Oil and Gas Assets

A Practical Guidance® Practice Note by Ira L. Herman, Blank Rome LLP

Ira L. Herman
Blank Rome LLP

This practice note discusses the economic and political forces impacting domestic oil and gas prices and production and how such assets are dealt with, when there exists financial distress, under the U.S. bankruptcy laws. The price of crude oil, like the price of virtually all commodities, moves up when supplies are "tight" and down in times of excess capacity. When a mismatch exists between supply and demand, the markets are expected to self-correct. Excess supply should result in price and production cuts, while excess demand should be met with price and production increases.

In 2021, when we last updated this note, the price of crude oil and natural gas were "stubbornly depressed from the more robust prices levels seen a few short years ago." Now, the pendulum has swung in the opposite direction. Instead of excess supply, there are limitations on supply and increased demand, as economies around the globe have reopened in the aftermath of the pandemic. Additionally, and unsurprisingly, the war in Europe has had both a direct and an indirect impact on domestic and international oil and gas prices. Among the direct effects—the sanctions that have been imposed by the Western powers and Russia's retaliation—restricting supply. Simply stated, hydrocarbons are being used as an economic weapon. Indirectly, war by its very nature is inflationary, and this war also has served to disrupt the supply chain, including with respect to global food distribution. Thus, the war in Europe has exacerbated the inflationary pressures already affecting the global economy and central banks have reacted by raising interest rates to slow inflation, giving rise to economic uncertainty and fears of an impending global economic recession. In previous cycles, when prices for oil and gas have been high, the maxim was almost always "drill baby drill" but that does not appear to be happening in 2022, as the lessons of the past have informed industry participants to be cautious as they are concerned that demand will fall upon the advent of a recession.

This practice note addresses topics, including:

- Industry Background – Upstream, Midstream, and Downstream
- Supply and Demand – Creating the Current High Price Business Environment
- A Capital-Intensive Business
- Funding E&P Costs by Transferring an Interest
- What Happens in Bankruptcy?

For related content, see Oil and Gas Purchase Agreements and Distressed Investing in Upstream Oil and Gas.

Industry Background – Upstream, Midstream, and Downstream

The oil and gas industry generally is said to be divided into three segments: upstream, midstream, and downstream. The upstream segment includes companies that engage in the exploration for and production (E&P) of oil and gas. Businesses in the upstream sector find and produce crude oil, natural gas, and shale gas. To find and produce hydrocarbons, upstream companies require machinery, equipment, exploration services, and geophysical services. Collectively, the providers of these goods and services are known in the business as oil field service providers.

The midstream sector processes, stores, and engages in the wholesale marketing of hydrocarbons, including crude oil, natural gas, and gas liquids. Transportation companies in this sector include pipeline companies, rail car operators, barge operators, oil tanker owners, and trucking companies. Storage may include tank farms and the like.

Oil and gas operations that take place after the production phase through to the point of sale are said to be downstream. Downstream operations can include refining crude oil and distributing the by-products down to the retail level. By-products include gasoline, natural gas liquids, diesel, and a variety of other energy sources.

