13] FINSA substantially modified and codified the CFIUS process, including by providing CFIUS with clear statutory authority and responsibilities, codifying the membership of CFIUS, and increasing the number of national security factors to consider in reviewing and analyzing foreign investment transactions. The Department of the Treasury adopted final regulations to comprehensively implement FINSA on November 21, 2008 ("FINSA Regulations").[14] Among other actions, the FINSA Regulations formalized the CFIUS national security review process, specified the types of detailed information that parties must include in notices of investment filed with CFIUS, required company officer certification of the information provided to CFIUS and provided penalties for material misstatements and omissions. The FINSA Regulations tried to improve clarity about the CFIUS process and to reflect actual business practices. In late 2008, the Department of the Treasury adopted formal guidance ("FINSA Guidance") to try to provide context to business and foreign investors with respect to the changes implemented by FINSA and the FINSA

[11] See, e.g., H.R. 556, the National Security Foreign Investment Reform and Strengthened Transparency Act of 2007, which was approved by the House by a vote of 423 to 0 and S. 1610, the Foreign Investment and National Security Act of 2007.

[12] P.L. 110-49, July 26, 2007.

[13] Executive Order 13456, January 23, 2008, which further amended Executive Order 11858.

[14] 31 C.F.R. Part 800, Regulations Pertaining to Mergers, Acquisitions and Takeovers by Foreign Persons, Final Rule, 73 Fed. Reg. 70702 (Nov. 21, 2008).

Regulations.[15] The FINSA Guidance focused on clarifying: (1) the purpose and nature of the CFIUS process, (2) the process for analyzing national security risk and illustrative examples of such risks, and (3) a narrative description of types of transactions that have previously presented national security issues of concern.[16] The FINSA Guidance opens by wrestling with the delicate balance of how to welcome investment in an open economy while protecting fundamental national security interests.[17] Given the competing interests at stake, there will always be a tug of war between these concepts, and prevailing attitudes will shift back and forth as to which should weigh more heavily: commerce or security. To further complicate the debate, defining what constitutes security will itself shift depending on where we focus.

For the last decade, FINSA has defined CFIUS and the CFIUS process. However, as with prior revisions and refinements, in the last couple years, recent world activity refocused scrutiny on the purposes and effect of the CFIUS process. Many Americans, and particularly policy-makers in Washington, D.C., have struggled with how to address the rising strength of multiple countries and economies around the world. China has stood at the center of this angst for a variety of reasons, including that its economy has grown explosively: it now has numerous companies that dominate or at least take a leading role in their industries, Chinese companies are viewed by many as state-supported tools of the government, the Chinese economy remains very hard to penetrate by non-Chinese companies and China has largely failed to rigorously enforce intellectual property rights held by non-Chinese entities. Additionally, foreign sovereign wealth funds and companies backed by direct or indirect foreign government support continue to vigorously compete for business and investments around the world, often with built-in advantages that Western-style public companies view as unfair. Many Americans are focusing more on the detriments of a globalized economy rather than the benefits, and fear that foreign companies have benefited from American liberal trade and economic policies while American companies have received little in return. Finally, with a decade of experience operating under the FINSA requirements, many companies have perhaps learned how to live within the technical confines of FINSA, while evading what many policy-makers would view as its intended spirit. In an FAQ about FIRRMA provided by the Department of the Treasury following its recent passage, Treasury stated: "Both the nature of foreign investments in the United States and the national security landscape have shifted significantly since [the Exon-Florio amendment and the passage of FINSA]."[18] Similarly, Congress, in the preamble, Sense of Congress findings for

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[15] 73 Fed. Reg. 74,567 (Dec. 8, 2008).

[16] *Id.*

[17] *Id.* The FINSA Guidance states:

> The United States has a longstanding commitment to welcoming foreign investment. In May 2007, the President's Statement on Open Economies reaffirmed that commitment, recognizing that "our prosperity and security are founded on our country's openness." CFIUS carries out its responsibilities within the context of this open investment policy. In the preamble to FINSA, Congress states that the purpose of the Act is "[t]o ensure national security while promoting foreign investment and the creation and maintenance of jobs [and] to reform the process by which such investments are examined for any effect they may have on national security."

[18] FIRRMA FAQs, https://www.treasury.gov/resource-center/international/Documents/FIRRMA-FAQs.pdf.

FIRRMA, noted that "the national security landscape has shifted in recent years, and so has the nature of the investments that pose the greatest potential risk to national security, which warrants an appropriate modernization of the processes and authorities of [CFIUS] . . . ."[19]

After wrestling with these policy and application concerns, Congress adopted FIRRMA, which was quickly signed by the President. While FIRRMA will control the CFIUS process in the future,[20] this paper's review and discussion of the application of FINSA will remain beneficial since many of the policies and procedures under FINSA, as updated by FIRRMA, will remain the same, and the types of issues and considerations involved in the CFIUS process under FINSA, as updated by FIRRMA, will remain the same.

B. CFIUS Process Under FINSA

The CFIUS process under FINSA features several notable aspects including that deciding whether or not to file a notice of a transaction with CFIUS is voluntary,[21] there are no *de minimis* dollar thresholds for a transaction that trigger a requirement to file and several of the terms that define when parties have crossed the CFIUS jurisdictional threshold are broad and open-ended, leaving some of its application uncertain and ambiguous. Furthermore, since all CFIUS proceedings and decisions remain confidential there is a paucity of guidance about how CFIUS works, particularly for practitioners that have never worked with it before or only occasionally encounter transactions that may trigger CFIUS.

As an interagency committee, CFIUS consists of multiple governmental agencies in an effort to provide a broad range of input and analysis on both the commercial and security aspects of proposed transactions. Rather than creating a separate new agency, CFIUS attempts to instead rely on the expertise and insights of its constituent members, each of which will bring a different focus and perspective. CFIUS currently consists of nine executive branch departments and offices: the Secretaries of State, the Treasury, Defense, Homeland Security, Commerce and Energy; the Attorney General; the United States Trade Representative; and the Director of the Office of Science and Technology Policy. The Secretary of Labor and the Director of National Intelligence serve as *ex officio* members. Additionally, five executive office members observe and participate as appropriate: the Director of the Office of Management and Budget; the Chairman of the Council of Economic Advisors; the Assistant to the President for National Security Affairs; the Assistant to the President for Economic Policy; and the Assistant to the President for Homeland Security and Counterterrorism. Finally, the President may appoint additional members on a temporary basis.[22] The

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[19] H.R. 5515, § 1702(b)(4).

[20] Portions of FIRRMA have immediate application, while others will become effective on the earlier of (i) 18 months following the date of enactment, or (ii) 30 days after publication in the *Federal Register* of a determination by the CFIUS chair that the regulations, structure, personnel, and resources are in place to implement the new provisions. H.R. 5515, § 1727.

[21] At least as an initial matter, the decision was voluntary, unless CFIUS decided to compel disclosure. Please note that one of the changes to be imposed by FIRRMA will be to make some types of filings with CFIUS mandatory.

[22] *See* Executive Order 11858, as amended by Executive Order 13456. Members of CFIUS consist of those agencies identified in the statute plus those added by the President by Executive Order plus those appointed by the President on a temporary basis from time to time.

Secretary of the Treasury serves as chair of CFIUS. In making decisions, CFIUS seeks to develop and obtain consensus from each of its constituent member agencies, each of which plays an equal role in the process.

1. CFIUS Application

CFIUS has a broad scope and mandate. As such, it is both simple and deceptively complicated, with many subtle nuances. As a general matter, CFIUS applies to all "covered transactions" (a "Covered Transaction"). As defined in the FINSA Regulations: "The term covered transaction means any transaction that is proposed or pending after August 23, 1988, by or with any foreign person that could result in foreign control of any U.S. business, including such a transaction carried out through a joint venture."[23] In order to understand the scope of CFIUS, one has to understand the meaning of each of the key words used in the definition of Covered Transaction. While this sentence seems simple, its application often leads to counterintuitive results, meaning that CFIUS will apply to transactions where the average business person would not see "control."

2. What Is a Foreign Person

CFIUS takes a broad view on what constitutes a "foreign person." In simple terms, the FINSA Regulations define a foreign person as "(a) [a]ny foreign national, foreign government, or foreign entity; or (b) [a]ny entity over which control is exercised or exercisable by a foreign national, foreign government, or foreign entity."[24] In determining whether a foreign person is involved, CFIUS looks through all levels and layers of entities to ascertain ultimate control. In other words, having a buyer that is a U.S. organization is not sufficient to avoid CFIUS if the ultimate owners of that U.S. buyer are themselves foreign persons. If a buyer has twenty separate organizational layers, starting with a U.S.-based entity that will actually make the acquisition, traveling through multiple layers of subsidiaries in multiple jurisdictions, and ending with several significant shareholders in a foreign entity, then CFIUS will pierce through, review and analyze each step and layer in its efforts to categorize any potential national security risk.

3. What Is a U.S. Business

The definition of what constitutes a U.S. business has been modified by FIRRMA. The FINSA Regulations used the following definition: "[t]he term U.S. business means any entity, irrespective of the nationality of the persons that control it, engaged in interstate commerce in the United States, but only to the extent of its activities in interstate commerce."[25] FIRRMA has simplified the definition, but that simplification is intended to expand the scope of coverage; however, the full extent of its impact will likely not be apparent except through the regulations issued by Treasury. FIRRMA simply states: "[t]he term 'United States Business' means a person engaged in interstate commerce in the United States."[26]

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[23] FINSA Regulations, 31 C.F.R. § 800.207.

[24] *Id.* § 800.216.

[25] *Id.* § 800.226.

[26] FIRRMA § 1703 (codified at 50 U.S.C. § 4565(a)(13)).

4. What Is Control

CFIUS imposes a functional test, rather than a specific numeric threshold, to determine "control." In other words, there are no bright line tests that clearly and definitively tell you when you have acquired control. Without inquiry, one could reasonably assume that "control" would require the acquisition of at least 51% of the voting interests of a company; however, for purposes of CFIUS, "control" could be found at ownership levels of less than 10% if other indicia of control are present.[27] According to the FINSA Regulations,

> [t]he term control means the power, direct or indirect, whether or not exercised, through the ownership of a majority or a dominant minority of the total outstanding voting interest in an entity, board representation, proxy voting, a special share, contractual arrangements, formal or informal arrangements to act in concert, or other means, to determine, direct, or decide important matters affecting an entity . . . .[28]

Determining the presence of control is in the eye of the beholder, after weighing all of the relevant facts.

While the definition of control is open to interpretation, the FINSA Regulations provide several examples of ordinary course transactions that do not constitute Covered Transactions, typically because they lack control. One of the common safe harbors to avoid the application of CFIUS occurs when a foreign party acquires 10% or less of voting interests of the U.S. business and the transaction is undertaken solely for the purpose of passive investment.[29] The FINSA Regulations detail several other transactions that would not be subject to

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[27] Other indicia of control will depend on the circumstances, and could depend on such factors as rights to appoint board members, rights to approve or terminate material contracts, rights to approve or veto company officers and rights to approve or veto new investments or lines of business. See the examples provided in 31 C.F.R. § 800.204.

[28] *Id.* § 800.204(a). This portion of the regulation goes on to list 10 specific factors that would indicate control

> in particular, but without limitation, to determine, direct, take, reach, or cause decisions regarding the following matters, or any other similarly important matters affecting an entity:
> (1) The sale, lease, mortgage, pledge, or other transfer of any of the tangible or intangible principal assets of the entity, whether or not in the ordinary course of business;
> (2) The reorganization, merger, or dissolution of the entity;
> (3) The closing, relocation, or substantial alteration of the production, operational, or research and development facilities of the entity;
> (4) Major expenditures or investments, issuances of equity or debt, or dividend payments by the entity, or approval of the operating budget of the entity;
> (5) The selection of new business lines or ventures that the entity will pursue;
> (6) The entry into, termination, or non-fulfillment by the entity of significant contracts;
> (7) The policies or procedures of the entity governing the treatment of non-public technical, financial, or other proprietary information of the entity;
> (8) The appointment or dismissal of officers or senior managers;
> (9) The appointment or dismissal of employees with access to sensitive technology or classified U.S. Government information; or
> (10) The amendment of the Articles of Incorporation, constituent agreement or other organizational documents of the entity with respect to the matters described in paragraphs (a)(1) through (9) of this section.

Section § 800.204(c) goes on to provide a list of typical minority shareholder protections that are not deemed, by themselves, to constitute control over an entity.

[29] *Id.* § 800.302(b).

CFIUS.[30] In another example, ordinary course lending and financing transactions, whether or not secured, do not, by themselves, constitute a Covered Transaction subject to CFIUS;[31] however, a subsequent default that could lead to foreclosure and control by a foreign lender would then become subject to CFIUS, and loans that include equity-like control features (such as the ability to appoint board members) may constitute a Covered Transaction.[32]

C. CFIUS Process

After parties make a determination that CFIUS applies to a particular transaction—does it involve (1) a foreign party that (2) acquires control of (3) a U.S. business—the parties need to decide whether or not to file a formal written notice of the transaction with CFIUS (a "Notice"), which would initiate a CFIUS review process. As noted earlier, except for certain mandatory declaration requirements under FIRRMA and its implementing regulations, filing with CFIUS is voluntary.[33] Parties must weigh the risks associated with both filing and not filing. In brief, by filing with CFIUS, the parties, assuming they eventually receive clearance, are then subject to a safe-harbor protection whereby the U.S. government may not then pursue the parties and unwind the transaction. If the parties fail to file with CFIUS, and CFIUS at any point in the future learns of the transaction and determines that the CFIUS jurisdictional hurdles had been met and that the transaction may raise national security issues, then CFIUS may require the parties to prepare and file a notice and submit to a CFIUS review.[34] At that point, the full powers remain available, meaning that the President could require the parties to unwind the transaction and divest the purchased interest. The downside to filing a Notice include the time and cost associated with this additional step. The parties need to carefully weigh numerous factors, particularly the nature of the U.S. business being acquired and the potential national security implications of the transaction, whether actual or perceptual, and make a business decision.

The CFIUS process itself consists of a series of discrete steps: (1) preparation of a formal written Notice to provide to CFIUS for review, (2) an informal initial review period by CFIUS, (3) submission of a final written notice to CFIUS, (4) a CFIUS national security review for a period of 45 days,[35] (5) a potential CFIUS national security investigation for a period of 45 days, (6) dialogue with CFIUS and response to any questions or requests for clarification from CFIUS during the 45-day review period and the 45-day investigation period, and (7) final action by

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[30] In addition to the acquisition of 10% or less of voting stock solely for passive investment purposes not creating a control transaction, the following would not constitute a Covered Transaction: (1) a stock split or stock dividend that does not involve a change of control, (2) an acquisition of an entity or assets that are not a U.S. business, (3) an acquisition of securities by a securities underwriter in the ordinary course, (4) an acquisition pursuant to an insurance contract relating to obligations contained therein made in the ordinary course, and (5) a change in the rights that a foreign person has with respect to a U.S. business in which that foreign person has an investment, if that change could not result in foreign control of the business. *See id.* § 800.302.

[31] *See id.* § 800.303.

[32] *Id.*

[33] *See id.* § 800.401(a) and the FINSA Guidance. Bear in mind that it is expected that FIRRMA will impose mandatory declarations with CFIUS for certain transactions.

[34] *Id.* § 800.401(b), (c).

[35] Please note that FIRRMA immediately placed into effect an increase in the initial review period to 45 days. Under FINSA, the review period had been 30 days.

CFIUS, which may consist of a finding of no unresolved national security issues (in which case the transaction may proceed to closing) or a recommendation to the President. If CFIUS makes a recommendation to the President, then the President has 15 days to act on that recommendation. The initial 45-day review period and the potentially subsequent 45-day investigation period may not be increased or extended by CFIUS.

Preparing a formal written Notice of a transaction to submit to CFIUS typically takes from a week to several weeks to collect the relevant information and then prepare the Notice, depending on the time and attention this project receives. Such Notices are typically prepared and submitted jointly by both the seller and the buyer, though the parties are not required to file jointly, and either party may decide whether or not to make a filing (subject to any language within the purchase and sale agreement that otherwise dictates the CFIUS process requirements). The Notice requires detailed information, which buyers and sellers may find to be intrusive and time consuming, particularly when they are more focused on their transaction. However, time and care taken in preparing the Notice will eventually save time by helping CFIUS to quickly understand the proposed transaction and the key issues and elements.[36] A poorly constructed Notice will lead to numerous questions and requests by CFIUS, and if the parties are unable to quickly provide responsive information, then CFIUS may essentially kick the Notice out of the review or investigation process, require the parties to revise and resubmit the Notice and re-start the 45-day initial review or the 45-day investigation process.[37]

Most CFIUS Notices closely track with each subsection of the FINSA Regulations detailing the required information.[38] Law firms that engage in a CFIUS practice will typically start with a form document that describes each of the FINSA Regulations requirements, though each filing will require detailed time and attention to properly track down the required information and then adequately and fully describing it in the Notice. A proper officer of each of the parties (seller and buyer) will need to certify as to the accuracy and completeness of the information contained within the Notice, and that certificate will be included in the filing made with CFIUS.[39] Parties that submit material misstatements or omissions in a Notice or that make false certifications may be subject to a civil penalty not to exceed $250,000 per violation.[40]

Once the seller and buyer have completed a Notice that they believe fully responds to the requirements of the FINSA Regulations, the parties then submit the Notice in draft form to CFIUS for an initial review, comments, questions, and reaction. This informal advance Notice also provides CFIUS with an opportunity to prepare for the filing, allocate appropriate staff resources, and prepare to

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[36] The FINSA Regulations state that the notice "shall provide in detail the information set out in this section, which must be accurate and complete with respect to all parties and to the transaction." *Id.* § 800.402(a).

[37] CFIUS may reject a Notice if the parties do not file responsive information to a request within 3 business days. *Id.* § 800.403(a)(3).

[38] *See id.* § 800.402.

[39] *Id.* § 800.402(*l*). According to the FINSA Regulations, an authorized officer is the chief executive officer or other duly authorized designee, such as another officer or director, or a general partner in the case of a partnership. *Id.* § 800.202.

