

2026

Spindletop Energy Primer

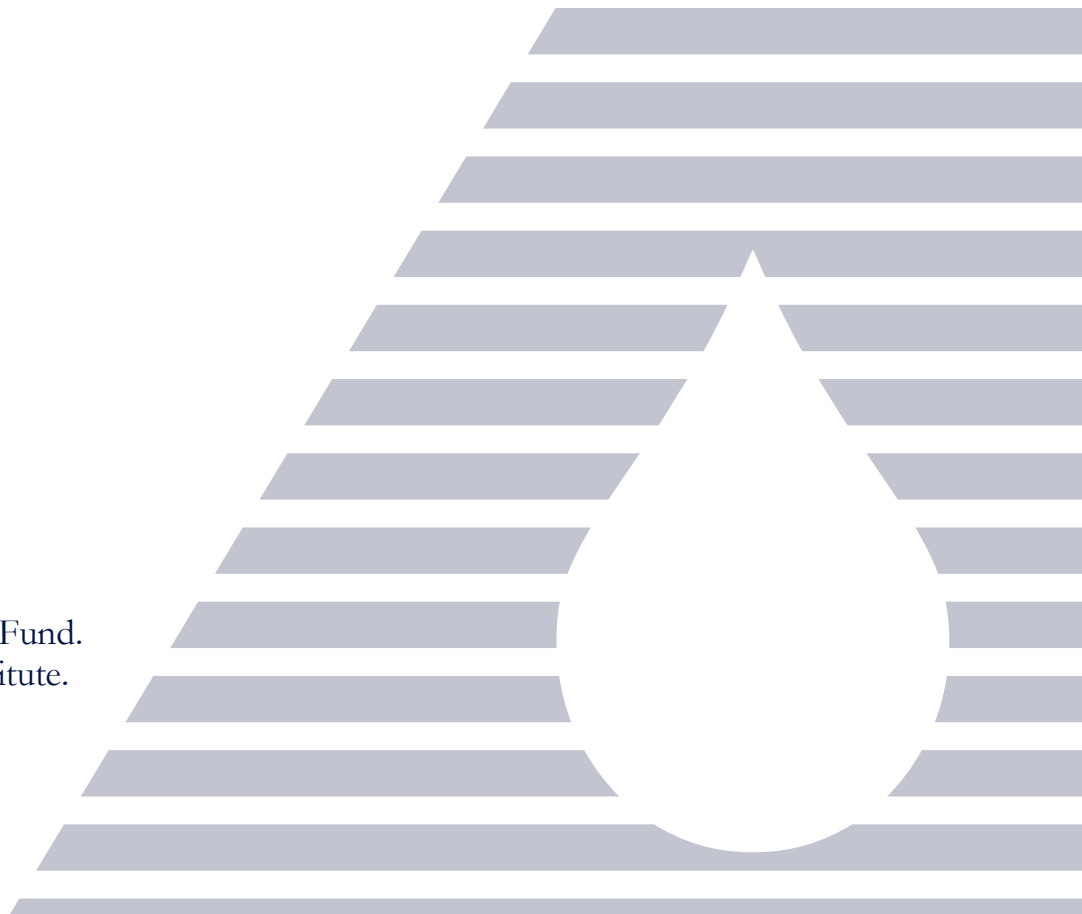
Break into Energy & Investment Banking

August 2026

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Oil and Gas: The Backbone of Modern Energy

The Importance of Energy Security

Energy is the foundation of modern human civilization, yet access to reliable, affordable energy remains one of the most profound inequalities in the world today. Currently, one-third of humanity still lacks access to basic modern energy, and over two billion people continue to cook their daily meals using traditional biomass fuels, including wood, dung and agricultural waste, generating indoor air pollution that the World Health Organization estimates kills over three million people annually, a figure comparable to the combined death toll of malaria, tuberculosis, and HIV/AIDS. The World Health Organization's research further highlights that in sub-Saharan Africa, five out of every six people lack access to clean cooking resources, and household air pollution from inefficient cooking fuels was linked to nearly 500,000 premature deaths in the region in 2018 alone. The contrast between energy-rich and energy-poor societies is perhaps nowhere more starkly illustrated than on the Korean Peninsula, where South Korea has 17 times the per capita energy consumption of North Korea, a life expectancy 11 years longer, and a child mortality rate 10 times lower than in North Korea.