Relationship between Prices, Producers, and Service Companies

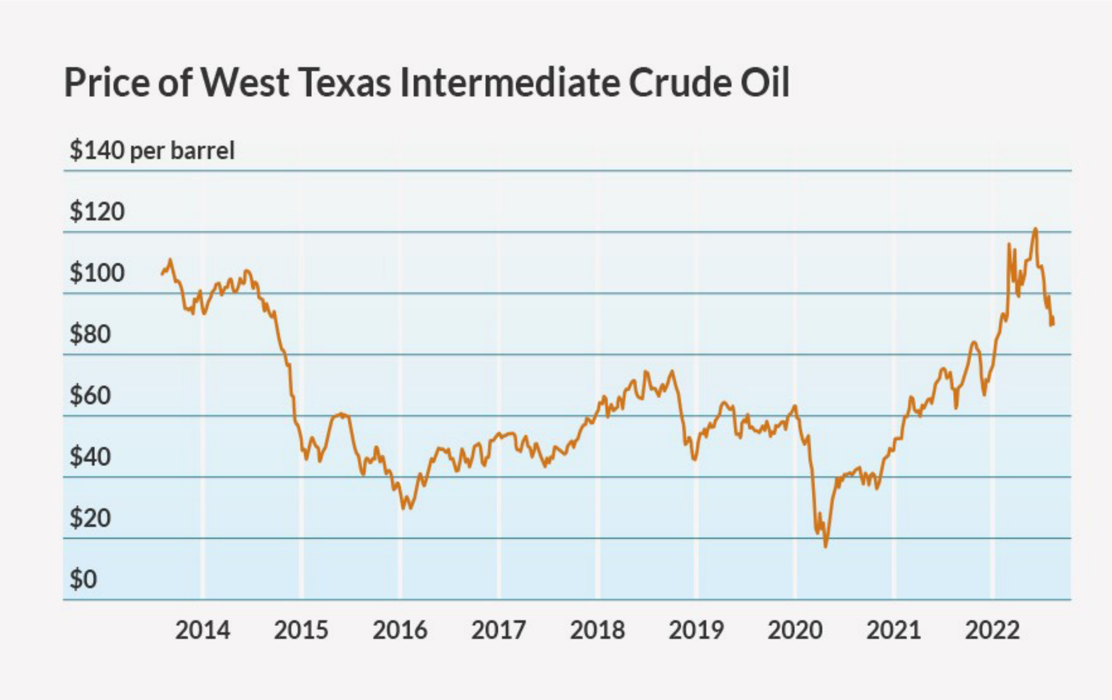
During a run-up in commodity prices, upstream companies generally will increase exploration and the development of hydrocarbon, resulting in strong demand for the equipment used in the production of oil and gas. Businesses in this space include manufacturers of rigs, pipes, casings, etc. Weaker commodity prices generally lead to reduced investment in exploration and production, hurting producers of oil field services equipment, as producers reduce costs to preserve cash and protect their balance sheets.

Similarly, oil field service providers who engage in tasks including drilling oil and gas wells; surveying; running, cutting, and pulling casings; chemically treating wells, and disposing of wastewater and other production waste, are similarly impacted by oil and gas prices. Rising oil and gas prices typically result in increased demand for oil field industry services and the ability of firms in the space to charge premium prices. The number of oil and gas drilling contracts generally rise with prices, as previously unprofitable sites will become profitable, and, therefore, more attractive to producers. In contrast, and perhaps, quite obviously, demand for oil field services falls, as do the prices for such services, when oil and gas prices are low.

Supply and Demand – Creating the Current High Price Business Environment

Early in 2021, the failure of the markets to self-correct and rebalance supply with demand to stabilize was blamed on the confluence of several obvious and less obvious domestic and international economic and geopolitical drivers. The collective impact of this failure to rebalance served to depress prices. Since early 2021, there has been a sea change, and not only are oil and gas prices no longer depressed, but they are at or near record levels.

In April 2020, U.S. crude prices amazingly fell into negative territory and Brent dropped below $20 per barrel, as demand collapsed due to the COVID-19 pandemic, while a price war between Saudi Arabia and Russia resulted in production that flooded the market. In the second half of 2022, the situation that existed in 2020 has been turned on its head. About the only thing that has not changed are the buzz words applicable to the energy exploration and production sector, as in 2020, the words buzz words still are—"disruption and uncertainty." An August 15, 2022, NY Times article made this point, as follows—"Energy prices can spike as easily as they can plummet, unexpectedly and suddenly. China, where Covid-19 lockdowns remain widespread, will eventually reopen its cities to more commerce and traffic, increasing demand. Withdrawals of oil from the U.S. Strategic Petroleum Reserve will end in November, and it will need to be refilled. And a single unexpected event—say, a hurricane flooding the Houston Ship Channel and taking several Gulf of Mexico refineries out of commission for weeks or even months—could send fuel prices soaring. That sort of catastrophe could send tidal waves through the American and even global economy since energy prices are fundamental to the prices of everything that is shipped and produced, whether it be grain or building supplies."



Visualization of "Price of West Texas Intermediate Crude Oil"

Source: FactSet – By The New York Times, August 15, 2002

Other factors that could push prices down prices near term include:

- Iran agreeing to a new nuclear agreement, potentially adding at least one million barrels a day of Iranian petroleum to the market
- A continuing increase in interest rates has many investors and economists predicting a recession—and a reduction in demand—even though unemployment is low
- The recently enacted Inflation Reduction Act, is a game changer and has been touted by its supporters as a "climate change bill"

The Inflation Reduction Act includes the single biggest climate investment in U.S. history with the stated goal of putting the U.S. on a path to roughly 40% emissions reduction by 2030. Below is a summary of these investments:

- The law provides direct consumer incentives to buy energy-efficient and electric appliances, clean vehicles, rooftop solar systems, and invests in home energy efficiency. These investments include:
  - $9 billion in consumer home energy rebate programs to electrify home appliances and for energy-efficient retrofits
  - 10 years of consumer tax credits to make homes energy-efficient and run-on clean energy, incentivizing heat pumps, rooftop solar, and electric HVAC and water heaters
  - $4,000 consumer tax credit for lower/middle income individuals to buy used clean vehicles
  - Up to $7,500 in tax credits to buy new clean vehicles
  - $1 billion grant program to make affordable housing more energy-efficient
- The law includes over $60 billion to maintain clean energy manufacturing in the U.S. across the full supply chain of clean energy and transportation technologies. These provisions include:
  - $30 billion in production tax credits to accelerate U.S. manufacturing of solar panels, wind turbines, batteries, and critical minerals processing
  - $10 billion investment tax credit to build clean technology manufacturing facilities, like facilities that make electric vehicles, wind turbines, and solar panels
  - $500 million in the Defense Production Act for heat pumps and critical minerals processing
  - $2 billion in grants to retool existing auto manufacturing facilities to manufacture clean vehicles
  - Up to $20 billion in loans to build new clean vehicle manufacturing facilities across the country

- $2 billion for National Labs to accelerate breakthrough energy research

- The law targets investments designed to reduce emissions in every sector of the economy, including electricity production, transportation, industrial manufacturing, buildings, and agriculture. The investments include:
  - Tax credits for clean sources of electricity and energy storage and roughly $30 billion in targeted grant and loan programs for states and electric utilities to accelerate the transition to clean electricity
  - Tax credits and grants for clean fuels and clean commercial vehicles to reduce emissions from all parts of the transportation sector
  - Grants and tax credits to reduce emissions from industrial manufacturing processes, including almost $6 billion for a new advanced industrial facilities
  - Deployment program to reduce emissions from the largest industrial emitters like chemical, steel, and cement plants
  - Over $9 billion for federal procurement of American-made clean technologies to create a stable market for clean products, including $3 billion for the U.S. Postal Service to purchase zero-emission vehicles
  - $27 billion clean energy technology accelerator to support deployment of technologies to reduce emissions, especially in disadvantaged communities
  - A Methane Emissions Reduction Program to reduce the leaks from the production and distribution of natural gas
- This package includes over $60 billion in environmental justice priorities to drive investments into disadvantaged communities, including:
  - The Environmental and Climate Justice Block Grants, funded at $3 billion, invest in community-led projects to address disproportionate environmental and public health harms related to pollution and climate change
  - The Neighborhood Access and Equity Grants, funded at $3 billion, support neighborhood equity, safety, and affordable transportation access
  - Grants to Reduce Air Pollution at Ports, funded at $3 billion, support the purchase and installation of zero-emission equipment and technology at ports
  - $1 billion for clean heavy-duty vehicles, like school and transit buses and garbage trucks
- The law provides for significant investment in clean energy development in rural communities, including:
  - More than $20 billion to support climate-smart agriculture practices
  - $5 billion in grants to support fire resilient forests, forest conservation, and urban tree planting
  - Tax credits and grants to support the domestic production of biofuels, and to build the infrastructure needed for sustainable aviation fuel and other biofuels
  - $2.6 billion in grants to conserve and restore coastal habitats and protect communities that depend on those habitats
- Although the law has been touted as a historic climate change bill, some climate activists are upset at provisions benefitting the fossil fuel industry. Yet, some of the fossil fuel provisions are viewed by industry experts as being punitive, as they attempt to get fossil fuel companies to change certain practices. Some of the fossil fuel provisions include:
  - Federal lands and offshore waters to be developed for renewable energy must also be made available for oil and gas drilling
  - Incentives toward installation of efficiency upgrades and carbon capture solutions
  - Concessions that could streamline a West Virginia gas pipeline and ease permitting for new energy projects
  - New fees for natural gas extraction and methane leaks, and Superfund taxes on crude oil and its related products (but also incentives to oil companies that reduce methane leaks)
  - o New funds for air pollution monitoring, including for methane
  - A new tax on stock buybacks which is intended to encourage companies (not just oil companies) to invest cash back into their businesses

Thus, even though the fossil fuel provisions were a mixed bag for the oil industry, they are finding general support from the industry. ExxonMobil CEO Darren Woods called the bill “a step in the right direction” in part because “This policy could include regular and predictable lease sales, as well as streamlined regulatory approvals and support for infrastructure such as pipelines.”