[40] *Id.* § 800.801(a).

designate a lead agency for the review. This informal review period is enshrined in the FINSA Regulations and is well established as standard good practice.[41] Providing CFIUS with five business days to review and comment on the draft notice is typical practice, though if CFIUS is particularly busy, parties may be informally requested to allow for additional time prior to filing the final notice.[42] Parties should expect during this initial period of time that CFIUS will have questions and requests, which should be addressed and reflected in the final Notice prior to formal filing.

After CFIUS has received a paper copy of the complete Notice, the 45-day review period commences on the first business day following the date on which the Staff Chairperson has determined that the Notice complies with FINSA Regulations § 800.402 and has provided copies of it to all CFIUS members.[43] Unlike the HSR Act, which allows the parties to request early termination of any review, the parties submitting a Notice should prepare to wait the full 45 days for a determination, as the authors are not aware of any review being completed prior to the expiration of the full initial review period (which had been 30 days under the FINSA Regulations, but has now increased to 45 days pursuant to FIRRMA). During the 45-day review period, each of the CFIUS constituent agencies will read and analyze all of the information contained within a Notice and assess potential risks, and the Director of National Intelligence will undertake a comprehensive threat analysis to identify and quantify any potential threats to U.S. national security that could result from the proposed transaction.

Following completion of the 45-day review period, CFIUS may request a further 45-day investigation period if it believes that there are unresolved potential national security issues that require further analysis. A 45-day investigation is required if the initial review identifies at least one trigger: (1) CFIUS believes that the transaction threatens to impair national security and that threat has not been mitigated, (2) the foreign person buyer is a foreign person controlled by a foreign government (which can mean anything from a sovereign wealth fund to a government owned corporation to a publicly owned corporation that may be controlled by a foreign government), or (3) the transaction would result in control by the foreign person of critical infrastructure, the transaction could impair national security and that threat has not been mitigated.[44] As with the initial 45-day review period, the 45-day investigation period may not be extended.

During the course of either the 45-day review period or the 45-day investigation period, CFIUS may reject a filed Notice if (1) a material change occurs in the transaction described in the Notice, (2) CFIUS discovers information

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[41] *Id.* § 800.401(f) states:

> Parties to a transaction are encouraged to consult with the Committee in advance of filing a notice and, in appropriate cases, to file with the Committee a draft notice or other appropriate documents to aid the Committee's understanding of the transaction and to provide an opportunity for the Committee to request additional information to be included in the notice. Any such pre-notice consultation should take place, or any draft notice should be provided, at least five business days before the filing of a voluntary notice.

[42] Please note that FIRRMA will increase the informal review period to 10 business days. Since the FINSA informal period is expected, but not mandatory, it is anticipated that CFIUS will require 10 business days for their informal review immediately.

[43] *Id.* § 800.502.

[44] *Id.* § 800.503.

that contradicts material information provided in the Notice, or (3) the parties to a Notice fail to provide adequate follow-up information requested by CFIUS within three business days of the request.[45] If CFIUS rejects a Notice, the parties will have an opportunity to revise their Notice to address the changes, inconsistencies or requested information and re-submit the revised Notice, at which time a new 45-day review period will begin anew.

At the end of the 45-day review period, CFIUS may either initiate a 45-day investigation or conclude action under section 721 of FINSA.[46] If CFIUS concludes action, then the transaction has received CFIUS clearance and the parties may proceed to close their transaction. If a 45-day investigation is initiated, then CFIUS shall complete the investigation no later than 45 days after its commencement; however, the investigation period may be extended for one period of 15 days in extraordinary circumstances.[47] This investigation may then result either in CFIUS concluding action under section 721 of FINSA without sending a report to the President, at which time the parties may proceed to closing, or in CFIUS sending a report to the President requesting a Presidential decision, which typically would include either suspending or prohibiting the proposed transaction.[48] Under FINSA, only the President may suspend or prohibit a proposed transaction; CFIUS does not have the authority to take such action by itself. Similarly, CFIUS does not technically "approve" or "consent" to a transaction; they simply conclude action without making a recommendation to the President. Meanwhile, the President has no obligation to accept any recommendation made by CFIUS. Even if CFIUS were to recommend that the President block a particular transaction, the President may ignore that recommendation and allow the parties to proceed with their transaction. In practice, the President follows the recommendations made by CFIUS, and in fact, there are only a handful of matters notified to CFIUS that have ever made it as far as a report to the President. Generally, prior to the completion of an investigation and a CFIUS recommendation against a transaction, CFIUS will have clearly communicated their national security concerns to the parties involved and the parties will withdraw their notice and halt their proposed transaction rather than suffer the negative publicity consequences of a Presidential determination to block a transaction. Thus, when public announcements are made that parties have withdrawn their CFIUS Notice and have abandoned their proposed transaction, more often than not, CFIUS identified national security concerns that could not be resolved.

FINSA articulates 11 specific national security factors that the President (and thus CFIUS) must consider when analyzing a proposed transaction.[49] While many of these factors highlight industries that one would assume would be of interest when analyzing the security and defense of the United States, such as those related to domestic capabilities to provide national defense and military requirements and

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[45] *Id.* § 800.403.

[46] *Id.* § 800.504.

[47] *Id.* § 800.506(e). Extraordinary circumstances are defined in *id.* § 800.506(f) to mean "circumstances for which extending an investigation is necessary and the appropriate course of action due to a force majeure event or to protect the national security of the United States."

[48] *Id.* § 800.506.

[49] *See* FINSA § 721(f).

critical technologies,[50] two factors specifically implicate oil, gas, mining, and energy industries. First, CFIUS must take into account "the potential national security-related effects on United States critical infrastructure, including major energy assets."[51] Second, CFIUS must consider "the long-term projection of United States requirements for sources of energy and other critical resources and material."[52] Thus, CFIUS considers natural resources to constitute vital national security interests, and as a result, natural resources lawyers need to be aware that transactions involving natural resources may be of interest to CFIUS.

FINSA contemplates that certain transactions may be allowable if the parties agree to manage or mitigate the potential national security risks as a condition to receiving CFIUS clearance and proceeding with their transaction.[53] The government could then monitor and enforce these mitigation agreements to try to control the perceived national security risks. Since mitigation agreements remain confidential, it is difficult to have a good sense of how often CFIUS requires such agreements and what they cover. However, examples could include requirements to spin off and divest particular assets or pieces of an acquired business that are deemed to be particularly sensitive; commitments to maintain production and personnel in the United States; covenants that prohibit certain foreign persons from participating in the business and operations of the acquired entity; prohibitions or limitations on the export of technology; and covenants to keep particular lines of business or decision-making walled off from the foreign buyer in a manner that maintains security.

CFIUS has received increasing press attention in the last year, as America and its policy makers have increasingly focused on the potential adverse effects of foreign investment, so an increasing number of companies, lawyers and business people have a greater awareness of it as a potential issue in purchase and sale transactions. With slightly over a decade of experience with FINSA, many deal lawyers have developed at least a general working knowledge of the statute and its requirements. Nonetheless, the details of the CFIUS process remain a mystery to many, which has resulted from a number of factors including the opacity of the process and an uninformed belief that it only applies to takeover transactions for military contractors and other similar sectors of the economy. By better understanding the broad scope of CFIUS, lawyers working on a transaction can better anticipate potential roadblocks and advise their clients on how to proceed.

Parties to a transaction must weigh multiple competing factors in deciding whether or not to file a Notice with CFIUS. As noted above, that determination is voluntary (for now).[54] The answer to this question is rarely simple or straightforward. It requires wading through and weighing a complex mix of legal, business, public relations and practical issues. To begin the analysis, the parties must seriously consider what types of national security considerations (in their broadest sense) are implicated by the transaction, and whether the parties are willing to accept the risk of having CFIUS decide at a later date to review an already completed transaction, and potentially impose a mitigation plan or require

[50] *See id.* § 721(f)(1), (2), (5), (7).

[51] *Id.* § 721(f)(6).

[52] *Id.* § 721(f)(10).

[53] *See id.* § 721(*l*).

[54] FIRRMA is expected to make some filings mandatory once regulations are adopted.

the divestment of assets. CFIUS identifies an actionable national security risk based on an analysis of the intersection between threat and vulnerability and the resulting potential adverse consequences[55]—whether the foreign person has the capability or intention to exploit or cause harm and there is a weakness or shortcoming that could lead to an impairment of national security.

In addition to the legal analysis outlined in this paper, other factors to consider (of which there are many, and these are only a few) should include: (1) are there rival U.S. bidders that would not have to file with CFIUS; (2) are there rival U.S. bidders that would complain to Congress or assert in friendly press coverage that foreign ownership raises national security considerations and must be investigated; (3) will the transaction result in significant press coverage on its own, raising the likelihood that CFIUS would become aware of the transaction, either before or after closing, or resulting in adverse publicity if the parties decide not to file with CFIUS; (4) does the foreign buyer want to be perceived by the U.S. government as a good actor that is not trying to avoid or evade a U.S. regulatory scheme; (5) will CFIUS clearance be required by a foreign bidder as a condition to its financing (particularly if such financing is governmental financing) or to transfer funds out of its home country; (6) does the foreign buyer expect to make numerous control acquisitions in the United States and want to establish a good relationship with CFIUS and the U.S. government; and (7) will other governmental authorizations be required, such as Hart-Scott-Rodino or Federal Communications Commission approvals, all of which may lead to questions from the government about CFIUS.

Additional positive factors associated with filing with CFIUS include: (1) completing the CFIUS process eliminates the possibility that CFIUS will block closing or unwind the transaction at a later date; (2) by initiating a filing, rather than responding to a CFIUS demand, the parties can better control the process, the messaging and the dialogue with CFIUS; and (3) CFIUS clearance may make it easier to obtain other necessary regulatory approvals, both within the United States and in the buyer's country of origin. Negative factors to consider include: (1) preparing and filing a Notice and completing the CFIUS review process takes time and money—it adds to the time required to get to a closing and it increases the cost of the transaction; (2) requiring a CFIUS Notice may put a foreign bidder at a disadvantage, including through the perception that it decreases the certainty of closing; (3) obtaining CFIUS clearance may require a mitigation agreement, governmentally mandated conditions to the future operations of the assets or orders to divest potentially meaningful assets or aspects of the business; (4) submitting to the CFIUS process may attract unwanted attention; (5) sellers may require a premium to the purchase price to compensate them for the increased risk and uncertainty; (6) a Notice requires detailed disclosure about the ownership and intentions of the buyer, which may include highly sensitive details that the buyer may be reluctant to disclose (notwithstanding the confidential nature of the CFIUS process); and (7) following the adoption of FIRRMA implementing regulations, CFIUS will be allowed to assess and collect a filing fee.

The Department of the Treasury prepares and provides a report to Congress each year summarizing information about the cases considered by CFIUS.[56] The

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[55] CFIUS Guidelines, 73 Fed. Reg. 74567, 74569, Dec. 8, 2008.

[56] *See* https://www.treasury.gov/resource-center/international/foreign-investment/Pages/cfius-reports.aspx for links to each annual report.

most recent report covers 2015. Since all CFIUS cases are confidential, these reports provide aggregated information, rather than case-specific information, which can be helpful to identify trends and issues of concern. For 2015, CFIUS undertook a review of 143 transactions and launched subsequent national security investigations on 66 of those transactions. Eleven of the 143 transactions required the implementation of mitigation agreements as a condition of clearance. Thirteen of the 143 transactions were withdrawn by the parties prior to the completion of CFIUS action, meaning that there were unresolvable national security issues (other than one abandoned for commercial reasons), though 9 of the withdrawn 13 subsequently re-filed new Notices after addressing the national security concerns. One of the 143 transactions was rejected.[57] For the period 2009 through 2015, 770 transactions were notified to CFIUS, with 310 of those transactions requiring national security investigations.[58] During this period, 18% of the transactions (or 137) were in the Mining, Utilities and Construction sector (a categorization that includes oil and gas).[59] The annual report provides information about the country of origin of the foreign buyer. In 2015, the top five countries filing Notices were: China (29); Canada (22); United Kingdom (19); Japan (12); and France (8).[60]

D. Changes Imposed by FIRRMA

FIRRMA expands the scope of covered transactions and is intended to further modernize and formalize CFIUS's processes. Overall, FIRRMA attempts to fill several perceived gaps in the coverage of FINSA to ensure that CFIUS has the clear and appropriate authority to oversee and regulate certain types of transactions that could result in national security issues but may not be clearly within the parameters of FINSA. FIRRMA allows CFIUS to more clearly focus on functional factors associated with control rather than primarily the numeric percentage ownership of securities or other organizational control rights. The full impact of FIRRMA will become more apparent when reviewed in conjunction with its implementing regulations, some of which already have been promulgated. Many provisions of FIRRMA refer generally to the new area of focus, but then defer the details to the regulations. One immediate impact of FIRRMA is to increase what had been a 30-day national security review period into a 45-day period. Following the adoption of implementing regulations, the 45-day national security investigation period may be extended for an additional 15-day period under extraordinary circumstances. Several other FIRRMA provisions, such as several of the definitions, have immediate effectiveness.

FIRRMA adds four specific new types of covered transactions, each of which will require further detail and specification in the forthcoming regulations: (1) a purchase, lease or concession of real estate located in proximity to military bases or other sensitive government facilities; (2) "other investments" in certain U.S. business that afford a foreign person access to material nonpublic technical information, personal information or genetic information; membership on the board of directors; or other decision-making rights, other than through voting of shares; (3) any change in a foreign investor's rights resulting in control of a U.S.

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[57] *See* CFIUS Annual Report to Congress, Report Period CY: 2015, Public/Unclassified Version.

[58] *Id.* at 3.

[59] *Id.* at 4.

[60] *Id.* at 16–17.

business (such as a bankruptcy or loan default leading to foreclosure); and (4) any other transaction, transfer, agreement or arrangement designed to circumvent CFIUS jurisdiction.

FIRRMA established additional factors for CFIUS to consider in its review of transactions, including whether the proposed acquirer is a country or entity of special concern; potential national security implications of cumulative control by a foreign person in a particular critical infrastructure, energy asset, critical material, or critical technology; whether the foreign investor has a history of compliance, or conversely, a history of non-compliance; whether foreign control of an asset affects the ability of the United States to meet national security requirements; whether the transaction exposes personally identifiable information or sensitive data of U.S. persons to access by foreign governments; and whether the transaction creates or exacerbates cybersecurity vulnerability. These additional factors accentuate the expanded scope of CFIUS under FIRRMA to consider specific concerns related to particular countries or entities, the impacts on consolidation in certain industries, and an increasing focus on emerging areas of concern such as data privacy and cybersecurity.

The Department of the Treasury issued the first implementing regulations under FIRRMA on October 11, 2018 (the "Pilot Program Regulations").[61] The Pilot Program Regulations became effective November 10, 2018. The Pilot Program Regulations primarily relate to Pilot Program U.S. Businesses, which are defined as "any U.S. business that produces, designs, tests, manufactures, fabricates, or develops a critical technology that is: (a) [u]tilized in connection with the U.S. business's activity in one or more pilot program industries; or (b) [d]esignated by the U.S. business specifically for use in one or more pilot program industries."[62] Any determination as to what constitutes a Pilot Program U.S. Business rests on two key definitions: critical technologies and pilot program industries. Critical technologies include defense articles or services included on the U.S. Munitions List; items included on the Commerce Control List; specially designed and prepared nuclear parts, components, and software; nuclear facilities, equipment, and materials; certain chemical agents and toxins; and emerging and foundational technologies controlled pursuant to the Export Control Act.[63] The Pilot Program Regulations designate by the North American Industrial Code System 27 specific industries as pilot program industries.[64] For practitioners conducting due diligence on a potential transaction, many of the designated pilot program industries could include transactions involving natural resources.

As with other aspects of CFIUS, a determination of what constitutes a Pilot Program U.S. Business appears to be deceptively narrow. However, a more careful review of the key components of a Pilot Program U.S. Business indicates that its ambit is much broader. An indicative example relates to nuclear power generation. At first glance, nuclear power generation would appear to relate only to an actual power plant that generates electricity. A careful analysis of the definition of critical technologies, however, indicates that the scope of nuclear power generation is much broader. Critical technologies include items included on the

[61] 83 Fed. Reg. 51,322 (Oct. 11, 2018).

[62] 31 C.F.R. § 801.213.

[63] *Id.* § 801.204.

[64] *Id.* § 801 app. A.

Commerce Control List. If, for example, refined uranium products or semi-refined uranium products (such as yellowcake) appear on the Commerce Control List, then the mining and milling of uranium could constitute a critical technology subject to the Pilot Program Regulations.

As with nuclear power generation, many of the pilot program designated industries could implicate what initially appears to be a straightforward natural resources transaction. A natural resources practitioner conducting due diligence on a transaction, therefore, needs to understand the full nature of business subject to the transaction and where that business fits in the value chain in order to determine the applicability of the Pilot Program Regulations to the transaction.

In addition to Pilot Program U.S. Businesses, the Pilot Program Regulations establish mandatory declaration requirements for certain investments that may result in access to material nonpublic information in the possession of a Pilot Program U.S. Business; membership or observer rights in respect of a Pilot Program U.S. Business; or involvement, other than through the voting of shares, in substantive decision-making of the Pilot Program U.S. Business regarding the use, development, acquisition, or release of critical technology. The inclusion of these factors related to investment serve to highlight the expanded scope of CFIUS under FIRRMA to review secondary rights in investments that otherwise would not fall within the definition of control. Indirect investments by a foreign person through an investment fund that affords the foreign investor membership as a limited partner (or equivalent) on an advisory board or committee is not considered a pilot program covered transaction, provided that the fund is managed exclusively by a general partner (or equivalent) that is not the foreign limited partner (or equivalent); the advisory board or committee does not have the authority to approve or disapprove or control investment decisions of the fund or decisions by the general partner (or equivalent) regarding the portfolio assets of the fund; the foreign limited partner (or equivalent) cannot otherwise control the fund; the foreign limited partner (or equivalent) does not have access to material nonpublic technical information as a result of its participation on the advisory board or committee; and the investment otherwise meets the requirements for the transaction not to be covered by FIRRMA. This limited exception to the mandatory declaration requirements requires careful evaluation during the due diligence process in order to understand the structure of investment funds making investments into U.S. businesses, even if the investment fund does not appear to have control over the U.S. business.