Beyond human health, energy security has resurfaced as one of the defining geopolitical challenges of the modern era. Europe's dependence on Russian natural gas, weaponized following the invasion of Ukraine, demonstrated in real time how energy vulnerability translates directly into political vulnerability and economic disruption. The most recent U.S.–Iran conflict and the closure of the Strait of Hormuz have only reinforced the same realization on a global scale, sending oil prices soaring and forcing every major importing nation to confront the impact on their supply chains. The fundamental conclusion is straightforward: energy is not only a global economic input commodity but is also tightly linked to human development, health, and national security, and the nations and companies that can provide it reliably and affordably will sit at the center of global power for decades to come.

The Energy Sector

The energy sector is a broad term describing a complex, interrelated network of companies directly and indirectly involved in producing and distributing the “energy” needed to power the economy. Often used interchangeably with oil & gas, in 2026 it refers to more than that subsector. Its companies span Exploration & Production, Natural Resource Transportation & Storage, Refining & Petrochemicals, Renewable Energy (Wind, Solar, Nuclear, Battery Storage), and Power & Utilities.

Oil and Gas Macro

Oil and gas macro refers to the overall trends and analysis of global supply and demand in the oil and natural gas markets. Several key performance indicators (KPIs) are often the core focus when looking at the macro, such as rig count, storage, and drilling permit activities. The primary objective

is to understand commodity price cycles and industry activity levels, both historically and on a forward basis, by analyzing global supply/demand dynamics.

Oil and Gas Commodities

Oil and gas is the largest industry that makes up the energy sector, as more than 80% of the current world's consumption of primary energy is derived from oil and natural gas refined products. The primary commodities within the oil and gas industry are **oil, natural gas, and natural gas liquids (NGLs)**. Since these organic compounds are comprised of hydrogen and carbon, they are collectively referred to as **hydrocarbons**, or **fossil fuels**. When oil is pulled out of the ground, it is called **crude oil** (meaning not processed or unrefined). When you hear "oil prices" discussed in the news, they are referring to crude oil pricing. Different reservoirs produce different types of crude. The two most popular benchmarks for crude prices are **West Texas Intermediate (WTI)**, which can be extracted in the United States, and **Brent** from Europe (North Sea). Crude oil is not usable right away and is typically **refined** into various usable forms such as gasoline, heating oil, jet fuel, and even the asphalt used to construct roads. Natural gas is 70-90% **methane (CH₄)** and can be referred to as "**dry-gas**" or "**wet-gas**." The gas is "wetter" as its composition of ethane, propane, and butane is greater. In the United States, natural gas is used heavily in electrical power generation, heating, and cooking, as it is a highly dispatchable fuel (can be turned on and off quickly) and has historically seen low prices, fewer carbon emissions than coal, and an abundance domestically.

Oil and natural gas are quoted using unit conventions that pair a base measure with a prefix denoting scale. These prefixes derive from Roman numerals: M means thousand, MM means million, B means billion, and T means trillion. The most common early-career point of confusion is that M means thousand here, not million. Oil volumes are measured in barrels. **Bbl** is one barrel (roughly 42 U.S. gallons), **Mbbl** is one thousand barrels, and **MMbbl** is one million barrels. Natural gas volumes are measured in cubic feet, running from **Mcf** (one thousand cubic feet) to **MMcf** (one million), **Bcf** (one billion), and **Tcf** (one trillion).

Two further conventions capture energy content and equivalence. **MMBtu**, or one million British thermal units, measures energy (heat) content rather than volume, and natural gas is often priced on this basis; one Mcf of gas is approximately one MMBtu, though the exact ratio depends on the gas's heat content. **BOE**, or barrels of oil equivalent, converts gas volumes onto an oil-equivalent basis so that mixed oil and gas production can be expressed as a single figure, using a standard conversion of **6 Mcf of gas to 1 barrel of oil** based on energy content.

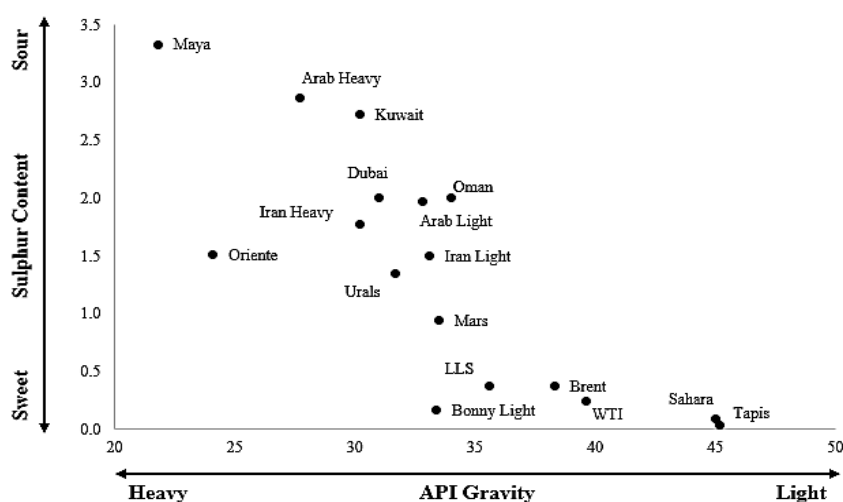
Finally, these measures are often expressed as daily production rates by appending "/d," as in MMcf/d (million cubic feet per day) or BOE/d (barrels of oil equivalent per day), whereas reserves are typically stated as an absolute quantity rather than a rate.