The biggest winners from this legislation appear to be:

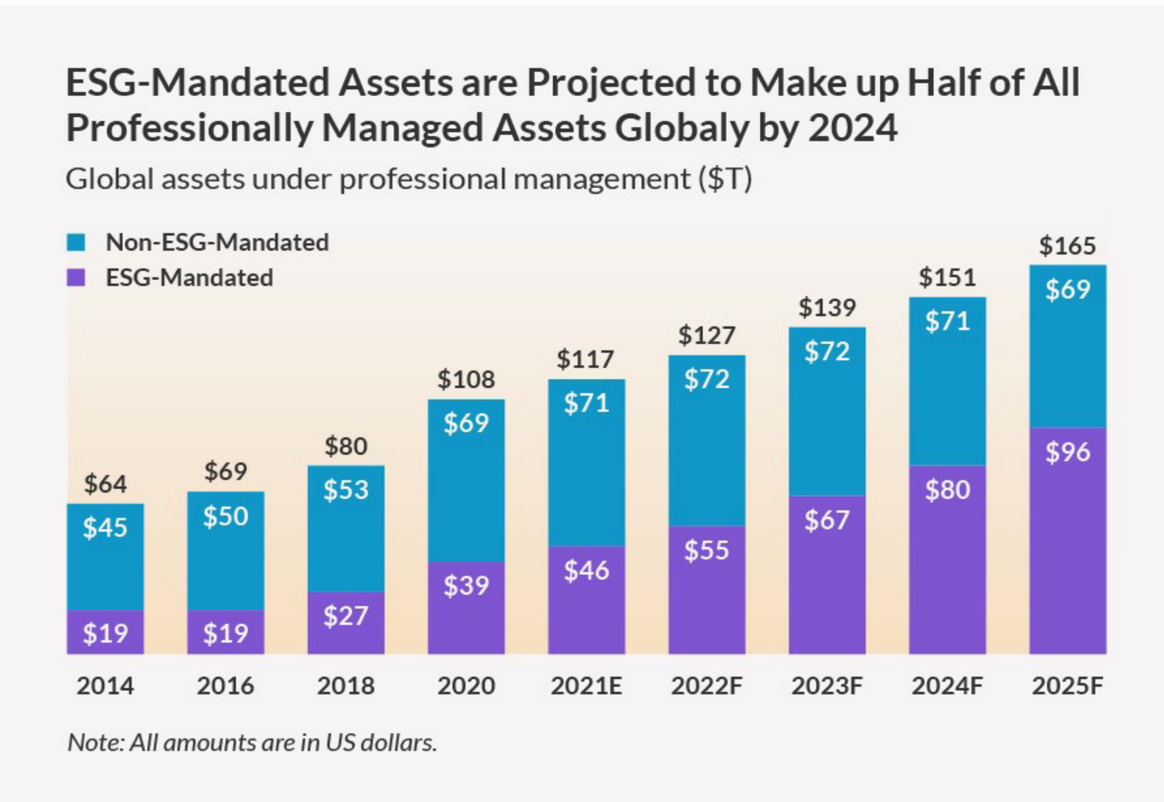
- Wind and solar companies
- Utilities transitioning toward renewable energy
- Electric vehicle companies
- Companies that extract and process materials like lithium

Within the oil and gas industry, the benefits skew toward the biggest companies since they can (1) afford to invest in new carbon and methane capture technologies and (2) spend billions developing new offshore leases. Smaller oil and gas companies may simply find an increase in their cost of doing business.

The biggest losers from this legislation appear to be:

- Businesses that have relied (or intend to rely) heavily on stock buybacks
- The coal industry, as incentives are skewed strongly in favor of the expansion of renewable power capacity, that will likely further marginalize coal as an energy source (Natural gas, on the other hand, should continue to farewell as a source of power, as its use meshes well with new renewable capacity.)

Environmental, social, and governance (ESG)-themed investing has been accelerating. As recently as 2018, the largest amount of sustainable investing assets was in Europe, totaling US$14.1 trillion, followed by the United States with US$12 trillion. Global Sustainable Investment Alliance (GSIA), *2018 Global Sustainable Investment Review*, April 1, 2019. From 2014 to the beginning of 2018, assets under management with an ESG mandate held by investors grew at a four-year CAGR of 16% in the United States, compared with 6% in Europe. It is anticipated that the anticipated ESG-themed investing will show continued accelerated growth, especially in the U.S with the enactment of the Inflation Reduction Act. The chart below illustrates this point:



Visualization of "ESG-Mandated Assets are Projected to Make up Half of All Professionally Managed Assets Globally by 2024"

Note: All amounts are in U.S. dollars.