The Pilot Program Regulations establish mandatory declaration requirements with CFIUS for transactions that could result in organizational or functional control of a Pilot Program U.S. Business.[65] This is a significant departure from the voluntary filing structure under FINSA and its predecessor regulations. A mandatory declaration must be made not less than 45 days prior to the anticipated closing date for the transaction. CFIUS then has 30 days to review the mandatory declaration; however, the 30-day review period does not begin until the CFIUS chair transmits the declaration to the other CFIUS members. Declarations are to be filed electronically.[66] The content of a declaration is specified in the Pilot Program

[65] *Id.* § 801.401.

[66] *Id.* § 801.402.

Regulations.[67] Significant penalties apply for failure to file a mandatory declaration, up to the value of the transaction.[68] Even if a mandatory declaration is not required under the Pilot Program Regulations, an analysis should be undertaken to determine whether a voluntary filing is advisable under other applicable CFIUS regulations.

Mitigation agreements will become more prominent and institutionalized under FIRRMA.

While CFIUS has traditionally been voluntary, FIRRMA will for the first time mandate the filing of Notices for transactions in which a "foreign person in which a foreign government has, directly or indirectly, a substantial interest" acquires a substantial interest in a critical technology or critical infrastructure company, or a company that handles large amounts of sensitive personal data. The specific structure of this new mandate will not be known until regulations are adopted.

Due to the expanded scope of CFIUS under FIRRMA and an expectation of a continuing increase in the number and complexity of transactions notified to CFIUS, FIRRMA grants special hiring authority for CFIUS, provides specific funding for CFIUS, and provides for filing fees to be assessed by CFIUS.

E. Due Diligence Considerations

CFIUS is one of a few topics that requires due diligence on both parties to a purchase and sale transaction. First, due diligence on both the seller and the buyer is required in order to ascertain all of the relevant facts detailed in the CFIUS Notice, including the ultimate ownership of the buyer, in order to determine if CFIUS applies. Second, if CFIUS applies, the parties need to review the operative facts, the law and the political and practical factors that may apply in order to determine if a voluntary CFIUS filing will be made. This due diligence will then play a key role in drafting the purchase and sale agreement, since many such agreements now contain definitions, representations, and covenants relating to CFIUS, the CFIUS factors and completing the CFIUS process. Parties need to understand the facts as identified in the due diligence process to ascertain if the purchase and sale agreement provisions are appropriate, or must be modified.

Much of the due diligence about the seller will have been developed and made available as part of the purchase and sale process, though the parties will need to review the specific categories required in a Notice in order to answer questions that may not have been included in a data room or otherwise immediately available. The parties need to consider if additional diligence is required to prepare an accurate and complete Notice, and the seller and buyer then need to work on responding to the CFIUS Notice requirements in a manner that is clear, concise and provides the details that CFIUS will need in order to make a determination. More information, rather than less, is typically preferred by CFIUS so that they adequately understand the transaction and its impacts, and they trust that the parties are being forthcoming in their disclosure.

Buyers new to CFIUS will be surprised at the level of diligence required by CFIUS in order to fully understand buyer's ownership, both to determine if the buyer is a "foreign person" and to then accurately and completely describe the buyer and its ownership in a Notice. Many buyers will view this as highly

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[67] *Id.* § 801.403.

[68] *Id.* § 801.409.

invasive, particularly when due diligence has traditionally focused primarily, if not solely, on the seller and the seller's business and assets.

If the buyer meets the "foreign person" test and the parties determine that they will prepare and file a CFIUS Notice, a savvy seller will undertake further due diligence on the buyer to help the seller to better anticipate CFIUS questions and concerns and therefore understand and categorize the risk of obtaining CFIUS clearance and getting to a closing. At this point in the transaction, a seller should appropriately think about inquiring about the following topics: (1) what is the nature and extent of the buyer's current business and ownership of assets in the United States; (2) what is the nature of the buyer's ownership (beyond its foreign country of organization, does it have controlling shareholders (as control is defined by CFIUS); and if so, where are those shareholders located); (3) what ties does the buyer have to foreign governments, whether formal or informal, direct or indirect; (4) has the buyer ever previously filed a Notice with CFIUS, whether in connection with an existing U.S. business or otherwise; (5) if so, how many of those Notices were cleared, subject to investigation beyond the initial review, or voluntarily withdrawn; (6) is the buyer currently, or has the buyer previously, been subject to a mitigation agreement or other similar arrangement with CFIUS as a condition to clearance; and (7) if so, what were the terms and conditions of that mitigation (while the details may be confidential, a seller should know the general nature of the national security concerns and how they were resolved).

Due diligence, of both the seller and the buyer, will aid the CFIUS process and allow the lawyers to anticipate potential issues and questions, both for the purpose of advising their clients and for the purpose of preparing the Notice and working the Notice through the CFIUS process.

F. Prior Problematic Transactions

As noted above in the CFIUS 2015 Annual Report, the vast majority of transactions notified to CFIUS receive clearance to close. Thus, it would appear that CFIUS attempts to make an informed balance between promoting commerce and guarding national security, and that transactions will only meet resistance when actual national security concerns exist. In order to better understand when problems may arise, this section will summarize a few transactions that have encountered problems, thus highlighting some of the potential pitfalls of what may initially appear on their face to be ordinary course transactions. Due to the confidentiality of the CFIUS process, it can be difficult to learn about proposed transactions that have encountered problems with CFIUS; typically, this only becomes known if the transactions receive press coverage or the parties to the transaction voluntarily disclose the circumstances.

Firstgold Corp.

In 2009, a Chinese company, Northwest Nonferrous International Investment Corp. ("Northwest") proposed to make a substantial investment in a financially struggling mining company, Firstgold Corp. ("Firstgold"), that owned precious metals exploration and development properties in Pershing County and Churchill County, Nevada, with its primary asset being the Relief Canyon Mine, located 95

miles northeast of Reno.[69] The Relief Canyon Mine had been operated intermittently by Pegasus Gold Corporation prior to its bankruptcy, but it was now on a care and maintenance status, with Firstgold undertaking activities to try to re-open the mine. Northwest had proposed to (1) buy the existing senior secured debt of Firstgold, (2) extend an additional loan of $5 million to Firstgold, and (3) acquire 51% of the shares of Firstgold. The parties submitted a Notice to CFIUS, which was subject to a national security review and then a further national security investigation. Prior to the end of the 45-day investigation period, CFIUS made it clearly known to the parties that there were unresolvable national security issues, since the Firstgold properties were located near the Fallon Naval Air Base, where the U.S. military trains pilots and tests new aircraft, and other sensitive governmental properties.[70] Northwest chose to terminate the proposed transaction and withdraw its Notice, rather than waiting for the President to reject the transaction. Prior to this transaction and the national security concerns raised by CFIUS, it had not been apparent that proximity was a national security factor, since it is not mentioned in either FINSA or the FINSA Regulations. While CFIUS has treated proximity as a national security factor since Firstgold, one of the stated purposes of FIRRMA was to close this gap and specifically address proximity to military and other sensitive sites.

Lincoln Mining Corporation

Lincoln Mining Corporation ("Lincoln"), a Canadian mining company, owned certain early-stage precious metals exploration properties in Churchill and Lyon Counties, Nevada, including one property near Tonopah, Nevada, not far from Fallon Naval Air Base. In 2012, Procon Mining and Tunneling Ltd., ultimately an affiliate of China National Machinery Industry Corporation (collectively, "Procon"), a Chinese state-owned company, made an investment in Lincoln consisting of equity and a convertible debenture, without first submitting it to CFIUS for review. After learning of the transaction, CFIUS approached Lincoln and Procon to discuss the matter, and as a result, Lincoln and Procon voluntarily prepared and submitted a Notice. In 2013, after learning that CFIUS had serious national security concerns resulting from its investigation, Lincoln and Procon chose to jointly withdraw their Notice and entered into a binding commitment with CFIUS whereby Procon was required to divest its entire equity and debt investment in Lincoln within 120 days; furthermore, the equity and debt could only be sold to one or more entities approved by CFIUS. Until the divestment was complete, Lincoln was significantly restricted from accessing or using its exploration properties.[71]

Ralls Corp.

In March 2012, Ralls Corporation ("Ralls"), a Delaware corporation, purchased four prospective wind-farm properties, consisting of certain land rights to construct wind farms and other related assets, via the acquisition of four

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[69] One of the authors of this paper and his law firm represented one of the parties in this matter, though the information contained in this paper is based solely on publicly available information.

[70] https://www.nytimes.com/interactive/projects/documents/memo-regarding-the-sale-of-firstgold-corp; https://www.nytimes.com/2009/12/22/business/global/22invest.html.

[71] *See* Lincoln press release dated June 18, 2013, at http://www.lincolnmining.com/news/archive/index.php?content_id=255.

separate limited liability companies (the "Wind Companies") that were ultimately owned by a wind-energy company based in Greece, Terna Energy SA ("Terna"). The parties completed their transaction without first submitting it for CFIUS review. The wind properties were located in Oregon along the Columbia River. On its face, without inquiry, this would appear to be the opposite of a fact pattern subject to CFIUS since the buyer was a U.S.-incorporated entity and the seller was ultimately foreign owned. However, the U.S. buyer Ralls was ultimately owned by two Chinese nationals.

In June 2012, after learning of the transaction, CFIUS approached Ralls and Terna, and as a result, the parties filed a Notice describing their transaction. During its national security review and investigation, CFIUS determined that the acquisition of the Wind Companies posed unresolvable national security threats resulting from the proximity of the wind farms to a Naval Weapons Systems Training Facility and its restricted airspace, where the U.S. military tested drones and other military aircraft. On July 25, 2012, prior to completing its review and making its national security risk determination, CFIUS issued an Order Establishing Interim Mitigation Measures ("Interim Order") to mitigate the imminent national security threats during the pendency of the CFIUS investigation. This Interim Order required Ralls to (1) cease all construction and activities at the project sites; (2) remove all stockpiled or stored items at the sites and not add anything else; and (3) cease all site access. On August 2, 2012, CFIUS issued an Amended Order Establishing Interim Mitigation Measures, which imposed the following additional restrictions: (1) Ralls was prohibited from selling the Wind Companies or assets without first removing all items placed there, including the concrete foundations; (2) Ralls was required to notify CFIUS of any proposed sale; and (3) Ralls was required to give CFIUS 10 business days to object to any proposed sale. While CFIUS identified unresolvable national security issues, the parties chose not to withdraw their completed transaction. As a result, CFIUS referred the matter to the President with a recommendation that the President unwind the transaction. On September 28, 2012, President Obama issued an executive order stating that the transaction threatened to impair U.S. national security and requiring Ralls to divest itself of the Wind Companies.[72]

Ralls is particularly notable for the fact that the parties, instead of accepting the Presidential determination, decided to challenge the decision by litigating in federal court. This case resulted in both district court and appeals court decisions resulting in a wealth of information about CFIUS and the CFIUS process that had previously not been widely available due to the confidentiality of CFIUS proceedings.[73] While the Ralls case articulated certain due process rights applicable to a CFIUS proceeding, the Presidential decision to block the transaction and cause the parties to unwind it remained in place.

Aixtron

President Obama blocked a second transaction using the authority granted to CFIUS in connection with a proposed acquisition of Aixtron SE ("Aixtron"), a

[72] Order Signed by the President Regarding the Acquisition of Four U.S. Wind Farm Project Companies by Ralls Corporation, The White House, September 28, 2012.

[73] *See* Ralls Corp. v. CFIUS, 758 F.3d 296 (D.C. Cir. 2014); Ralls Corp. v. CFIUS, 926 F. Supp. 2d 71 (D.D.C. 2013); *see also* Judy Wang, "*Ralls Corp. v. CFIUS*: A New Look at Foreign Direct Investments to the US," 54 *Colum. J. Transnat'l L.* 30 (2016).

German semiconductor company with approximately 20% of its assets and sales in the United States, by Grand Chip Investment GmbH, a German subsidiary of Fujian Grand Chip Investment Fund LP owned 51% by a Chinese businessman/investor and 49% by Xiamen Bohao Investment Ltd., an investment fund owned by two Chinese private investors.[74] Although the vast majority of the Aixtron business and assets existed outside the United States, the small 20% portion located within the United States was sufficient for CFIUS to assert jurisdiction. The national security concerns appear to be related to the military applications associated with Aixtron's proprietary semiconductor technology, including in the Patriot missile system.[75] In response to the failed transaction, Aixtron announced that it would need to restructure and likely lay off employees.

Lattice Semiconductor

In 2017, Canyon Bridge Capital Partners LLC ("Canyon Bridge"), a Silicon Valley-based private equity fund, pursued a transaction to acquire Lattice Semiconductor Corp. ("Lattice"), a maker of programmable logic chips with application in telecommunications, industrial and military industries that generated more than 70% of its revenue in Asia. As it turns out, Canyon Bridge has significant financial backing from Chinese limited partners, including a Chinese state-owned asset manager. Following a CFIUS review and investigation, CFIUS recommended to the President that he block the transaction.[76] While most companies will abandon their transaction when they learn that CFIUS will make a recommendation to block it, Canyon Bridge and Lattice instead took the unusual approach of appealing to the President and offering substantial mitigation measures, all in an effort to lobby for a Presidential rejection of the CFIUS recommendation. On September 13, 2017, President Trump accepted the CFIUS recommendation and blocked the Canyon Bridge/Lattice transaction.[77]

Qualcomm-Broadcom

President Trump, acting under the auspices of CFIUS, blocked a second proposed transaction in 2018, when he blocked the proposed acquisition of Qualcomm Inc. ("Qualcomm") by the Singapore-based Broadcom Ltd. ("Broadcom").[78] This investment, at $117 billion, would have been the largest technology-related foreign investment to date. Broadcom had previously prepared to try to address national security issues by moving its headquarters to the United States and offering substantial mitigation measures. The national security concerns appeared to relate to sensitive work for the United States done by Qualcomm and a concern about maintaining U.S. supremacy in new technologies, particularly the

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[74] http://www.semiconductor-today.com/news_items/2016/dec/aixtron_091216.shtml.

[75] Guy Chazan, "Fujian Drops Aiztron Offer After US Blocks Deal," *Fin. Times* (Dec. 8, 2016).

[76] "Trump Just Blocked a Chinese Takeover of a Sensitive U.S. Company: Here's What's Going On," *Wash. Post* (Sept. 19, 2017).

[77] https://www.bloomberg.com/news/articles/2017-09-13/trump-blocks-china-backed-bid-for-chip maker-over-security-risk; https://qz.com/1077213/trump-has-stopped-an-acquisition-of-lattice-semi conductor-by-canyon-bridge-a-private-equity-fund-with-ties-to-chinese-state-run-firms/.

[78] "Trump Blocks Broadcom Deal," *Wall St. J.* (Mar. 13, 2018), at A-1.

5G next generation of wireless technology.[79] The United States may also have had concerns about wanting to maintain a strong U.S. competitor to the Chinese company Huawei Technologies Co.[80] Broadcom was pursuing a hostile takeover of Qualcomm, and Qualcomm was aggressively pursuing a number of actions to thwart the proposed takeover. According to reports, Qualcomm unilaterally informed CFIUS of the transaction, as opposed to making the more typical joint voluntary Notice, in an effort to frame its national security concerns with the U.S. government on its own terms, as one of its efforts to derail the proposed takeover.[81] In the meantime, Broadcom was pursuing many efforts to complete the transaction, including proposing numerous new Qualcomm board members for election in an effort to stack the board with directors that would support the acquisition. In addition to blocking the transaction, the Presidential order also prohibited the election of the board members proposed by Broadcom.

III. Hart-Scott-Rodino

The Hart-Scott-Rodino Antitrust Improvements Acts of 1976, as amended ("HSR Act"), generally requires that each party to an acquisition of voting securities, controlling interests in a non-corporate entity (such as a limited liability company or partnership) and/or assets file a premerger Notification and Report Form ("Form") with both the U.S. Federal Trade Commission ("FTC") and the U.S. Department of Justice ("DOJ"), if the value of such acquisition meets or exceeds certain dollar-based thresholds.

The HSR Act rules also apply to many other scenarios that are treated like bilateral acquisitions, and which may thus trigger filing obligations. These include, for example, formations of for-profit joint venture entities, tender offers or purchases on the open market, as well as compensatory grants of securities to employees. Failure to make a filing can result in stark punitive measures being imposed by the agencies.

The Form, which consists generally of information about the transaction and about the parties to the transaction, is used by the agencies to assess, among other things, anti-competitive impact. After filing the Form, and assuming the agencies do not raise any issues or make any secondary requests in the interim, the parties must observe a waiting period (typically 30 days) before the transaction reported in the Form can be consummated.

A. Assessing Whether a Filing Is Required

In order to establish whether a filing is required under the HSR Act, it is usually necessary to focus on a number of data points. These include: (1) identifying the "ultimate parent entities" or "UPEs" of the parties involved; (2) determining the nature of whatever is being acquired; (3) assessing the value of the consideration; and (4) considering the manner in which the transaction will be effected.

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[79] https://www.wsj.com/articles/washington-steps-in-to-referee-broadcom-vs-qualcomm-1520255307; https://www.nytimes.com/2018/03/12/technology/trump-broadcom-qualcomm-merger.html; https://techcrunch.com/2018/03/10/qualcomm-vs-broadcom/.

[80] "U.S. Keeps Huawei in Its Sights," *Wall St. J.* (Mar. 7, 2018), at B-1.

[81] https://techcrunch.com/2018/03/10/qualcomm-vs-broadcom/.

"Ultimate parent entity" is a term of art in the HSR Act context, and refers to an entity or person that is not controlled by another entity or person. "Control" is likewise a term of art, and can mean different things depending on the type of entity in question. For example, for corporations, "control" means holding 50% or more of the outstanding voting securities of an issuer, or having the contractual power to designate 50% or more of the directors. As one might surmise, it is conceivable that an entity might have two UPEs. Identifying the UPEs is important because many of the analyses or tests applied when determining whether a filing is required are conducted at the UPE level.

1. Size of Transaction and Size of Person Tests

The first test typically applied when assessing the need for filing is called the "size of transaction" test. As of July 2018,[82] if, as a result of the transaction, one UPE will hold voting securities, assets, and/or a controlling interest in a non-corporate entity with a value of US$337.6 million or more, the size of transaction test has been met. In this case, a filing will be required unless there is an applicable exemption. Cash on hand, interestingly, is not considered an asset when acquired.