Source: Proportion of ESG-mandated data through 2020 from Global Sustainable Investment Alliance; DCFS analysis through 2025.

Deloitte Insights – deloitte.com/insights

A Capital-Intensive Business

Fundamentally, E&P is a capital-intensive business. The equipment needed is expensive and not all wells drilled are economically viable. As a result, E&P companies must raise large amounts of capital in order to turn a promising hydrocarbon discovery into a producing asset. One obvious way to cover the costs of exploration is to use the revenue generated by existing production. Alternatively (or in the absence of an income stream generated by production), industry participants have divided producing assets into numerous fragments, all capable of being monetized to fund E&P Finally, an E&P company may fund its capital needs by borrowing from an institutional or other lender, often pursuant to a reserve-based revolving credit facility.

Funding E&P Costs by Transferring an Interest

Working Interests and Royalty Interests

A mineral rights owner is one who owns oil and gas deposits under the surface, including the right to explore, drill, and produce those deposits. However, many mineral interest owners are not in the business of exploration and production, as they lack the expertise and capital to explore and produce.

In order to monetize that interest, the mineral interest owner typically signs an oil and gas lease with an E&P company, giving the E&P company the right to explore and develop the subsurface in exchange for the obligation to pay the mineral rights owner a non-cost-bearing share of the income from the production, which is known as a royalty interest. As a royalty interest holder, the mineral rights owner is entitled to a stated portion of the gross production, if any, but has no right to enter the land and extract minerals, but also does not share in any of the exploration and development costs.

By virtue of the execution of the oil and gas lease, the E&P company becomes the 100% working interest owner and also obtains royalty interest in the amount conveyed by the mineral interest owner under the oil and gas lease. In contrast to a royalty interest, a working interest holder will have the right to explore and develop the minerals along with the obligation to pay the costs associated with exploration and development. A working interest in a property does not exist in perpetuity but is governed by the terms of the oil and gas lease. There may be a number of reasons for termination, including (1) the failure to meet specified minimum production requirements, (2) the end of the productive life of a well, and (3) an agreement by the parties to terminate on a certain date.

The working interest holder may use portions of its interest to finance production, either by selling part of its working interest to third parties, using a fractional part of its net revenue as collateral for a loan, or by selling a portion of the income to be generated by production in connection with the working interest. An example of such an interest is the overriding royalty interest (ORRI). Unlike a landowner's royalty interest, ORRIs are typically carved-out from a working interest. As a general proposition, there are two types of ORRIs: (1) the perpetual ORRI, which lasts for the life of the lease between the working interest holder and the mineral rights holder; and (2) the term ORRI, which is limited in duration, either until a specified volume of production is reached or a stated value of production is reached. Similar to ORRIs are net profit interests (NPIs). An NPI is carved-out of a working interest, much like an ORRI; however, the NPI holder is only paid out of the profits earned from production over a contractually agreed-upon time span (in other words, ORRIs are paid as a percentage of gross revenue/production and NPIs out of net profits).

Joint Operating Agreements

Joint operating agreements (JOAs) are common in the oil and gas industry because they allow multiple co-owners to cooperate in the exploration, development, and production of oil and gas in certain described property under the direction of a single operator. A JOA typically governs the relationship among working interest co-owners, who own undivided fractional oil and gas leasehold interests, and the operator, who is often simply the investor with the largest working interest. The JOA will, among other purposes, identify the interests of the parties in the leases and property, commit the parties to participate in operations on the contract area (and provide procedures for resolving disputes), provide for sharing expenses and allocate liability with respect to joint operations, and control the rights of the parties in the production from the contract area.

Farmout Agreements

Another type of agreement typical in the oil and gas industry is the farmout agreement. Farmouts are often used when a lease is expiring and the lessor does not have capital to drill. Although farmouts can take a myriad of forms, a farmout agreement typically provides for a working interest owner to assign a working interest to a party known as a farmee in exchange for certain contractually agreed-upon services. Typically, these services include drilling a well in a certain location to a certain depth within a specified time frame. After the contractually agreed-upon services have been completed, the farmee is said to have "earned" an assignment, subject to the reservation of an overriding royalty interest in favor of the working interest owner.

This ORRI is usually said to be a "convertible override." This means that upon payout, which is the point where the drilling costs have been recouped from production from the well, the farmee can elect to convert this override into a portion of the working interest. The decision whether to convert or not depends on whether the farmee wishes to join in production costs in exchange for the possibility of a larger return. When a farmee is comfortable with the project costs and production from the well it has drilled, the farmee will generally convert its override interest into a working interest.