On the other hand, if (as of July 2018), as a result of the transaction, one UPE will hold voting securities, assets, and/or a controlling interest in a non-corporate entity with a value between US$84.4 million and US$337.6 million, a filing (absent applicable exemptions) will be required if the "size of person" test (described below) is met. Below the US$84.4 million threshold, no filing is required.

As of July 2018, the size of person test is generally met if one UPE has net sales or assets of US$168.8 million or more, and the other UPE has net sales or total assets of US$16.9 million or more. For purposes of this test, net sales and total assets are usually based on the last regularly prepared annual income statement or balance sheet for the entity in question.

Note that there are a number of significant takeaways that can be gleaned from the manner in which the size of transaction test is articulated. The first is that this test is focused on voting securities, assets, and controlling interests in non-corporate entities. It follows that acquisitions of non-voting securities or non-controlling interests in a non-corporate entity would not cause a transaction to trip the size of transaction test.

Another important takeaway is that the size of transaction test looks at what the acquiring person will "hold" as a result of the transaction – ***not*** what the acquiring person will "acquire." This potentially becomes relevant when the acquiring person has previously acquired reportable items from the same seller.

The aggregation rules under the HSR Act require, for example, that currently held voting securities be aggregated with voting securities to be acquired from the same party when assessing whether the value of the transaction crosses one of the abovementioned thresholds. However, where acquisitions of assets are concerned, the aggregation requirement only extends to assets acquired within the previous 180 days.

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[82] Certain dollar thresholds under the HSR Act are adjusted for gross national product changes on an annual basis.

2. Exemptions

Even if both the size of transaction and size of person tests are met, it is still possible that a transaction might not require an HSR Act filing. Driven by various policy considerations, the HSR Act's rules provide for several different categories of exemptions which, if the facts around the transaction accommodate, allow the parties to proceed without making a filing. The following is a non-exhaustive survey of some of the more frequently relied-upon exemptions.

The first category of exemptions relates to situations where, for lack of a better phrase, nothing of substance (at least from an overall competitive standpoint) is really changing. This includes, for example, stock splits where the holder's percentage share of an issuer's outstanding voting securities has not increased. Certain reorganizations or intra-person transactions may also fall within this category.

There are also exemptions intended to cover acquisitions made in the ordinary course of business (e.g., acquisitions of goods intended for resale or consumption/production of other goods). Certain acquisitions of real property may also come within this category (e.g., acquisitions of office or residential property). As might be expected, the rules around what does/does not qualify for these exemptions can be rather complex and fact-sensitive.

There are also related exemptions for acquisitions made solely for investment purposes. Because of the highly subjective issue of whether something is acquired "for investment purposes," the HSR Act's rules have incorporated an objective element—a transaction that appears to be made for investment purposes and which does not result in the acquiring person holding 10% or more of the issuer's outstanding voting securities will be exempt.

Another frequently used family of exemptions relates to certain asset categories—in this case, acquisitions of carbon-based mineral reserves. Acquisitions of reserves of oil, gas, shale, or tar sands, together with "associated exploration or production assets," are exempt up to a transaction value of US$500 million. Where acquisitions of coal reserves (and related exploration/production assets) are concerned, the exemption has a lower threshold—up to US$200 million. Unlike certain other thresholds within the HSR Act's rules, these are not adjusted from year to year.

What if the acquiring person is not buying the assets directly, but is instead purchasing a company whose assets are overwhelmingly composed of exempt assets (such as oil or gas reserves)? The HSR Act's rules include a "substance over form" provision that allows you to focus on the underlying assets of an entity that is being acquired. In that case, assuming a portion of the seller's assets consist of exempt assets (e.g., oil reserves of less than US$500 million in value), you would focus on the value of the non-exempt assets held the company. If the value of such non-exempt assets is less than the applicable size of transaction threshold, no filing is required.

Lastly, certain transactions are exempted from filing requirements if they do not have a sufficient nexus with commerce in the United States. For example, under current thresholds, acquisitions between two U.S.-domiciled parties of assets located outside the United States will be exempt, provided that the foreign assets in question did not generate sales in or into the United States of more than US$84.4 million during the most recent fiscal year.

A similar exemption exists for acquisitions of a foreign issuer's voting securities by a U.S. person. In this case, the key questions are whether or not the foreign issuer either: (1) holds assets in the U.S. valued at US$84.4 million or more, or (2) had sales in or into the United States of US$84.4 million or more during the most recent fiscal year.

A less frequently used, but potentially relevant, exemption with respect to foreign transactions arises in the scenario where one of the parties is controlled by a foreign state or agency thereof. If the assets in question are located in that particular country (or if the acquired entity is organized in that particular country), the transaction is exempt.

B. Preparing and Submitting an HSR Form

Assuming that a filing is required, the parties may submit their respective HSR Forms and exhibits to the FTC and DOJ at any time after the execution of *either* a letter of intent *or* of a full transaction agreement. At the time of filing, the Forms must be accompanied by a filing fee, which is typically wired to the U.S. Treasury, and the amount of which is determined by the "value" of the transaction in question. The Forms and exhibits may be submitted in paper format, or in CD-ROM format. In addition, a responsible person for each filer must include an affidavit attesting to the parties' *bona fide* intent to consummate the transaction(s) described in either the letter of intent or full agreement.

1. Information Required in an HSR Form

Certain of the information required to be provided in the Form is fairly straightforward. The Form requires, for example, that the identities of the acquiring and acquired UPEs be listed, as well as information about the entities or assets being acquired, the value of the transaction. The parties will also be required to provide a brief summary of the transaction, which should typically be developed as a joint effort.

While there are other sections of the Form which may require outside assistance, the two sections which tend to create the most confusion (and which carry the greatest risk for a rejected/returned Form) relate to the provision of revenue data as well as what is commonly referred to as "Item 4 information."

While revenue data for filer is not something difficult to obtain, the buyer and seller are each expected to report, in their respective forms, their recent revenue data organized according to industry codes. The codes that the Form expects filers to use are disseminated by the Census Bureau, and are referred to as NAICS (North American Industry Classification System) codes. Filers may be unaccustomed with using NAICS codes, and as a consequence, organizing the revenue data may require some lead time.

Collecting the so-called "Item 4 information" may, however, be one of the more complex tasks in preparing a Form. The Form instructions specify in detail what types of documents are responsive to Item 4, but speaking very generally, these tend to include documents, reports, or analyses, prepared for or by the company, that speak to market share, competition, growth, or synergies with respect to a particular transaction.

Certain categories of documents will always need to be produced. These include confidential information memoranda prepared for buyers, as well as

studies, surveys, and reports prepared by investment bankers or similar advisors that touch on the topics described above (e.g., market shares or sales growth).

The potential scope of what is an "Item 4 document" is broad, and extends to internal board presentations, as well as to internal e-mail communications, if the Form criteria are met. However, certain types of documents are explicitly excluded, such as most ordinary course materials developed without a clear tie to the specific transaction. Depending on the number of individuals on a particular "deal team," collecting and analyzing potentially responsive documents can be quite time and resource intensive.

While the buyer and seller will each separately conduct document collection processes, it is typically the case that there will be some overlap across Item 4 documents (for example, if a confidential information memorandum was produced for a transaction). Consequently, a small degree of communication is expected between HSR Form preparers for each side, in order to avoid scenarios where one side attaches an exhibit that the other side ostensibly should also have in their possession.

2. Review of the HSR Forms

Assuming that the Forms have been properly completed and are accompanied by the requisite exhibits, and further assuming that the filing fees have been successfully wired and received, the staff of the FTC typically notifies the parties in writing that their 30-day waiting period has officially commenced (and usually a specific day/time is identified as the point at which the waiting period will end). Prior to the expiration of the waiting period, the parties may not consummate the transaction (whether via a formal closing, or by taking certain actions that are deemed by the agencies to be a *de facto* closing). Failure to observe the waiting period can lead to significant financial penalties.

During the waiting period, the agencies' staff will review the contents of each party's Form in order to understand the proposed transaction, and to arrive at a view as to whether the transaction presents anticompetitive concerns. It is critical that the parties present a consistent approach and tell a consistent "story" in their Forms. It is also important that neither party inadvertently omit potentially responsive exhibits, as noted above.

If the reviewers have minor questions or points of clarification, they may reach out to the filers during the waiting period for additional information. Depending on the materiality of the question, such inquiries may not toll or interrupt the waiting period. However, if the staff have more substantive concerns, they may issue a formal "Second Request" to one or both parties, which usually will result in the waiting period being suspended indefinitely.

If, however, the staff have no questions and are comfortable that the transaction presents no anticompetitive concerns, they will typically just let the waiting period run its full course, without further correspondence to the filers.

3. Early Termination

Either party may, at the time of filing, request early termination ("ET") of the waiting period. An ET request does not necessarily mean that early termination will be granted by the agencies, nor does it obligate the agencies' staff to render a decision on such early termination by any specific point during the 30-day window.

In the event that ET is granted by the staff, the agencies are required to publicly disclose the fact that it was granted, as well as the identity of the acquired/acquiring Persons, and must also identify the acquired entities. This information is typically included in the *Federal Register*, and is also made known on the FTC's website here:

https://www.ftc.gov/enforcement/premerger-notification-program/early-termination-notices.

Any other information regarding the filing or the filers is not part of these early termination notices.

Other than the exception noted above in the case of ET grants, section 7A(h) of the Clayton Act, 15 U.S.C. § 18a(h), generally provides that HSR Act material (referring to "[a]ny information or documentary material" filed with the DOJ or the FTC pursuant to the HSR Act) must be kept confidential by the staff, and may not be made public "except as may be relevant to any administrative or judicial action or proceeding."

As a consequence, the decision of whether to request ET should be driven both by the level of urgency around closing the transaction, and by the parties' sensitivity to the existence of the filing becoming public.

4. Gun Jumping

"Gun jumping" is an issue that is not technically part of the process of preparing and submitting a Form, but nonetheless has the potential to arise in connection with filing a Form. The term itself refers to an unspecified, imaginary line that is crossed when the parties to a transaction take enough steps—whether by coordinating market activity, integrating personnel and operational elements, or simply by exchanging certain sensitive information outside of the due diligence process—such that a *de facto* consummation of the transaction has occurred, even if the formal closing has yet to take place.

There are potentially significant civil penalties that can be levied if the agencies determine that the parties have "jumped the gun," since it is considered a violation of the mandated waiting period under the HSR Act. Complicating matters is the fact that there is a limited body of case law that might clearly delineate the activities that are/are not permitted prior to closing.

At a high level, parties are generally permitted to plan for post-transaction integration. Exchanges of information to facilitate merger and transition planning are not per se prohibited, so long as there is a strong, bona fide, business justification. However, the extent of these planning activities should not place the parties' status as independent economic actors into doubt, and under no circumstances should control of any business elements be transferred.

The advice typically conveyed to parties revolves around limiting the exchange of competitively sensitive information except when required for due diligence purposes, and even then, limiting the number of individuals obtaining such information. It is also common to advise employees not to engage in communications with the "other side" about post-transaction pricing or customer information. By extension, information that is obtained from the other side should not play into any pricing decisions prior to the closing. Lastly, it can be helpful to remind employees that the parties are expected to remain separate businesses until closing occurs.

IV. Conclusion

Sophisticated due diligence practices will review and assess the factors associated with potential filing requirements under CFIUS and the HSR Act to avoid playing regulatory roulette. Both CFIUS and the HSR Act require atypical due diligence attention since they involve both the buyer and the seller. At a minimum, parties need to understand the CFIUS and HSR Act requirements, determine whether they apply, prepare the buyer and the seller for the implications of these regulatory schemes and draft the purchase and sale agreement in a manner that reflects the expected requirements. Both of these regulatory schemes may otherwise spring an unwelcome trap on the unwary, since they have the potential to lead to a federal government veto of your proposed transaction, which would lead to an early end to the game and very unhappy player-participants.

Nuisance Cases Against Energy Companies

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Synopsis

For over a century, courts and commentators have openly expressed their frustration with the amorphous doctrine of nuisance. It has been ridiculed as a "'wilderness' of law,"[1] an "impenetrable jungle,"[2] and a "mongrel" doctrine.[3] Professor Seavey, reporter for the First Restatement of Torts, noted that nuisance doctrine sometimes appeared to be a "mystery, smothered in verbiage."[4] Dean Prosser, reporter for the Second Restatement of Torts, candidly called it "a sort of legal garbage can."[5] Half a century later, Justice Blackmun searched "in vain . . . for anything resembling a principle in the common law of nuisance."[6]

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[1] 1 H.G. WOOD, A PRACTICAL TREATISE ON THE LAW OF NUISANCES IN THEIR VARIOUS FORMS: INCLUDING REMEDIES THEREFOR AT LAW AND IN EQUITY iii (3d ed. 1893).

[2] WILLIAM L. PROSSER, THE LAW OF TORTS 592 (3d ed. 1964).

[3] F.H. Newark, *The Boundaries of Nuisance*, 65 L.Q. REV. 480, 480 (1949).

[4] Warren A. Seavey, *Nuisance, Contributory Negligence and Other Mysteries*, 65 HARV. L. REV. 984, 984 (1952) (internal quotations and citation omitted); *see* Louise A. Halper, *Untangling the Nuisance Knot*, 26 B.C. ENVT'L AFF. L. REV. 89, 89 (1998) (summarizing Seavey's critiques).

[5] William L. Prosser, *Nuisance Without Fault*, 20 TEX. L. REV. 399, 410 (1942) [hereinafter

In Texas and other jurisdictions with significant oil and gas development, things have fared no better. At the turn of the twentieth century, the Texas Supreme Court concluded that nuisance must turn on whether a defendant's use is "reasonable," but it could not "furnish a more definite rule."[7] In the 1970s, the court frankly stated that "[t]here is a general agreement that [nuisance] is incapable of any exact or comprehensive definition, and we shall attempt none here."[8] In the early 2000s, the court noted that numerous Texas nuisance cases were completely irreconcilable because they were decided without a standard of reference.[9]

Energy companies increasingly have been the target of suits alleging that drilling operations were a nuisance to nearby residents.[10] But saying something is

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Nuisance Without Fault]; *see* Halper, *supra* note 4, at 89 (summarizing Prosser's critiques).

[6] Lucas v. S.C. Coastal Council, 505 U.S. 1003, 1055 (1992) (Blackmun, J., dissenting).

[7] Gulf, Colo. & Santa Fe Ry. Co. v. Oakes, 58 S.W. 999, 1001 (Tex. 1900).

[8] Wales Trucking Co. v. Stallcup, 474 S.W.2d 184, 186 (Tex. 1971).

[9] Schneider Nat'l Carriers, Inc. v. Bates, 147 S.W.3d 264, 274–75 (Tex. 2004), *holding modified on other grounds*, Gilbert Wheeler Inc. v. Enbridge Pipelines (E. Tex.), L.P., 449 S.W.3d 474 (Tex. 2014).

[10] Some cases are still pending in the trial court. Others are pending in various stages of appeal. A great many others have been dismissed, often pursuant to a settlement agreement. *See, e.g.*, Murray v. EOG Res., Inc., No. 342-284983-16 (342d Dist. Ct., Tarrant Cnty., Tex. dismissed Feb. 17, 2017); Smith v. Devon Energy Prod. Co., No. 4:11-cv-00104-RAS-DDB (E.D. Tex. dismissed July 1, 2012); Harris v. Devon Energy Prod. Co., No. 4:10-CV-00708-MHS-AM (E.D. Tex. dismissed Jan. 25, 2012), *aff'd as modified*, 500 F. App'x 267 (5th Cir. 2012); Mitchell v. Encana Oil & Gas (USA), Inc., No. 3:10-CV-02555 (N.D. Tex. dismissed Dec. 27, 2011); Scoma v. Chesapeake Energy Corp., No. 3:10-cv-01385-N (N.D. Tex. dismissed Dec. 9, 2011) (dismissed with prejudice); Beck v. ConocoPhillips Co., No. 2011-484 (123d Dist. Ct,. Panola Cnty. dismissed Tex. May 27, 2015) (dismissed with prejudice); Finn v. EOG Res., Inc., No. C201300343 (18th Dist. Ct., Johnson Cty., Tex. dismissed Apr. 13, 2015) (dismissed with prejudice); Heinkel-Wolfe v. Williams Prod. Co., No. 2010-40355-362 (362d Jud. Dist. Ct., Denton Cnty., Tex. dismissed Dec. 3, 2014) (dismissed with prejudice); Alexander v. Eagleridge Operating, LLC, No. 14-01430-393 (393d Jud. Dist. Ct., Denton Cnty., Tex. filed Feb. 28, 2014) (nonsuited without prejudice); Sizelove v. Williams Prod. Co., No. 2010-50355-367 (431st Jud. Dist. Ct., Denton Cnty., Tex. dismissed Jan. 8, 2013) (dismissed with prejudice); Knoll v. XTO Energy, Inc., No. 2010-10345-16 (431st Jud. Dist. Ct., Denton Cnty., Tex. dismissed May 16, 2012) (dismissed with prejudice); Ruggiero v. Aruba Petroleum, Inc., No. CV10-10-801 (271st Jud. Dist. Ct., Wise Cnty., Tex. dismissed Dec. 13, 2011); Strong v. ConocoPhillips Co., No. 2011-487 (123d Dist. Ct., Panola Cnty., Tex. Dec. 2, 2011); Mann v. Chesapeake Operating, Inc., No. 2011-008232-3 (Co. Ct. at Law No. 3, Tarrant Cnty., Tex. dismissed Dec. 10, 2014) (dismissed with prejudice); Gutierrez v. Chesapeake Operating, Inc., No. 2011-008274-3 (Co. Ct. at Law No. 3, Tarrant Cnty., Tex. dismissed Dec. 10, 2014) (dismissed with prejudice).

A few have reached final judgment. *See, e.g.*, Dueling v. Devon Energy Corp., No. 4:14-cv-325-Y (N.D. Tex. filed Oct. 2, 2014), *vacated and remanded*, 623 F. App'x 127 (5th Cir. 2015) (final judgment Nov. 30, 2016); Town of Dish v. Atmos Energy Corp., 519 S.W.3d 605 (Tex. 2017); Crosstex N. Tex. Pipeline, L.P. v. Gardiner, 505 S.W.3d 580 (Tex. 2016); Lipsky v. Range Prod. Co., No. 02-12-00098-CV, 2012 Tex. App. LEXIS 7059 (Tex. App.—Fort Worth Aug. 23, 2012, pet. denied) (final judgment Nov. 27, 2017); Cerny v. Marathon Oil Corp., No. 13-05-00118-CVK (218th Jud. Dist. Ct., Karnes Cnty., Tex. filed May 21, 2013), *aff'd*, 480 S.W.3d 612 (Tex. App.—San Antonio Oct. 7, 2015, pet. denied) (summary judgment in favor of defendants affirmed on appeal); Anglim v. Chesapeake Operating, Inc., No. 2011-008256-1 (Co. Ct. at Law No. 1, Tarrant Cnty., Tex. filed Nov. 9, 2011), *vacated*, No. 02-14-00218-CV, 2014 Tex. App. LEXIS 12985 (Tex. App.—Fort Worth Dec. 4, 2014, no pet.) (defense verdict, vacated pursuant to settlement agreement after appeal); Crowder v. Chesapeake Operating, Inc., No. 2011-008169-3 (Co. Ct. at Law No. 3, Tarrant Cnty., Tex. filed Nov. 7, 2011), *vacated*, No. 02-14-00323-CV, 2014 Tex. App. LEXIS 13003 (Tex. App.—Fort Worth Dec. 4, 2014, no pet.) ($20,000 award, vacated pursuant to settlement agreement after appeal); Marsden, Jr. v. Titan Operating, LLC, No. CV11-0842 (415th Jud. Dist. Ct., Parker Cnty., Tex. filed July 27, 2011), *rev'd*, No. 02-14-00303-CV, 2015 Tex. App. LEXIS 9076 (Tex. App.—Fort Worth Aug. 27, 2015, pet. denied) ($18,000 judgment; reversed and take-nothing judgment rendered on appeal); Parr v. Aruba Petroleum, Inc., No. CC-11-01650-E (Co. Ct. at Law No. 5, Dallas Cnty., Tex.

a nuisance case, as the Texas Supreme Court recently noted, "does not tell you much."[11] A variety of things have generated nuisance allegations against energy companies, such as bright lights on drilling rigs, vibrations from drilling, odor from condensate tanks, exhaust fumes from trucks, dust from construction, and noise from compressor stations.[12] Some cases allege personal injury; others allege only property damage. Some claim intentional behavior; some claim negligent behavior; others only claim that the condition was out-of-place with its surroundings.

Given the muddled state of nuisance law, this article first outlines the history of nuisance law to give context to the present confusion. With that historical context in mind, it then discusses modern private nuisance in Texas—what it is, what it is not, and a host of issues surrounding recent nuisance cases.

I. HISTORY

Nuisance law is ancient. Its roots go back to at least the early thirteenth century.[13] So too does the confusion surrounding the term.[14] The term "nuisance" means only "hurt, annoyance, or inconvenience."[15] In its infancy, it described "interferences to servitudes" (such as easements) "or other rights to the free use of land."[16] Early nuisance cases were brought under the old writ system and provided civil relief for invasions not covered by a writ of trespass; that is, invasions of property that did not directly cross the property's boundary.[17]

Nuisance therefore originally connoted a connection to property, but from the outset it was unclear if nuisance dealt with property rights, personal rights, or both.[18] This vagueness plagued early definitions in much the same way as it

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filed Mar. 8, 2011), *rev'd*, No. 05-14-01285-CV, 2017 Tex. App. LEXIS 873 (Tex. App.—Dallas Feb. 1, 2017, no pet.) ($2.9 million judgment; reversed and take-nothing judgment rendered on appeal).

[Disclosure: Author Mazzone was counsel for Aruba Petroleum in the *Parr* and *Ruggiero* cases and Haynes & Boone was counsel for Enbridge in the case consolidated from the *Dow*, *Town of DISH*, and *Sciscoe* cases.]

[11] Crosstex N. Tex. Pipeline, L.P. v. Gardiner, 505 S.W.3d 580, 587 (Tex. 2016).

[12] *See* cases cited *supra* note 10.

[13] C.H.S. FIFOOT, HISTORY & SOURCES OF THE COMMON LAW: TORT & CONTRACT 7 (1949) (tracing the roots of nuisance doctrine and noting that by "the early years of the thirteenth century cases of nuisance were not uncommon; but there had been no attempt at generalization"); FOWLER V. HARPER, FLEMING JAMES, JR. & OSCAR S. GRAY, HARPER, JAMES & GRAY ON TORTS § 1.23, at 90–91 [hereinafter HARPER] ("The recognition of nuisance as tort goes back at least to the thirteenth century . . . .").

[14] *See* P.H. Winfield, *Nuisance as a Tort*, 4 CAMB. L.J. 189, 189 (1931) (noting that Professor Winfield began his history of nuisance as a tort by stating that "[i]t would clear the ground if we could start with a definition of nuisance, but it has been truly said that it is not a term capable of exact definition, and, considering its historical origin, we should be astonished if it were" (internal citation omitted)).

[15] *See* 3 WILLIAM BLACKSTONE, COMMENTARIES ON THE LAWS OF ENGLAND 216 (1796).

[16] W. PAGE KEETON ET AL., PROSSER & KEETON ON TORTS § 86, at 617 (5th ed. 1984) [hereinafter PROSSER & KEETON]; *see* FIFOOT, *supra* note 13, at 3–11.

[17] FIFOOT, *supra* note 13, at 9–10; KEETON ET AL., *supra* note 17, § 86.

[18] Winfield, *supra* note 14, at 189–90 (noting this confusion likely began with the thirteenth century writings of Henry de Bracton); *see also* FIFOOT, *supra* note 13, at 3 (stating that nuisance was "concerned more or less intimately with incidents of property" but cautioning that a "student of legal history [should] take constant care not to apply to mediaeval conditions the current categories of tort, contract, and property").

plagues modern ones.[19] To the extent nuisance had any discrete historical meaning, it denoted an infringement of the use and enjoyment of property—much like private nuisance today.[20]

The term, however, became even more unbound through "a series of historical accidents."[21] The first of these is the parallel development of a "catch-all low-grade criminal offense" also called "nuisance"—now generally referred to as public nuisance, to distinguish it from private nuisance.[22] By the mid-thirteenth century, this broad offense included "obstructed highways, lotteries, unlicensed stage-plays, and a host of other rag ends of the law" which involved infringements of "public rights."[23] Put simply, the offense of public nuisance had nothing in common with private nuisance, except that both concern "annoyance or inconvenience."[24]

This might have been little more than a historical oddity if public nuisance remained strictly a criminal offense with no civil remedy. But that did not happen. By the sixteenth century, courts had recognized that an individual who suffered damage different from the rest of the public had a civil remedy for damages caused by the nuisance.[25] Adding to the confusion, public nuisances can also sometimes be both public and private nuisances.[26] The classic example is a brothel that is a public nuisance that may also interfere with the use and enjoyment of a neighbor's land in such a way as to also constitute a private nuisance.[27]

A second historical accident is that the term "nuisance" began to be used to refer to different legal concepts. Among other things, courts used nuisance to mean (1) a discrete cause of action, (2) the defendant's conduct or activity, and (3) the harm caused by the defendant's conduct or activity.[28] This loose usage partially may have stemmed from the loose definition itself.[29]

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[19] Winfield, *supra* note 14, at 190 (1931) ("The best that Blackstone could do with it was 'anything done to the hurt or annoyance of the lands, tenements, or hereditaments of another,' but even then he made more to say in another chapter entitled 'Of Disturbance' about matters, some of which are now regarded as nuisances."). More modern definitions have also attempted to straddle the line between property rights and personal rights. *See Crosstex*, 505 S.W.3d at 592 ("[T]he Court's early opinions" showed that a defendant "could be liable for harming a wide variety of the plaintiffs' interests by, for example, harming the plaintiffs' health, offending the plaintiffs' 'senses,' or interfering with the plaintiffs' enjoyment of, or operation of a business on, their land." (citations omitted)); THOMAS COOLEY, A TREATISE ON THE LAW OF TORTS OR THE WRONGS WHICH ARISE INDEPENDENT OF CONTRACT (1880) (relegating nuisance to a late chapter for a discussion separate from wrongs affecting personal security or invasions of property); *cf.* Milwaukee v. Illinois, 451 U.S. 304, 317 (1981) (noting the "vague and indeterminate" nature of nuisance concepts).

[20] Winfield, *supra* note 14, at 189–90.

[21] KEETON ET AL., *supra* note 16, § 86.

[22] *Id.*

[23] *Id*. (quoting Newark, *supra* note 3, at 482).

[24] *Nuisance Without Fault*, *supra* note 5, at 411.

[25] *See* KEETON ET AL., *supra* note 16, § 86; *see also* BLACKSTONE, *supra* note 15, at 220 ("Yet this rule [of criminal liability] admits of one exception; where a private person suffers some extraordinary damage, beyond the rest of the king's subjects, by a public nuisance: in which case he shall have a private satisfaction by action.").

[26] *See* KEETON ET AL., *supra* note 16, § 86.

[27] *See* RESTATEMENT (SECOND) OF TORTS § 821B cmt. h (AM. LAW INST. 1979).

[28] *See id.*; *see also Crosstex*, 505 S.W.3d at 594.

[29] *See* Winfield, *supra* note 14, at 189–90. "Nuisance" has also been used in conjunction with the attractive-nuisance doctrine, which deals with dangerous conditions that may lure children to trespass.

But changes in the English legal system also may have played a part in the varied usage of the term "nuisance." In its earliest form, a plaintiff could only bring a nuisance action through one of the specialized common law writs.[30] By the late fourteenth century, however, English law had recognized an action for "trespass on the case" which covered a variety of indirect harms.[31] For reasons mainly of convenience and strategy, trespass on the case entirely superseded the old writs that lawyers had used to bring nuisance cases.[32] Trespass on the case, however, was a sort of catch-all action. It covered a variety of "indirect" legal harms, such as fraud and defamation—not just nuisance.[33] As a result of this shift away from the specialized nuisance writs, nuisance may have lost some of its character as a discrete form of action.[34]

Much later, history provided a third twist. From the thirteenth century to the mid-nineteenth century, the common law forms of action—such as trespass on the case and the various writs of trespass—determined the necessary elements of a case and the defenses and remedies available.[35] For a plaintiff, "choosing the wrong form of action was fatal to the case"—the plaintiff's case would be dismissed "even if facts were shown that would entitle recovery in another form."[36] Facing criticism that such formalism was unjust, jurisdictions across the county largely abandoned the common law forms of action and the writ system in the latter half of the nineteenth century.[37]

The initial shift away from the writ system was largely procedural, however. Under the new, more liberal pleading rules, a plaintiff was not required to specify the form of action, but the plaintiff still had to plead facts that constituted a cause of action that was recognized under the old system.[38] In other words, the rules of

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See, e.g., *Nuisance Without Fault*, *supra* note 5, at 410. Attractive nuisance is a concept entirely separate from private nuisance and public nuisance. *See id.*

[30] Winfield, *supra* note 14, at 190–92 (discussing the assize of nuisance, the action *quod permittat prosternere*, and the writ of trespass); *see also* BLACKSTONE, *supra* note 155, at 220–22.

[31] *See* Winfield, *supra* note 14, at 191–92.

[32] *Id.* (discussing the various factors which led to trespass on the case becoming the "sole Common Law action" for nuisance); *see also* KEETON ET AL., *supra* note 17, § 86.

[33] *See* EDWIN E. BRYANT, THE LAW OF PLEADING UNDER THE CODES OF CIVIL PROCEDURE 7 (1894); 1 AM. JUR. 2D *Actions* § 18 (1994).

[34] This kind of usage problem arises in other areas of the law as well, so this ambiguity may not be a particular historical quirk of nuisance. *See, e.g.*, Robert L. Rabin, *The Historical Development of the Fault Principle: A Reinterpretation*, 15 GA. L. REV. 925, 932 (1981) (discussing ambiguity with regards to negligence).

[35] *See* Kenneth J. Vandevelde, *A History of Prima Facie Tort: The Origins of a General Theory of Intentional Tort*, 19 HOFSTRA L. REV. 447, 454 (1990).

[36] Coastal Oil & Gas Corp. v. Garza Energy Trust, 268 S.W.3d 1, 10 & n.27 (Tex. 2008) (quoting, in part, HARPER § 1.3, at 11).

[37] *Id.* at 10 n.27 (quoting HARPER § 1.3, at 11); *see* Vandevelde, *supra* note 35, at 454–55. A few writs, such as the writ of certiorari, the writ of habeas corpus, and the writ of attachment, survived the transition with their names intact. For its part, Texas never recognized the common law forms of action. Banton v. Wilson, 4 Tex. 400, 406 (1849) ("All forms of action have been abolished in our system of jurisprudence, or rather they were never introduced."); *see* Chevalier v. Rusk, Dallam 611, 613 (Tex. 1844) (stating, before statehood, that "[u]nder our statutes, intended to simplify the rules of pleading, no distinctions as to forms of action are recognized").

[38] *See* Vandevelde, *supra* note 35, at 455; *Coastal*, 268 S.W.3d at 10 ("[U]nder our liberal pleading rules, unlike the common law, [plaintiff] was not required to specify which form [of action applied].").

substantive law did not change: "In determining what facts were necessary to state a cause of action, courts referred back to the common law writs."[39]

The abolition of the common law forms of action, however, opened the door for courts and scholars to reimagine tort doctrine and to reorganize it around fault-based principles.[40] Parallel to the shift away from the writ system, negligence in the modern sense—a failure to exercise reasonable care—also entered the scene.[41] Although there is some disagreement among scholars, the majority view is that most torts, including nuisance, largely did not operate on fault-based principles prior to the advent of negligence.[42]

The shift to fault-based liability and its effect on nuisance (and other torts) is perhaps best exemplified by the treatises of the day. Early American torts treatises were generally organized around the age-old principle that "where there is a legal right, there is also a legal remedy."[43] For example, one 1880 torts treatise included chapters such as "Wrongs Affecting Personal Security," "Invasions of Rights in Real Property," and "Wrongs in Respect to Personal Property," and discussed the various causes of action—assault, false imprisonment, trespass, trespass to chattels, and so on—that remedied the invasions of those rights under those headings.[44] Consistent with the idea that torts did not operate based on fault, the treatise concluded that "the good or bad motive which influenced the action complained of is generally of no importance whatsoever."[45]

By the late 1880s, however, torts treatises began to take a different shape. Influenced by the writings of Oliver Wendell Holmes and other legal theorists, scholars began to organize their treatises around the notion that tort liability fell into three classes: intentional torts, negligence, and strict liability torts.[46] This

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[39] *See* Vandevelde, *supra* note 35, at 455 & n.58 ("[T]he abolition of the common-law forms of pleading has not changed the rules of substantive law" (quoting O.W. HOLMES, THE COMMON LAW 67 (M. Howe ed. 1963))); *see also Coastal*, 268 S.W.3d at 9–10 (rejecting argument that plaintiff lacked standing to sue for trespass because plaintiff had sufficiently pled an action for "trespass on the case").

[40] HARPER ET AL., *supra* note 13, § 1.24 (arguing the "procrustean insistence on fault" in nuisance doctrine is misguided and "quite in keeping with the late-nineteenth- and early twentieth-century urge to reduce all tort liability to terms of fault").

[41] *See* Vandevelde, *supra* note 35, at 455 ("The conventional wisdom is that the emergence of modern negligence began with the 1850 decision in *Brown v. Kendall* by Chief Justice Lemuel Shaw of Massachusetts." (internal footnote omitted)).

[42] *See id.* at 450 ("Until Holmes conceptualized American tort law, all of the classic intentional torts rested on strict liability."); Richard A. Posner, *A Theory of Negligence*, 1 J. LEGAL STUD. 29, 29–30 & n.3 (1972) ("There is an orthodox view of the negligence concept to which I believe most legal scholars and historians would subscribe that runs as follows: Until the nineteenth century a man was liable for harm caused by his accidents whether or not he was at fault; he acted at his peril . . . [but] whether the period before the advent of the negligence standard is properly characterized as one of liability without fault remains, so far as I am aware, an unresolved historical puzzle."); *see also* HARPER § 1.24, at 111.

[43] *See* Marbury v. Madison, 5 U.S. (1 Cranch) 137 (1803) ("[I]t is a general and indisputable rule, that where there is a legal right, there is also a legal remedy, by suit or action at law, whenever that right is invaded"); *see also* BLACKSTONE, *supra* note 15, at 116 ("[S]ince all wrongs may be considered as merely a privation of right, the plain natural remedy for every species of wrong is the being put in possession of that right whereof the party injured is deprived."); *see also* Vandevelde, *supra* note 35, at 455–57 (also arguing that some early American tort treatises could hardly be called organized at all).

[44] COOLEY, *supra* note 19; *see* Vandevelde, *supra* note 35, at 455–57 (discuss early American tort treatises). This approach mirrored William Blackstone's organization in his Commentaries on the Laws of England, published in 1765. *See* Vandevelde, *supra* note 35, at 455–57.

[45] COOLEY, *supra* note19, at 830.

[46] *See* FREDERICK POLLOCK, THE LAW OF TORTS 6 (The Blackstone Pub. Co. 1887). This shift is

fault-based liability system did not jettison the rights-and-remedies model, however; it supplemented it.[47] So, for example, an 1887 treatise still addressed rights and remedies such as "Personal Wrongs," "Wrongs to Person, Estate, and Property generally," and "Wrongs to Property."[48] But grafted on top of the rights-and-remedies model was a requirement of fault. "Personal Wrongs," such as assault, battery, and false imprisonment, were only actionable if they were intentional; "Wrongs to Person, Estate, and Property generally" were only actionable if the actor was negligent; and "Wrongs to Property," such as trespass to land or chattels, were strict liability torts.[49] For the first time treatises spoke of fault as a requirement—unless a tort was a strict liability tort, fault was now an explicit element. This is the basic model that survives to the present day.[50]

Troublesome as always, nuisance did not fit cleanly into the new fault-based approach. One early treatise lumped nuisance in with negligence.[51] Another placed nuisance under strict-liability torts.[52] By the time the First Restatement of Torts was published in 1939, the prevailing view was that, unlike other torts, nuisance could be an intentional, negligent, or strict liability tort.[53] This tripartite division of nuisance survives to the present day.[54]

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readily apparent in Melville Bigelow's torts treatise. *See* MELVILLE BIGELOW, ELEMENTS OF THE LAW OF TORTS: FOR THE USE OF STUDENTS v–vi (5th ed., 1894) (discussing the organizational changes from the 1878 edition to address fault-based liability).