Farmout agreements tend to be highly negotiated documents, although they also generally include standard terminology, as the provisions of all farmout agreements generally address several crucial issues. These issues include the duty imposed (i.e., whether the farmee has an obligation or an option to drill, etc.), the obligation that must be met in order for the farmee to earn its target interest in the property, the interest in the property to be earned, the number of wells to be committed to the farmout agreement (can be one or more), and the timing of issuance of the assignment of farmout acreage to the farmee (generally after completion of the farmee's obligations to drill, etc.).

Revolving Credit Facilities / Reserve-Based Lending

An E&P company can rely on a reserve-based revolving credit facility (RBL facility) for its working capital needs and to fund its exploration and development programs. However, this type of financing is only available where revenue is already being generated by prior production. Loan availability under an RBL facility is permitted pursuant to a borrowing base formula set by the lender to the industry participant, primarily in consideration of the value of the participant's proved oil and gas reserves. The value of such reserves is determined by reference to a "price deck" set by the lender, under the terms of the RBL lending agreement.

Although RBL facilities typically require a lender to consider the value of the borrower's proved reserves in setting the borrowing base, an RBL lender is generally also permitted to consider such other information as it deems appropriate at its sole discretion. In short, the borrowing base is whatever the lender says it is.

RBL facilities typically require scheduled redeterminations of the borrowing base on a semiannual basis, once in the spring and once in the fall. Additionally, a lender is generally provided the right to a single special redetermination between scheduled redeterminations. Finally, incurring additional long-term debt often triggers automatic reductions to the borrowing base (often a $0.25 reduction for each $1.00 of additional debt incurred), and the RBL lender is often permitted a special redetermination in connection with any termination of commodity hedging contracts. Despite the forgoing, says McNulty, "it is important to understand that there are many lending facilities in the market now that service their debt payments, even as the asset valuation falls below credit thresholds."

In times of steep declines in commodity prices, many E&P companies will find the availability for additional borrowings under an RBL facility reduced, in some instances, to a level below the aggregate principal amount of loans outstanding, resulting in a borrowing base deficiency. Once a borrowing base deficiency has occurred, most RBL facilities will provide the borrower the option to add additional collateral with a value equal at least to the deficiency amount or to pay down the outstanding loans in an aggregate amount equal to the deficiency in a single payment or in equal installments of three to six monthly payments.

In a typical reserves-based financing, substantially all of the collateral has already been pledged to the lender as collateral, which leaves the borrower with the sole option of paying down the debt. Choosing to repay a deficiency amount in installments gives the borrower a short window of time to raise capital, including by selling properties or securing additional credit through a junior lien or subordinated debt, in order to avoid an event of default under its RBL facility. An impending RBL default is one of many reasons an E&P company may seek bankruptcy relief. A more complete discussion of the treatment of RBL facilities in a bankruptcy case is beyond the scope of this article. The discussion that follows addresses the impact of bankruptcy on several of the types of agreements E&P companies use to raise capital, including, by way of example, oil and gas leases and joint operating agreements.

What Happens in Bankruptcy?

Oil and Gas Leases

The status of rights under oil and gas agreements, including oil and gas leases and joint operating agreements, can be affected by bankruptcy law. A few of the common issues that arise in oil and gas bankruptcy cases include the treatment of joint operating agreements, oil and gas leases, and farmout agreements. The treatment of oil and gas agreements under the Bankruptcy Code is dependent on the characterization of such agreements under state law. It is therefore crucial to be aware of how the mineral law of the applicable state characterizes your rights. For example, while joint operating agreements are almost always executory contracts, an oil and gas lease may, depending on the governing non-bankruptcy law, constitute either evidence of an interest in real property that is subject to assumption or rejection under Section 365 of the Bankruptcy Code or an unexpired lease that is subject to assumption or rejection under Section 365.