[47] Holmes took the reorganization a step further, but his views were not universally accepted. In an 1873 article, Holmes proposed the three classes of tort liability. Vandevelde, *supra* note 35, at 457–58. By 1894, Holmes proposed jettisoning the distinction between intentional torts altogether. *Id.* at 475. Under this approach, the modern intentional torts—assault, battery, false imprisonment, and so on—would no longer be considered discrete causes of action and would be reorganized under a general theory of intentional tort that paralleled the general theory of negligence. *Id.* Modern courts and scholars refer to this idea as "prima facie tort." *See* RESTATEMENT (SECOND) OF TORTS § 870 & cmt. a (AM. LAW. INST. 1979).

While the Restatement and some courts have adopted "soft" versions of prima facie tort, Texas has rejected this theory of liability entirely. A.G. Servs., Inc. v. Peat, Marwick, Mitchell & Co., 757 S.W.2d 503, 507 (Tex. App.—Houston [1st Dist.] 1988, writ denied) ("[T]he adoption of such a cause of action [for prima facie tort is] a matter of public policy and is within the province of the Legislature, not the courts"); *see also* Wal-Mart Stores, Inc. v. Sturges, 52 S.W.3d 711, 717 (Tex. 2001) (noting that misassociation and confusion surrounding tortious interference torts "may have been due to, and were certainly exacerbated by, the concept of a prima facie tort that was being advanced [in the late nineteenth and early twentieth century]").

[48] POLLOCK, *supra* note 46, at 5–6.

[49] *Id.* at 5–8.

[50] *See, e.g.*, RESTATEMENT (SECOND) OF TORTS § 6, cmt. a (1979). The *Palsgraf* case is a notable example of a court discussing both rights-and-remedies and fault-based liability. *See* Palsgraf v. Long Island R. Co., 162 N.E. 99, 99 (N.Y. 1928) (Cardozo, J.) ("Negligence is not actionable unless it involves the invasion of a legally protected interest, the violation of a right. Proof of negligence in the air, so to speak, will not do.").

[51] POLLOCK, *supra* note 46, at 5–8.

[52] BIGELOW, *supra* note 46.

[53] *See* RESTATEMENT (FIRST) OF TORTS § 822 (AM. LAW INST. 1939).

[54] *See e.g.*, RESTATEMENT (SECOND) OF TORTS § 822 (AM. LAW INST. 1979). Professor Keeton advocated for limiting private nuisance to intentional private nuisance in order to limit confusion; negligent nuisance and strict liability nuisance would be handled as simple negligence cases and strict liability cases. *See* Crosstex N. Tex. Pipeline, L.P. v. Gardiner, 505 S.W.3d 580, 603 (Tex. 2016) ("When Keeton took over the commentary, however, he abandoned the three-category approach because 'the utilization of the same label ['nuisance'] to describe all these types of actionable conduct brings about much confusion regarding when the conduct is actionable and what the defenses to such

In Texas these three historical concepts—the development of public nuisance, the varied usage of the term, and the development of fault-based liability—all contributed to the development of modern nuisance doctrine and, predictably, along the way created much confusion that persists today.

II. MODERN PRIVATE NUISANCE

Texas—as well as other jurisdictions in oil and gas producing states including Colorado, West Virginia, North Dakota, Ohio, and New York—has adopted Sections 821 and 822 of the RESTATEMENT (SECOND) OF TORTS, outlining the elements of nuisance. While these elements remain part of the nuisance inquiry in those jurisdictions, the Texas Supreme Court concluded in a recent opinion that, "[g]iven the long and storied history of nuisance law, it is not surprising that the courts and parties in this case have struggled to articulate the elements of [the plaintiff's] nuisance claim."[55] The decision, *Crosstex North Texas Pipeline v. Gardiner*, provides some much-needed clarification for how the concept of nuisance will now be applied in Texas, and while not binding in other jurisdictions with significant energy development, may serve as guidance in such jurisdictions. But while *Crosstex* is perhaps the Texas Supreme Court's most comprehensive discussion of private nuisance to date, it does not answer every question—nor could it—and it is not binding on courts outside of the state.

This section outlines the general elements of nuisance law under the Sections 821 and 822 of the RESTATEMENT (SECOND) OF TORTS, which have been adopted by Texas courts, and examines some common issues that arise in connection with nuisance claims. We then describe how *Crosstex* addresses the historical "accidents" that have created much of the confusion surrounding nuisance. Finally, this section considers a few defenses in the nuisance context.

A. Elements of a Private Nuisance Case

To establish a claim for private nuisance in Texas,[56] and other jurisdictions that have adopted Sections 821 and 822 of the RESTATEMENT (SECOND) OF TORTS, a plaintiff must prove that the conduct at issue "is a legal cause of an invasion of another's interest in the private use and enjoyment of land, and the invasion is either (a) intentional and unreasonable, or (b) unintentional and otherwise actionable under the rules controlling liability for negligent or reckless conduct, or for abnormally dangerous conditions or activities."[57] For claims governed by jurisdictions adopting this definition, plaintiffs must prove (1) standing; (2) legal injury; (3) tortious conduct; (4) causation; and (5) actual damages. Each of these elements is discussed briefly below.

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conduct should be.'" (alteration in original)). The Texas Supreme Court rejected Keeton's approach in *Crosstex*. *Id.*

[55] *Crosstex*, 505 S.W.3d at 617.

[56] Despite discussing numerous aspects of Texas nuisance law in *Crosstex*, the court did not lay out a list of elements applicable to all nuisance claims. Therefore, even after *Crosstex*, it appears as though the elements of nuisance laid out in Sections 821 and 822 of the RESTATEMENT (SECOND) OF TORTS still apply.

[57] RESTATEMENT (SECOND) OF TORTS § 822 (1979).

1. **Standing.** The plaintiff must have a legally cognizable interest in the property.[58]

Because nuisance is related to property rights, sometimes there is a question as to whether those without legal title—such as tenants or a property owner's family members—have any right to complain of a nuisance. Generally, they do. At one time, a plaintiff only had standing if he was the landowner. Courts have since relaxed the standing requirement so that generally "any interest sufficient to be dignified as a property right will support the action."[59] The modern standing requirements, however, still exclude those such as employees, customers, and the like.

Comment a to Section 821E of the Restatement (Second) of Torts limits nuisance claims to those who have "property rights and privileges in respect to the use and enjoyment of the land affected," that is, "legally protected interests."[60] However, this does not necessarily require that those asserting a nuisance claim are property ***owners***: they merely must have a legal right associated with the property at issue.[61]

In Texas, a right to occupy the property—which tenants and a property owner's family members have—is sufficient to give a plaintiff standing. The type of standing held by a plaintiff does, however, affect the plaintiff's remedy. In other words, a plaintiff's right determines the remedy. While mere occupants of property may have standing to seek damages for personal injury, they generally cannot seek to recover permanent property damages.[62] However, there is some authority for the proposition that a mere occupant may, in certain circumstances, recover property damages without legal title.[63]

2. **Legal Injury.** A plaintiff must show *substantial* interference with the use and enjoyment of property that caused *unreasonable* discomfort or annoyance to the plaintiff.[64]

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[58] The Court did not expressly address standing in *Crosstex*, but the decision appeared to implicitly recognize standing as an element. *See generally Crosstex*, 505 S.W.3d 580 (discussing "plaintiffs' property" numerous times).

[59] KEETON ET AL., *supra* note 16, § 87.

[60] RESTATEMENT (SECOND) OF TORTS § 821E & cmt. a.

[61] *Id*.

[62] *See, e.g.*, *id.*; *id*. at cmt. b (the Restatement provision on nuisance "does not state the rules applicable in determining when a person's rights and privileges in respect to land constitute property rights and privileges" for purposes of standing in a nuisance suit, deferring instead to property law for that determination); Hot Rod Hill Motor Park v. Triolo, 293 S.W.3d 788, 790–91 (Tex. App.—Waco 2009, pet. denied) (applying Section 821E and holding that adult child, who listed parents' address as his address and stayed there with some regularity but did not pay bills or taxes on the property, lacked standing to bring a private nuisance claim); RESTATEMENT (SECOND) OF TORTS § 821E cmt. b (acknowledging that the Restatement provision on nuisance "does not state the rules applicable in determining when a person's rights and privileges in respect to land constitute property rights and privileges" for purposes of standing in a nuisance suit, deferring instead to property law for that determination).

[63] *See* New v. Khojal, No. 04-98-00768-CV, 1999 WL 675448, at *3, 7 (Tex. App.—San Antonio, Aug. 31, 1999, no pet.) (standing for property damages claim where man lived in deceased mother's home for over a decade, paid for taxes and repairs, and believed himself to be the owner of the house after his mother died).

[64] *See Crosstex*, 505 S.W.3d at 597.

There are not clearly delineated bounds on the types of interferences that may constitute a nuisance—"virtually any disturbance of the enjoyment of property may amount to a nuisance."[65] The interference may be physical damage to property, economic harm to property's market value, harm to the plaintiff's health, or psychological harm to the plaintiff's peace of mind in the use and enjoyment of the property.[66]

To constitute a nuisance under Texas law, however, the interference must be "substantial" and cause "unreasonable" discomfort and annoyance.[67] These conditions distinguish "nuisances" from "the petty annoyances and disturbances of everyday life."[68] However, unless the underlying facts are undisputed or reasonable minds cannot differ, these distinctions are generally questions of fact—"the practical judgment of an intelligent jury" must decide "[t]he point at which an odor moves from unpleasant to insufferable or when noise grows from annoying to intolerable."[69]

While legal injury issues are generally questions of fact, the Texas Supreme Court clarified two important legal points in *Crosstex*: (1) the focus is on the unreasonableness of the interference's effect on plaintiff's comfort or contentment and not on defendant's conduct; and (2) the determination must be based on an objective standard of persons of ordinary sensibilities and not on the subjective response of any particular plaintiff.[70] In short, to show a legal injury of nuisance, a plaintiff need not prove the defendant's conduct was unreasonable, but he cannot rely on his own particular sensitivities.

3. **Tortious Conduct.** The plaintiff must prove that the defendant intentionally, negligently, or through an abnormally dangerous activity interfered with the plaintiff's use and enjoyment.[71]

The proper standards for culpable conduct—whether a nuisance is intentional, negligent, or subject to strict liability—have been at issue in a number of recent cases. *Crosstex* clarifies these standards in Texas, though it leaves unanswered questions as to strict liability nuisance. Notably, some instructions in the Texas Pattern Jury charges on nuisance are now questionable in light of *Crosstex* and other case law.

To prove intentional nuisance, a plaintiff must establish that the defendant intentionally caused the interference, not just that the defendant intentionally engaged in the conduct that caused the interference.[72] Intent includes not only a desire to create an interference but also knowledge that the interference is substantially certain to result.[73] Intent does not entail an inquiry into whether the

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[65] *Id.* at 596.

[66] *Id.*

[67] *Id*. at 596–97.

[68] *Id.* at 595.

[69] *Id.* at 609 (quoting Nat. Gas Pipeline Co. of Am. v. Justiss, 397 S.W.3d 150, 155 (Tex. 2012)).

[70] *Id*. at 593–94.

[71] *See id.* at 599 n.11; *see also* RESTATEMENT (SECOND) OF TORTS § 821E (1979).

[72] *Crosstex*, 505 S.W.3d at 599 n.11; *see* RESTATEMENT (SECOND) OF TORTS § 821E & cmt. a.

[73] *Crosstex*, 505 S.W.3d at 606; *see* Aruba Petroleum, Inc. v. Parr, No. 05-14-01285-CV, 2017 Tex. App. LEXIS 873, at *18 (Tex. App.—Dallas Feb. 1, 2017, no pet.) (mem. op.) ("[T]he Parrs have not cited any evidence that Aruba knew who . . . made these complaints [about Aruba's conduct] or that

defendant's conduct is unreasonable.[74] It is the condition created by the interference, *i.e.*, the effects of the conduct, rather than the defendant's conduct that must be unreasonable.[75]

Negligent nuisance operates on ordinary negligence principles.[76] To establish negligence, a plaintiff must show the existence of a legal duty, a breach of that duty, and damages proximately caused by it.[77] To establish breach, a plaintiff must show that the defendant did or failed to do what a person of ordinary prudence in the same circumstances would have done or not done, that is, a failure to take precautions against a risk apparent to a reasonable man, *e.g.*, to repair or abate a condition under his control.[78]

For culpability based on abnormal or out-of-place conduct, *i.e.*, *Rylands v. Fletcher* strict liability, the underpinnings are based on the notion that the defendant engaged in activity exposing others to a risk of harm from an accidental invasion under circumstances that justify allocating loss from such risk to the defendant even though the defendant acted with reasonable care.[79] In other words, the focus is on the nature of the risk rather than on the nature of the interference:

> the mere fact that the defendant's use of its land is "abnormal and out of place in its surroundings" will not support a claim for nuisance; instead, in the absence of evidence that the defendant intentionally or negligently caused the nuisance, the abnormal and out-of-place conduct must be abnormally "dangerous" conduct that creates a high degree of risk of serious injury.[80]

Additionally, the Texas Pattern Jury Charges are questionable in light of *Crosstex* and other case law. The Texas Pattern Jury Charge on intentional nuisance states that "intentionally" includes that the defendant "acted with intent with respect to the nature of his conduct."[81] As noted above, *Crosstex* explicitly rejects this definition of intent.[82] The Texas Pattern Jury Charge on "abnormal and

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they were specific to the Parrs or their property.").

[74] *Crosstex*, 505 S.W.3d at 606.

[75] *Id.*

[76] *Id.* at 607.

[77] *Id.* (noting that, in addition to the ordinary negligence elements, there is a "unique element, which derives from the nature of the legal injury on which the plaintiff bases the claim, [of] the burden to prove that the defendant's negligent conduct caused a nuisance, which in turn resulted in the plaintiff's damages.").

[78] *Id.*

[79] *Id.*

[80] *Id.* at 609 (taking issue with the court of appeals' holding that the plaintiffs should have been allowed a trial amendment for an "abnormal and out of place" nuisance claim—there was no evidence in the record that the compressor station had engaged in the type of abnormally dangerous or ultra-hazardous conduct that would support such a cause of action).

[81] STATE BAR OF TEX., TEXAS PATTERN JURY CHARGES 12.2A (2018) ("'Intentionally' means that *Don Davis* acted with intent with respect to the nature of *his* conduct or to a result of *his* conduct when it was the conscious objective and desire to engage in the conduct or the result.").

[82] *Crosstex*, 505 S.W.3d at 605; *see also* City of Tyler v. Likes, 962 S.W.2d 489, 504 (Tex. 1997) (characterizing an intentional nuisance as a nuisance "inflicted by conduct which is intended to cause harm"); Aruba Petroleum, Inc. v. Parr, No. 05-14-01285-CV, 2017 Tex. App. LEXIS 873, at *17 (Tex. App.—Dallas Feb. 1, 2017, no pet.) ("Evidence that [the defendant] 'intentionally engaged in the conduct that caused the interference' is not sufficient to establish an intentional nuisance." (quoting *Crosstex*, 505 S.W.3d at 605)); City of Princeton v. Abbott, 792 S.W.2d 161, 166 (Tex. App.—Dallas

out of place in its surroundings" does not include any statement regarding "abnormally 'dangerous' conduct."[83] As noted above, Texas requires such conduct to impose strict liability nuisance.[84]

Regarding whether hydraulic fracturing and associated natural gas drilling operations are "abnormally dangerous" or "ultra hazardous," the availability of strict liability nuisance is an open question in Texas, where *Crosstex* left open questions on the viability and scope of this theory,[85] and in Ohio, where courts seem willing to consider differences between hydraulic fracturing and other extraction activities before deciding whether strict liability could apply.[86]

4. **Causation.** A plaintiff must prove that the defendant's conduct was a legal cause of the interference with the plaintiff's use and enjoyment of the property.[87]

Two causation issues are discussed below: (1) whether a plaintiff may avoid medical causation requirements under a nuisance theory and (2) whether a plaintiff may be required to comply with a "Lone Pine" case management order before discovery.

The first issue, whether a plaintiff may, under a nuisance theory, avoid medical causation requirements for personal injuries, has been litigated in two separate cases in Texas. In *Cerny v. Marathon Oil Corp.*, the plaintiffs claimed that Marathon's operations caused extensive property damage and noxious fumes, along with numerous physical ailments, including headaches, rashes, and nosebleeds.[88] The plaintiffs, however, disclaimed "disease" allegations and claimed to seek damages only for "discomfort."[89] Despite this disclaimer, the court granted Marathon's motion for summary judgment on grounds that the plaintiffs could not prove causation.[90] As to the plaintiffs' physical ailments, the court held that plaintiffs could not meet the medical causation requirements the Texas Supreme Court set forth in *Merrell Dow Pharmaceuticals, Inc. v. Havner*, requiring a plaintiff to present reliable expert testimony that establishes general

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1990, writ ref'd n.r.e.) ("An invasion is intentional if (1) the actor acts for the purpose of causing it, or (2) the actor knows that it is resulting or is substantially certain to result from his conduct.").

[83] *Compare* Tex. PJC 12.2C ("Was *Don Davis*'s conduct abnormal and out of place in its surroundings such as to constitute a public nuisance?"), *with*, *e.g.*, Tex. PJC 13.2 (for strict liability for vicious animals, asking "[o]n the occasion in question, did [the animal] have dangerous propensities abnormal to its class?").

[84] *Crosstex*, 505 S.W.3d at 605.

[85] *Id.* at 609 (noting that the Court was only addressing strict liability nuisance "to the extent that [such] a claim exists in Texas").

[86] Boggs v. Landmark 4, LLC, No. 1:12CV614, 2013 WL 944776 (N.D. Ohio Mar. 11, 2013) (declining to dismiss strict liability nuisance claim and noting that, in the context of hydraulic fracturing, factual development is necessary to decide whether defendants' activities were abnormally dangerous).