Despite employing the noun "lease" in its description, an oil and gas lease under the law of several states is not an unexpired lease subject to rejection in bankruptcy, but rather is treated as a real property interest. The question of whether an oil and gas lease falls within the definition of either executory contract or unexpired lease, as those terms are used in Section 365 of the Bankruptcy Code, is determined by referring to the applicable non-bankruptcy law, see Butner v. United States, 440 U.S. 48 (1979). The nature of the property right created by an oil and gas lease varies from state to state. In Texas and Pennsylvania, for example, oil and gas leaseholds are classified as real estate, while in Kansas, a lease is essentially a license to go upon the land in search of oil and is subject to assumption or rejection under Section 365 of the Bankruptcy Code, see Terry Oilfield Supply Co. v. Am. Sec. Bank, 195 B.R. 66, 70 (S.D. Tex. 1996); Jacobs v. CNG Transmission Corp., 332 F. Supp. 2d 759, 772 (W.D. Pa. 2004). But see In re Powell, 482 B.R. 873, 878 (Bankr. M.D. Pa. 2012) (holding that an oil and gas lease is "clearly" a lease of real property within the bankruptcy definition). See also Chesapeake Appalachia, LLC v. Powell (In re Powell), 2015 U.S. Dist. LEXIS 152509 (M.D. Pa. Nov. 10, 2015).

If a lease is classified as a real property interest rather than as a lease, a debtor who is a lessor cannot reject the lease and thus deprive the lessee of its expected benefits under the lease. Although a lease that is classified as an executory contract or unexpired lease is subject to rejection, some recent case law has suggested that under Section 365(h) of the Bankruptcy Code, which allows a lessee of an unexpired and already commenced lease of real property to retain its rights under the lease that are in or appurtenant to the real property for the balance of the term of the lease, "rejection would not appear to oust [lessees] from their rights to occupy the premises," see In re Powell, 482 B.R. at 879.

Although the parties cannot control whether a lease will be characterized as an executory contract or unexpired lease, a lessee can prepare for the risk of rejection in bankruptcy by crafting and defining its rights under the lease so that they will likely be found to be "in and appurtenant to the real property" under Section 365(h).

Joint Operating Agreements

Joint operating agreements are uniformly held to be executory contracts and can thus be assumed or rejected under Section 365 of the Bankruptcy Code, see In re Wilson, 69 B.R. 960, 963 (Bankr. N.D. Tex. 1987). Like any rights created under an executory contract, a party's rights under a joint operating agreement are at risk in the event of a bankruptcy filing. Although the risk of rejection cannot be entirely eviscerated, a party may mitigate that risk by (1) including a standard provision ensuring that the joint operating agreement is construed as an executory contract and providing for adequate assurance of performance; (2) filing a memorandum of the operating agreement of record to protect any contractual lien rights; (3) negotiating for and preserving offset and recoupment rights; and (4) drafting the operating agreement to protect certain rights as covenants running with the land, which are not subject to rejection in bankruptcy.

Why Buy or Sell E&P Assets Using the Bankruptcy Courts?

Any purchaser of distressed oil and gas assets must address certain risks endemic to distressed M&A transactions. First and foremost, such a purchaser must evaluate the fraudulent transfer risk created by the purchase of any assets at a "bargain" price. Fraudulent transfer risk refers to the ability of a court to look as far back as six years to find that a purchase price paid was less than reasonably equivalent value for the assets that were acquired, at a time when the seller was insolvent or in "financial distress" of the type listed in the applicable statutes. (For the elements of a fraudulent transfer under the Bankruptcy Code, see 11 U.S.C. § 548, as amended. Virtually every jurisdiction has a debtor and creditor law covering the voidability of fraudulent transfers. See also 11 U.S.C. § 544, as amended, which imports such state law into the Bankruptcy Code.)

There are two significant elements that compose the fraudulent transfer risk. First, if there is a finding that there has been a fraudulent transfer, the purchaser of an asset may be forced to pay additional sums for an asset it thought it had purchased at an agreed-upon (lower) price. Second, there is the cost of defending an action alleging the existence of a fraudulent transfer. Such defense costs can be substantial, especially in more complex cases. Sales of distressed businesses or their assets tend to be made under duress, at a time when a company may be insolvent, and involve assets for which potential buyers are wary of overpaying. Thus, such sales carry a heightened risk of being made for less than reasonably equivalent value and of the seller being found to have been insolvent at the time of sale.

Another risk associated with distressed M&A transactions is the risk that the seller will end up in a bankruptcy case after the signing of an agreement to sell to a purchaser but prior to a closing of the sale transaction. This scenario subjects the purchaser to the risk that the now-bankrupt seller will exercise its rights under Section 365 of the Bankruptcy Code to reject the sale agreement or attempt to renegotiate the terms of the sale by threatening rejection. Section 365 of the Bankruptcy Code provides that a trustee or debtor in possession can assume or reject (with exceptions) its executory contracts and unexpired leases. A sale agreement, after signing and prior to closing, would be subject to the provisions of Section 365. Upon rejection, a seller will have no further obligations to perform under the agreement, and the purchaser will generally have an unsecured prepetition claim for the damages it incurs.