[87] *Crosstex*, 505 S.W.3d at 605.

[88] 480 S.W.3d 612, 622–23 (Tex. App.—San Antonio 2015, pet. denied).

[89] *Id.* at 615–16.

[90] *Id*. at 625.

and specific causation, establishes dose, and rules out other potential causes.[91] The court of appeals affirmed the trial court's grant of summary judgment.[92]

In *Parr v. Aruba Petroleum, Inc.*, the plaintiffs claimed property damage from Aruba's operations, as well as physical ailments such as headaches, rashes, and nosebleeds.[93] Aruba moved for summary judgment, arguing, like Marathon in *Cerny*, that the plaintiffs could not meet *Havner*'s causation requirements. To avoid *Havner*, the Parr plaintiffs, like the Cerny plaintiffs, disclaimed "disease" allegations and sought damages only for "discomfort."[94] The court granted summary judgment in part but allowed plaintiffs to seek damages for injuries within the common knowledge and experience of a layperson.[95] The plaintiffs then presented a "toxic tort" case to the jury. The jury awarded plaintiffs approximately $2.9 million, including almost $300,000 for diminution in property value.[96] On appeal, the court reversed and rendered a take-nothing judgment but did not reach the causation issue.[97]

Second, "Lone Pine" orders, which have been litigated recently in Colorado and other jurisdictions, may be a viable discovery tactic in some jurisdictions.[98] In many cases, energy companies have attempted to obtain "Lone Pine" orders requiring toxic tort plaintiffs to provide evidence of injury, exposure, and causation before discovery, facts generally only obtainable by the plaintiff, or face dismissal.[99]

In *Antero Resources Corp. v. Strudley*,[100] a Colorado district court entered a "Lone Pine" order requiring plaintiffs to make a prima facie showing linking their alleged personal injuries to the defendant's nearby oil and gas drilling.[101] In their lawsuit, the plaintiffs alleged that Antero's hydraulic fracturing operations contaminated their water well and caused a myriad of personal injuries.[102] When the plaintiffs failed to make a prima facie showing of any connection between Antero's activities and their injuries, the trial court dismissed the lawsuit with

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[91] *Id.* at 621–22; *see* Merrel Dow Pharm., Inc. v. Havner, 953 S.W.2d 706, 720 (Tex. 1997).

[92] *Cerny*, 480 S.W.3d at 625.

[93] Appellee's Brief at 10, Parr v. Aruba Petroleum, Inc., No. 05-14001285-CV, 2017 Tex. App. LEXIS 873 (Tex. App.—Dallas Feb. 1, 2017, no pet.), 2015 Tex. App. Ct. Briefs LEXIS 1635 at *14.

[94] *Id.* at *27. The plaintiffs in *Parr* added their "disclaimer" to their petition before the plaintiffs in *Cerny*, but the *Cerny* case reached final judgment before the *Parr* case.

[95] *Id.* at *38–39.

[96] *Id.* at *2.

[97] *Id.*

[98] *See, e.g.*, Lore v. Lone Pine Corp., No. L 33606-85, 1986 N.J. Super. LEXIS 1626 (N.J. Super. Ct. Law. Div. Nov. 18, 1986) (originating case from which these discovery control orders derive their name, the court ordered plaintiffs to provide specific documentation regarding each claim for personal injuries and information and reports supporting each individual plaintiff's claim for diminution of property value).

[99] *See* Schneider Nat'l Carriers, Inc. v. Bates, 147 S.W.3d 264, 268 (Tex. 2004) (noting the trial court signed a "Lone Pine" order regarding plaintiffs' nuisance claims).

[100] 347 P.3d 149 (Colo. 2015).

[101] *Id.* at 151.

[102] *Id.*

prejudice.[103] The Colorado Court of Appeals subsequently reversed the "Lone Pine" order and the dismissal order, holding that a "Lone Pine" order was inappropriate for a case that was not "any more complex or cost intensive than an average toxic tort claim."[104] The Colorado Supreme Court agreed with the court of appeals, holding that the Colorado Rules of Civil Procedure do not allow a trial court to use a case management order such as a "Lone Pine" order, and remanded the case to the trial court.[105]

Although the Colorado Supreme Court's decision forecloses the use of "Lone Pine" orders in state court cases in Colorado, the ruling is based on the unique language of Colorado Rule of Civil Procedure 16, which limits a trial court's discretion and has no parallel in Texas. Indeed, defendants have obtained "Lone Pine" orders in other jurisdictions,[106] although the timing of requesting one can affect a court's willingness to grant one.[107] "Lone Pine" orders "appear to be utilized most often in cases involving complicated legal and factual issues in complex mass tort and toxic tort litigation involving multiple parties,"[108] although their future viability may be in question.

5. **Actual Damages.** A plaintiff must prove that the interference resulted in actual damages to the plaintiff.[109]

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[103] *Id.*

[104] *Id.* at 153; Strudley v. Antero Res. Corp., 350 P.3d 874, 882 (Colo. App. 2013).

[105] *See Antero Res. Corp.*, 347 P.3d at 158−59.

[106] *See, e.g.*, Morgan v. Ford Motor Co., No. 06-1080 (JAP), 2007 U.S. Dist. LEXIS 36515, at *39–40 (D.N.J. May 17, 2007) (holding that, in a mass action, "[d]efendants are not entitled to file what amounts to a summary judgment motion without first allowing the party opposing the motion a chance to conduct discovery" and instead mandated that plaintiffs provide only "a simple statement from each plaintiff pursuant to Rule 26(a)(1) identifying the 'nature and extent of injuries suffered'" and also granted a request for the use of bellwether plaintiffs as a case management tool."); Burns v. Universal Crop Protection Alliance, No. 4:07-CV-535, 2007 U.S. Dist. LEXIS 71716, at *3 (E.D. Ark. Sept. 25, 2007) (granting a "Lone Pine" order before commencing discovery).

[107] *See, e.g.*, *Morgan*, 2007 U.S. Dist. LEXIS at *39–40; Simeone v. Girard City Bd. of Educ., 872 N.E.2d 344, 352 (Ohio Ct. App., Trumbull Cnty. 2007) (overturning a trial court's grant of a Lone Pine order as an abuse of discretion because "the timing of the issuance of the 'Lone Pine' order ... [before discovery] effectively and inappropriately supplanted the summary judgment procedure" and shifted the usual burdens of proof onto the non-moving party); Abrams v. Ciba Specialty Chem. Corp., No. 08-68, 2008 U.S. Dist. LEXIS 86487, at *18 (S.D. Ala. Oct. 23, 2008) (declining to issue a Lone Pine order precisely because some discovery had already occurred: "Lone Pine orders are 'pre-discovery' orders. ... [T]he entry of a Lone Pine order is unwarranted [in this case because] the properties of each plaintiff have been tested for the presence of [the chemical substance] DDTr and defendants have been provided with the results.").

[108] Strudley v. Antero Res. Corp., 350 P.3d 874, 879 (Colo. App. 2013) (quoting Roth v. Cabot Oil & Gas Corp., 287 F.R.D. 293 (M.D. Pa. 2012)); *see* Acuna v. Brown & Root, 200 F.3d 335, 339 (5th Cir. 2000) ("Lone Pine orders are designed to handle the complex issues and potential burdens on defendants and the court in mass tort litigation" and such orders "are issued under the wide discretion afforded district judges over the management of discovery under Fed. R. Civ. P. 16.").

[109] In light of the emphasis in *Crosstex* on the "legal injury" (or invasion of a legal right) aspect of nuisance, some may argue that actual damages are no longer an essential element. It is true that there is some authority for the general proposition that actual damages are not required, and nominal damages may be recovered, when a "plaintiff sues for damages for the invasion of a legal right, and fails to show on the trial any actual damage sustained." *See, e.g.*, Ehlert v. Galveston, H. & S.A. Ry. Co., 274 S.W. 172, 174 (Tex. Civ. App.—Galveston 1925, writ dism'd w.o.j.). For example, actual damages are not an essential element for trespass claims. *See, e.g.*, Meyers v. Ford Motor Credit Co., 619 S.W.2d 572, 573 (Tex. Civ. App.—Houston [14th Dist.] 1981, no writ) ("The law is well settled that a trespasser is

The general damages remedies for nuisance are fairly well defined. In general, for a temporary nuisance, the land owner may recover only lost use and enjoyment, *e.g.*, loss of rental value or possibly the cost of restoration.[110] If permanent, the plaintiff may recover lost market value, a value which reflects all property damages, including lost rents expected in the future.[111] The presumed highest and best use of land, against which damages are to measured, is its existing use.[112] Although generally the test in permanent injury is the market value before and after the injury, where there is no isolated event that caused the injury, the proper comparison may be of market value with and without the alleged nuisance.[113] Yet issues remain to be resolved.

One area of dispute is the possibility of damages for "annoyance and discomfiture" or "inconvenience and discomfort." Like many other areas of nuisance law, there is considerable conflicting authority on the scope of these kinds of damages, and it is unclear whether and how these damages might interact with other categories of damages, such as mental anguish.

Texas law is less defined in this area, and some authority even suggests that non-physical "annoyance and discomfiture" is not an injury that allows an award of separate damages.[114] Because annoyance and discomfiture damages were not

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liable to the property owner even though there is no proof of actual damages in any specific amount."). Despite the general proposition above and the Texas Supreme Court's emphasis in *Crosstex* on "legal injury," actual damages are likely still an essential element of a nuisance claim. First, nuisance is derived from trespass on the case, and the court has explained that a trespass on the case plaintiff "must prove actual injury" and is not entitled to nominal damages. *See* Coastal Oil & Gas Corp. v. Garza Energy Trust, 268 S.W.3d 1, 11 (Tex. 2008). Second, without actual damages, a nuisance claim should logically fail to meet the legal injury requirements—that the interference is substantial and unreasonable. *See* Crosstex N. Tex. Pipeline, L.P. v. Gardiner, 505 S.W.3d 580, 596 (Tex. 2016) ("Only a substantial interference that has unreasonable effects constitutes the kind for which the defendant should be liable in damages." (internal quotations and citations omitted)); Trinity Portland Cement Co. v. Horton, 214 S.W. 510, 511 (Tex. Civ. App.—Amarillo 1919, writ dismissed w.o.j.) (stating that nominal damages are not available for nuisance because "[t]he gravamen of the action is the injury"); Thomas W. Merrill, *Trespass, Nuisance, & the Costs of Determining Property Rights*, 14 J. LEGAL STUD. 13, 18 (1985) ("Failure to show actual damages in nuisance . . . usually results in the denial of all relief (because of the failure to satisfy the 'substantial harm' requirement for liability).").

[110] *See Crosstex*, 505 S.W.3d at 610.

[111] *Id.*

[112] *Id.*

[113] *Id.* One issue currently undecided in Texas is the scope of injunctive relief available. In *Lazy R Ranch, L.P. v. ExxonMobil Corp.*, the trial court awarded injunctive relief which would require the defendant to incur substantial remediation costs. 456 S.W.3d 332, 336–37 (Tex. App.—El Paso 2015, pet. granted), *aff'd in part and rev'd in part*, 511 S.W.3d 538 (Tex. 2017). On appeal to the Texas Supreme Court, petitioners and amici argued that the trial court's injunction essentially allowed plaintiffs' to circumvent the fair market value cap for permanent damages. Petitioners asserted that the remediation costs are over 100,000 times the market value of the land. The Texas Supreme Court held the issue was not properly presented to the trial court on summary judgment. 511 S.W.3d at 545–46.

[114] *See* Vestal v. Gulf Oil Corp., 235 S.W.2d 440, 441 (Tex. 1951) (construing case law to state that additional damages are only allowed for "damages to health or physical discomfort"). Rather, in some instances, these damages seem to be treated as a "loss of enjoyment" and are considered part of property damages. *See Bates*, 147 S.W.3d at 269 n.5 (stating *Vestal* held "award for discomfort and loss of enjoyment was not claim for personal injuries"); Brooks v. Chevron USA Inc., No. 13-05-029, 2006 Tex. App. LEXIS 4479, at *22 n.9 (Tex. App.—Corpus Christi May 25, 2006, pet. denied) (citing *Vestal* for the proposition that "symptoms of discomfort or loss of enjoyment are not personal injury damages"); Leyendecker & Assocs., Inc. v. Wechter, 683 S.W.2d 369, 373 (Tex. 1984) (citing *Vestal* for the proposition that "[w]here an injury to realty is permanent, the general measure of damages comprehends and includes the loss of use and enjoyment"). In other cases, "annoyance and

pled in *Crosstex*, the Court there declined to address "the scope of these damages or determine if they are available for either temporary nuisance, permanent nuisance, or both."[115]

Another open question under Texas law is the availability of "stigma" damages. A majority of federal and state courts that have addressed the issue have held that to recover damages for lost market value based on stigma, there must be physical damage to the property.[116] Texas has not squarely addressed the issue of stigma. In *Houston Unlimited, Inc. Metal Processing v. Mel Acres Ranch*, the Texas Supreme Court noted as much, yet left the question open.[117] Texas has disallowed damages for nuisance "based solely on fear, apprehension, or other emotional reaction that results from the lawful operation of industries" in the past, but the availability of stigma damages—and whether physical damage to the property is required—remains an open question.[118]

B. Redefining Private Nuisance in Texas—*Crosstex North Texas Pipeline v. Gardiner*

In *Crosstex*, issued in 2016, the Texas Supreme Court considered a noise nuisance claim involving a natural gas compressor station, seizing on the opportunity to redefine nuisance law. Taking a different tone from prior opinions, the Court's analysis squarely addressed where Texas stands on the three historical "accidents" that have troubled nuisance law for over a century.[119]

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discomfiture" appears to be treated as a separate and distinct kind of damages. *See, e.g.*, Lacy Feed Co. v. Parrish, 517 S.W.2d 845, 851 (Tex. Civ. App.—Waco 1974, writ ref'd n.r.e.) ("[D]amage to the property of the Plaintiff (which includes loss in market value as well as loss of the use and enjoyment of the property) is one element of damage; whereas, damage to the person of the Plaintiff (for personal discomfort, annoyance, and inconvenience) is a separate and distinct, and different element of damage.").

[115] *Crosstex*, 505 S.W.3d at 610 n.21; *see also Likes*, 962 S.W.2d at 504 (noting that a nuisance claim may give rise to these damages); *Schneider*, 147 S.W.3d at 292 n.144 ("[T]he residents do not allege the nuisances here caused personal injuries beyond symptoms of discomfort and annoyance.").

[116] *See In re* Paoli R.R. Yard PCB Litig., 113 F.3d 444, 463 (3d Cir. 1997); Bradley v. Armstrong Rubber Co., 130 F.3d 168, 175–76 (5th Cir. 1997); Adams v. Star Enter., 51 F.3d 417, 424 (4th Cir. 1995); Berry v. Armstrong Rubber Co., 989 F.2d 822, 829 (5th Cir. 1993); Lewis v. Kinder Morgan Se. Terminals LLC, Nos. 2:07cv47KS-MTP, 2:07cv48KS-MTP, 2008 WL 3540174, at *5 (S.D. Miss. Aug. 6, 2008); Mehlenbacher v. Akzo Nobel Salt, Inc., 71 F. Supp. 2d 179, 185–89 (W.D.N.Y. 1999), *rev'd on other grounds*, 216 F.3d 291 (2d Cir. 2000); Mercer v. Rockwell Int'l Corp., 24 F. Supp. 2d 735, 743–45 (W.D. Ky. 1998); Wilson v. Amoco Corp., 33 F. Supp. 2d 981, 986 (D. Wyo. 1998); *In re* W.R. Grace & Co., 346 B.R. 672, 675–77 (Bankr. D. Del. 2006); Smith v. Kan. Gas. Serv. Co., 169 P.3d 1052, 1059 (Kan. 2007); Walker Drug Co. v. La Sal Oil Co., 972 P.2d 1238, 1245–48 (Utah 1998); Chance v. BP Chems., Inc., 670 N.E.2d 985, 993 (Ohio 1996); Adkins v. Thomas Solvent Co., 487 N.W.2d 715, 725 (Mich. 1992).

[117] 443 S.W.3d 820, 822 (Tex. 2014) ("Although some federal and other states' courts have recognized a legal right to recover stigma damages, we have never addressed the issue…. We decline to do so here, however, because even if we recognized such a right, the landowner's evidence of lost market value in this case is not legally sufficient to support the trial court's judgment").

[118] *See* Maranatha Temple, Inc. v. Enter. Prods. Co., 893 S.W.2d 92, 100 (Tex. App.—Houston [1st Dist.] 1994, writ denied); *see also* Rankin v. FPL Energy, LLC, 266 S.W.3d 506, 512 (Tex. App.—Eastland 2008, pet. denied) (holding that where the challenged activity is lawful, nuisance actions are limited to instances in which "the activity results in some invasion of the plaintiff's property and by not allowing recovery for emotional reaction alone.").

[119] *Cf.* Wales Trucking Co. v. Stallcup, 474 S.W.2d 184, 186 (Tex. 1971) (refusing to attempt to give nuisance "any exact or comprehensive definition.")