A third risk a purchaser has with respect to a distressed M&A transaction is that payments received by the purchaser post-closing but prefiling of a bankruptcy, including true-up payments or purchase price adjustments, may be avoidable by the seller as preferential transfers under Section 547 of the Bankruptcy Code, depending on timing.

In view of the considerable bankruptcy risk that exists with respect to distressed M&A transactions, purchasers have been reluctant to proceed in the ordinary course (i.e., entering into a sale agreement and closing on that agreement). Instead, purchasers have been requiring sellers of distressed assets, including oil and gas assets, to file for bankruptcy relief and obtain bankruptcy court approval of the proposed sale despite auction-related risk and the expense associated with a bankruptcy sale process. By doing so, not only does the purchaser mitigate much of the bankruptcy risk described above, but a sale pursuant to the applicable provisions of the Bankruptcy Code may afford the purchaser certain additional benefits available under the Bankruptcy Code.

There are two ways an entity can sell its business or substantially all of its assets in a bankruptcy case filed under Chapter 11 of the Bankruptcy Code. First, an entity can sell pursuant to a plan of reorganization. A plan of reorganization is essentially an agreement between a debtor entity and its stakeholders settling the claims of the stakeholders, using the value of the debtor or its assets to fund such settlement. The filing of a reorganization plan comes at the end of a case. More often than not, a Chapter 11 case can be complex, and it is not unusual for a case to last more than a year. Also, as is currently occurring with oil and gas, there is a continued risk during the pendency of a Chapter 11 case that asset values will continue to erode—the so-called melting ice cube.

The alternative to a Chapter 11 plan process is a Section 363 sale. Traditionally, debtors used Section 363 to sell discrete assets, specific business units, or subsidiaries. Unlike a plan of reorganization or a sale that occurs under a plan approved at the end of a case, a Section 363 sale can occur at any time during the Chapter 11 process.

In recent years, many of the Chapter 11 cases filed by E&P companies are being filed together with a motion to sell substantially all of such entities' assets, pursuant to Section 363 of the Bankruptcy Code. These "Section 363 cases" tend to move quickly, which benefits both buyers of distressed assets and stakeholders that may have an interest in such assets. The speed of such cases benefits stakeholders by reducing the costs associated with operating a distressed business entity and benefits buyers by allowing them to gain control of the assets they are buying, with the blessing of a bankruptcy court, without the delay that a longer bankruptcy process might engender. In the current low-price environment and due to the benefits to buyers and stakeholders alike, there is no reason to think there will be a slowdown any time soon in the filing of oil and gas Section 363 cases.

The views expressed herein are solely those of the author as of the date this article was written and such views should not be attributed to Blank Rome LLP or to any of its clients.

Ira L. Herman, Partner, Blank Rome LLP

Ira Herman concentrates his practice on restructuring and bankruptcy matters with emphasis on distressed public debt issues, secured and unsecured loans, cross-border insolvency matters, distressed M&A, and corporate governance.

Ira regularly advises his clients, including equity investors and lenders, on the management of bankruptcy risk in their transactions, asset dispositions, inter-creditor issues, and distressed M&A. He also regularly counsels indenture trustees regarding defaulted public debt issue. Additionally, he provides restructuring and bankruptcy advice to financially distressed businesses and their management, including with regard to corporate governance issues.

As a court-appointed mediator, Ira has been able to facilitate the resolution of controversies involving U.S. and non-U.S. parties concerning bankruptcy and commercial law issues. He is a skilled listener who is able to solve problems and address the needs of the parties to a dispute by employing his knowledge of the law and creativity.

With all his clients, Ira seeks to be a partner and trusted adviser who works hard to understand a client's business to achieve the best possible outcomes. He strives to be efficient, cost effective, and proactive in discussing the impact of legal trends on their businesses, managing risk, and making the client's job as stress-free as possible.

Ira annually updates "Anticipating and Managing Bankruptcy Risk," a series of articles he has written for the Financial Restructuring & Bankruptcy module of *LexisNexis Practical Guidance®*. He has served for five years on its editorial advisory board and has also served on Law360's Bankruptcy Editorial Advisory Board. In 2022, Ira updated the chapter titled "Bankruptcy" in the treatise *Negotiating and Drafting Commercial Leases* (2022, Full Court Press).

During law school, Ira served as the Articles Editor for the *Boston University International Law Journal* and while earning his bachelor's degree, he served as editor-in-chief of The Polis, the college political science journal.