First, the court distinguished public nuisance from private nuisance.[120] A claim for public nuisance "generally addresses conduct that interferes with 'common public rights' as opposed to private individual rights."[121] Although the Court declined to address public nuisance in full, its short discussion was in line with most modern treatises—public and private nuisance "have nothing in common, except that each causes annoyance or inconvenience."[122] The Court further acknowledged that "a public nuisance may also be a private nuisance," but reaffirmed that "they are two distinct conditions with different requirements and limitations."[123]

Second, the Court examined the varied usage of the term nuisance and held that private nuisance is neither a cause of action nor a description of the defendant's conduct; rather, it is a legal injury related to plaintiff's use and enjoyment of property.[124] Stated another way, nuisance—a particular type of injury to a person's right to use and enjoy property—is only one element of a cause of action and "[a]n injury without wrong does not create a cause of action."[125]

Third, the Court clarified that liability for nuisance is fault-based. Consistent with most Texas decisions in the past few decades, the Court held that an action for nuisance could be based on intentional, negligent, or strict liability conduct.[126] In doing so, it rejected the urging of commentators to limit nuisance to intentional conduct—that is, negligent nuisance should be treated as a normal negligence claim, and strict liability nuisance should be treated as a normal strict liability claim.[127]

Finally, the Texas Supreme Court addressed the difference between private nuisance and trespass. Both involve an interference with an interest in land, and the distinction between the two has been "complex and troublesome."[128] For example, the court "recently referred in passing to trespass claims as those that involve a physical entry . . . as distinguished from nuisance claims in which the

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[120] *Crosstex*, 505 S.W.3d at 591. Most modern Texas cases acknowledge the distinction between public and private nuisance, but courts have at times, usually in dicta, blurred the lines between the two. *Compare* Sciscoe v. Enbridge Gathering (N. Tex.), L.P., No. 07-13-00391-CV, 2015 WL 3463490, at *6 (Tex. App.—Amarillo June 1, 2015, pet. filed) (describing three categories of nuisance as negligent, intentional, and "other inappropriate conduct" and citing statute dealing with public nuisances to describe "other inappropriate conduct") *with, e.g.*, City of Tyler v. Likes, 962 S.W.2d 489, 503 (Tex. 1997) ("Courts have broken actionable nuisance into three classifications: negligent invasion of another's interests; intentional invasion of another's interests; or other conduct . . . which involves an unusual hazard or risk." (internal quotations and citations omitted)).

[121] *Crosstex*, 505 S.W.3d at 591 n.3 (citation omitted).

[122] *Id.* at 590–91 (internal citations omitted).

[123] *Id.* at 591 n.3. The boundaries of public nuisance are beyond the scope of this article, but many of the same principles apply in public nuisance cases. *See, e.g.*, Ortega v. Phan-Tran Prop. Mgmt., LLC, No. 01-15-00676-CV, 2016 WL 3221423, at *4–5 (Tex. App.—Houston [1st Dist.] June 9, 2016, pet. filed) (mem. op.) (holding summary judgment proper on negligent public nuisance claim because there was no evidence that defendant owed plaintiff a duty) [Disclosure: Mr. Stewart is counsel for Phan-Tran in the *Ortega* case.].

[124] *Crosstex*, 505 S.W.3d at 594.

[125] *Id.* at 601 (quoting State v. Brewer, 169 S.W.2d 468, 471 (Tex. 1943)).

[126] *Id.* at 601–02; *see, e.g.*, *Likes*, 962 S.W.2d at 503 (discussing the three categories of actionable nuisance).

[127] *Crosstex*, 505 S.W.3d at 604.

[128] *Id.* at 603 n.17 (internal quotations omitted)

entry . . . is 'not physical.'"[129] However, the modern distinction between the two is that "a trespass involves interference with the plaintiffs' right to *exclusive possession* of their land, while a nuisance involves interference with the plaintiffs' right to *the use and enjoyment* of their land."[130] If "a defendant's conduct interferes with both, the plaintiffs may assert either claim, or both."[131]

C. Fracking as a Nuisance

Surface owners often allege that drilling has contaminated the property's air, water, and soil. Landowners seek retribution for the alleged contamination by asserting a variety of causes of action, including, but not limited to, negligence, gross negligence, trespass, and nuisance.[132] In regard to water, surface owners claim that nearby drilling has turned their water an orange or yellow color, or that their water contains gray sediment.[133] They claim that the water tastes and smells bad, and in some cases has become flammable.[134] Filed complaints contain a long list of chemicals alleged to have been found in their water wells: benzene, arsenic, lead, iron, potassium, zinc, ethyl benzene, toluene, barium, and even methane gas.[135]

With regard to the methane gas, according to the petitions, fracking allegedly releases underground methane gas, and the gas migrates to groundwater aquifers and gets into the landowners' water wells.[136] The typical allegation is that methane

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[129] *Id.* (quoting Gilbert Wheeler Inc. v. Enbridge Pipelines (E. Tex.), L.P., 449 S.W.3d 474, 480 (Tex. 2014)).

[130] *Id*. One persistent issue courts have struggled with is whether migratory microscopic particles are actionable in trespass, nuisance, or both. *See* HARPER § 1.23, at 103 & n.44 (stating that "with the increase in scientific knowledge and methods many invasions are perceived today as physical that would once have supported an action for nuisance only" and citing conflicting results). The Texas Supreme Court has not definitely weighed in on this subject. *See Schneider*, 147 S.W.3d at 292 (sidestepping the issue by "[a]ssuming that entry of photons, particles, or sound waves can constitute a trespass . . . ."); *see also* Stevenson v. E.I. Dupont de Nemours & Co., 327 F.3d 400, 405–06 (5th Cir. 2003) (making an *Erie* guess that "Texas law would permit recovery for airborne particulates" in trespass). One Texas appellate court recently held that "a trespass claim under Texas law may be premised upon the entry onto property of airborne particulates." Sciscoe v. Enbridge Gathering (N. Tex.), L.P., 519 S.W.3d 171, 185 (Tex. App.—Amarillo 2015), *rev'd sub nom.* Town of Dish v. Atmos Energy Corp., 519 S.W.3d 605 (Tex. 2017).

[131] *Crosstex*, 505 S.W.3d at 603 n.17.

[132] Citations are provided as examples of complaints filed. A number of these cases have been dismissed and subsequent history is not included. *See generally* Amended Complaint, Harris v. Devon Energy Prod., 4:10-CV-708 (E.D. Tex. Apr. 8, 2011); Complaint, Scoma v. Chesapeake Energy Corp., No. 3:10-cv-01385 (N.D. Tex. Aug. 11, 2010); Amended Complaint, Fiorentino v. Cabot Oil & Gas Corp., No. 3:09-cv-02284 (M.D. Pa. May 17, 2010), 2010 WL 2070478; Petition, Lipsky v. Range Res., No. CV11-0798 (Tex. Dist. Ct., Parker Cnty., June 20, 2011); Complaint, Becka v. Antero Res., No. 2:11-CV-01040 (W.D. Penn. dismissed Sept. 24, 2012); Complaint, Dillon v. Antero Res., No. 2:11-CV-01038 (W.D. Penn. dismissed Sept. 28, 2012); Complaint, Boggs v. Landmark 4, LLC, No. 1:12-CV-00614 (N.D. Ohio Mar. 12, 2012), 2012 WL 960913.

[133] *See Scoma* Complaint, *supra* note 132; *Harris* Amended Complaint, *supra* note 132.

[134] *See Scoma* Complaint, *supra* note 132; *Fiorentino* Amended Complaint, *supra* note 132.

[135] *See Scoma* Complaint, *supra* note 132; *Fiorentino* Amended Complaint, *supra* note 132; *see also* Casey Junkins, "Firm Denies Methane Liability," *Herald Star* (Apr. 17, 2012), http://www.heraldstaronline.com/page/content.detail/id/572600/Firm-denies-methane-liability.html?nav=5010.

[136] *See Fiorentino* Amended Complaint, *supra* note 132; *see also* Bryan Walsh, "Another Fracking Mess for the Shale-Gas Industry," *Time* (May 9, 2011).

escapes the wells via home faucets, creating a fire hazard.[137] Landowners contend that other chemicals, like benzene, are entering the water supply via above-ground contamination, *e.g.*, from spills and improper disposal techniques.[138] Landowners claim that careless treatment of fracking fluids at the surface—the mixture of water, sand, and various chemicals that facilitates the breaking of the rock layer (shale) in which minerals are located—causes chemicals to enter groundwater aquifers and water wells from the surface.[139] Soil contamination claims are similar: when the companies spill fracking fluid, produced water, and/or oil, the soil becomes contaminated according to the allegations.[140]

In cases alleging air pollution, landowners contend that fumes from the diesel-powered engines are causing them to inhale large quantities of chemicals, like nitrogen oxides and carbon monoxide, on a daily basis.[141] Additionally, landowners claim that fracking creates particulate matter, like smog and dust. Landowners have asserted claims for assault, battery, and intentional infliction of emotional distress, because the "severe air pollution" they allege caused physical distress and injuries like tremors, confusion, irregular heartbeat, nosebleeds, headaches, and rashes. In the *Boggs* case from Ohio, plaintiffs are seeking court-established medical monitoring due to the alleged risk to their health posed by fracking.[142]

1. Noise, Odors, and Light

Plaintiffs often bring nuisance claims alongside contamination allegations. Surface owners aver that unpleasant odors, the operation of the drilling equipment, and the constantly shining lights interfere with the use and enjoyment of their property.[143] These claims usually relate to oil and gas development generally rather than fracking specifically. They allege that the production activities are abnormal, out of place in their current locations, and create harmful living

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[137] The Internet is littered with home movies of people setting their water on fire to demonstrate the combustibility of tap water. Notably, the veracity of these videos has been called into question by oil and gas companies, sometimes resulting in counterclaims for defamation. *See* Order Denying Plaintiffs' Sec. 27 Anti-Slapp Motion to Dismiss Range's Counterclaims, Lipsky v. Range Res., No. CV11-0798 (Tex. Dist. Ct., Parker Cnty., Feb. 16, 2012) (denying Plaintiffs' motion to dismiss counterclaims by Range alleging that a water-on-fire video released by Plaintiffs' to the news media constituted a conspiracy to defame Range).

[138] *Scoma* Complaint, *supra* note 132; Complaint, Berish v. Sw. Energy Prod. Co., No. 3:10-cv-01981 (M.D. Pa. Sept. 14, 2010), 2010 WL 4230599; Complaint, Mitchell v. EnCana Oil & Gas, No. 3:10-cv-02555 (N.D. Tex. dismissed Nov. 14, 2011).

[139] *Scoma* Complaint, *supra* note 132; *Berish* Complaint, *supra* note 138; *Mitchell* Complaint, *supra* note 138.

[140] Complaint, Rine v. Chesapeake Appalachia, LLC, No. 5:11-cv-00004-FPS (N.D. W. Va. Jan. 6, 2011); Plaintiff's Second Amended Petition, Ruggiero v. Aruba Petroleum, Inc., No. CV-10-10-801 (Tex. Dist. Ct., Wise Cnty. May 11, 2011).

[141] Plaintiff's Original Petition, Parr v. Aruba Petroleum, Inc., No. 2011-01650-E (Tex. Dist. Ct., Dallas Cnty. Mar. 18, 2011); *Boggs* Complaint, *supra* note 132; *see also* John Colson, "Class Action Suit Filed Against Antero Resources," *Glenwood Spring Post Independent* (July 21, 2011) (describing a class action filed in Colorado state court alleging health consequences suffered as a result of nearby drilling). A similar lawsuit was filed against Antero in March 2011. Ryan Wyrick, "Company Dumping in Eagle County Slapped with Lawsuit," *Vail Daily* (Aug. 21, 2011).

[142] *Boggs* Complaint, *supra* note 132.

[143] Petition, Dow v. Atmos Energy Corp., No. 2011-30097-211 (Tex. Dist. Ct., Denton Cnty., Feb. 28, 2011); Petition, Sciscoe v. Atmos Energy Corp., No. 2011-70084-431 (Tex. Dist. Ct., Denton Cnty., Feb. 28, 2011).

conditions. As drilling activities occur more often in populous areas, the frequency of nuisance claims may also increase.

2. Earthquakes

A few plaintiffs have alleged that fracking operations have caused or contributed to man-made earthquakes that damaged their property. The petitions allege that wastewater disposal injection wells used to dispose of flowback fluids cause seismic events.[144] Surface owners seek property damages under various causes of action, including nuisance, strict liability, negligence, and trespass.

3. Personal Injury Lawsuits

Ironically, the salutary embrace by numerous states of frack-chemical disclosure laws is regarded by one commentator as likely to promote not only groundwater contamination suits, but also create what he describes as "pressure points in benzene litigation."[145] However, to date, no plaintiff has been successful in persuading a judge or a jury that there is any link between any personal injury and hydraulic fracturing.[146]

D. Some Defenses in the Nuisance Context

While a number of defenses to other torts apply to nuisance, two particular defensive theories have recently been litigated, with mixed results. First, limitations arguments continue to be a troublesome area, particularly for nuisance cases in Texas. Second, where a landowner has leased minerals under the land in dispute, a lessee recently successfully argued that the landowners/lessor were quasi-estopped from bringing their claim.

The limitations period for a private nuisance claim in Texas is two years.[147] After the limitations period expires, any nuisance claim is barred.[148] However, determining the accrual date has proved troublesome. The accrual date depends on whether a nuisance is "temporary" or "permanent"—"[a] permanent nuisance claim accrues when injury *first* occurs or is discovered; a temporary nuisance claim accrues *anew* upon each injury."[149] This distinction[150] has resulted in a body

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[144] Complaint, Sheatsley v. Chesapeake Operating, Inc., No. 4:11-cv-00353 (E.D. Ark. Apr. 22, 2011); Second Amended Complaint, Hearn v. BHP Billiton Petroluem, No. 4:11-cv-00474 (E.D. Ark. Apr. 9, 2013); Petition, Finn v. EOG Res., No. C2013-00343 (Tex. Dist. Ct., Johnson Cnty., July 30, 2013).

[145] Joseph M. Schreiber, "Frac-fluid recipes threaten to become pressure points in benzene litigation," *Oil & Gas Journal* (June 4, 2012), http://www.ogj.com/articles/print/vol-110/issue-06/general-interest/frac-fluid-recipes-threaten.html.

[146] One personal injury case recently concluded in Texas. *See* Jury Charge, Parr v. Aruba Petroleum, Inc., No. 11-01650-E (Tex. Dist. Ct., Dallas Cnty., Apr. 22, 2014). This case was described in media reports as "one of the first trials seeking to hold a company liable for medical problems allegedly linked to chemicals used in fracking." Jess Davis, "Texas Family Claims $9M For Fracking-Related Illnesses," *Law360* (Apr. 8, 2014), http://www.law360.com/articles/526326/texas-family-claims-9m-for-fracking-related-illnesses. The case, however, had nothing to do with "chemicals used in fracking"—rather, plaintiffs' personal injury claims were based on the alleged harmful effects of sounds, lights, and smells from the drilling of gas wells, the production of gas, and the storage of condensate. The plaintiffs' expert testified that emissions from condensate storage tanks were the offending emissions.

[147] *See Schneider*, 147 S.W.3d at 270.

[148] *Id.*

[149] *Id.*

of case law that "has no standard of reference" and is full of irreconcilable precedents.[151]

In *Schneider*, the Texas Supreme Court stated that the distinction between permanent and temporary nuisance lies in whether the case involves "an activity of such a character and existing under such circumstances that it will be presumed to continue indefinitely."[152] Further complicating things, the Texas Supreme Court recently reformulated the distinction for injuries to real property so that:

- "An injury to real property is considered permanent if (a) it cannot be repaired, fixed, or restored, or (b) even though the injury can be repaired, fixed, or restored, it is substantially certain that the injury will repeatedly, continually, and regularly recur, such that future injury can be reasonably evaluated."
- "[A]n injury to real property is considered temporary if (a) it can be repaired, fixed, or restored, and (b) any anticipated recurrence would be only occasional, irregular, intermittent, and not reasonably predictable, such that future injury could not be estimated with reasonable certainty."[153]

Moreover, for some nuisance cases, the problem of a "new" nuisance arises, such as where the activity changes in character during the limitations period. In some instances, what might to some have seemed a "permanent" nuisance barred by limitations has been characterized as a new "temporary" nuisance because "an old nuisance does not excuse a new and different one."[154] Particularly relevant to defendants seeking to bar claims based on limitations, an accrual date based on "subjective criteria like smell and sound"—as opposed to measurable, objective criteria (such as chemical levels in the air)—may be left to the jury.[155]

Finally, a recent Texas case suggests a potential defense where a landowner complains of his lessee's actions, and those actions are taken pursuant to the parties' lease. In *Titan Operating LLC v. Marsden*, the surface owners brought a lawsuit against Titan claiming that noise from drilling, fumes from diesel engines, and lights from the well site that "lit up [the] whole house like a Christmas tree" constituted a nuisance.[156] The jury awarded $36,000. The court of appeals reversed and rendered because, as a matter of law, plaintiffs were precluded from "accepting the benefits of their oil and gas lease . . . and later maintaining a

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[150] This distinction has been called "one of the oldest and most complex in Texas law." *Id.* at 274–75.

[151] *Id.*; *see also Crosstex*, 505 S.W.3d at 587 n.1 (noting the same in its discussion of nuisance as "a morass").

[152] *Schneider*, 147 S.W.3d at 272.

[153] Gilbert Wheeler, Inc. v. Enbridge Pipelines (E. Tex.), L.P., 449 S.W.3d 474, 480 (Tex. 2014).

[154] *Schneider*, 147 S.W.3d at 280; *see* Atlas Chem. Indus., Inc. v. Anderson, 524 S.W.2d 681, 683 (Tex. 1975) (new emissions to new property due to new natural forces—but same plaintiff—from plant operating for over 40 years).

[155] Nat. Gas Pipeline Co. of Am. v. Justiss, 397 S.W.3d 150, 155 (Tex. 2012) ("The point at which an odor moves from unpleasant to insufferable or when noise grows from annoying to intolerable might be difficult to ascertain, but the practical judgment of an intelligent jury is equal to the task." (internal quotations, citations, and alterations omitted)).

[156] Titan Operating, LLC v. Marsden, No. 02-14-00303-CV, 2015 WL 5727573, at *3 (Tex. App.—Fort Worth Aug. 27, 2015, pet. denied) (mem. op., not designated for publication).

nuisance suit against Titan for acts that the lease . . . contemplated or authorized."[157]

III. CONCLUSION

As the case law illustrates, nuisance has been and remains an amorphous doctrine. Despite much recent litigation, a host of questions remain on issues ranging from what conduct supports a nuisance claim to what damages are recoverable. Numerous nuisance cases against energy companies are still pending in various stages of trial and appeal. As the centuries-old doctrine continues to evolve, oil and gas drilling and production activities are today at ground zero in this process.

[157] *Id.* at *1; *see also* Grimes v. Goodman Drilling Co., 216 S.W. 202, 204 (Tex. Civ. App.—Fort Worth 1919, writ dism'd) (affirming that plaintiff was not "entitled to an abatement of the nuisance" created by the drilling of a well on his property by defendants as plaintiff "purchased the premises burdened with the terms of the lease, he is in no position to complain of the conditions produced by [defendants], such as are usual and customary during the drilling of an oil well").

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Part III

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