Qualities of Crude Oil

Crude oil is defined by two of its qualities: density and sulfur content. Density is determined by a measure called **API gravity**. Note that API gravity is a *reverse* measure of density, so a crude with a higher API is less dense. A crude with an API gravity of 31.1° or more is considered **light**, while a crude with an API gravity of less than 10 is considered **heavy**.

The other quality that crude is measured by is sulfur content. Crudes with a sulfur content of less than 0.7% are called **sweet**, while those with a sulfur content greater than 0.7% are called **sour**.

By analyzing both of these qualities, one can identify where the oil originates from. Below is a chart that maps some major crudes and their places on the light/heavy and sweet/sour continuum.



Different areas contain crude with different qualities. For instance, WTI is a light, sweet crude benchmark supplied by production from several U.S. regions and priced at Cushing, Oklahoma. On the other hand, many of the crudes that come from Middle Eastern countries like Saudi Arabia and the United Arab Emirates are heavy, sour crudes. Refineries are set up to process certain types of crude, and it takes long periods of maintenance to switch them over to other types. For this reason, it is important for oil traders employed by refiners to ensure they have access to crudes with qualities that they can process.

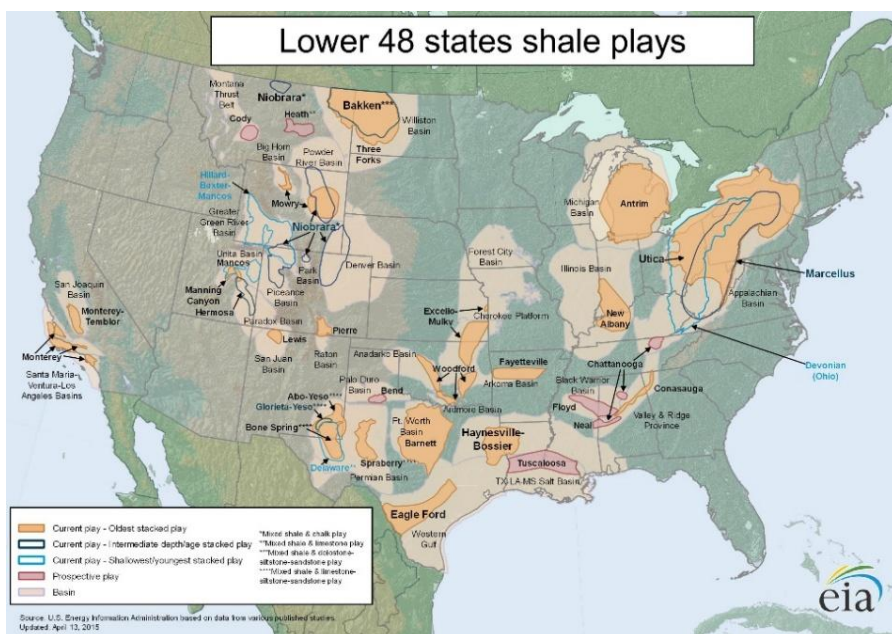
Qualities of Natural Gas

Natural gas is a combustible, colorless, and odorless gas that consists **primarily of methane** as well as small amounts of natural gas liquids (NGLs) and non-hydrocarbon gases. As stated above, natural gas produced from a well is referred to as “wet” as it typically contains **NGLs such as ethane, propane, and butane**. During gas **processing**, NGLs such as ethane, propane, and butane are separated out from the raw natural gas stream, leaving dry (pipeline-quality) natural gas. From there, fractionation splits the mixed stream into its individual components, each of which can be marketed as a distinct product (broken down below).

- **Ethane (C_2H_6):** Applications include plastics production and petrochemical feedstock. Examples of end products include plastics, plastic bags, antifreeze, and detergent.
- **Propane (C_3H_8):** Applications include residential and commercial heating, cooking fuel, small stoves, and petrochemical feedstock.
- **Butane (C_4H_{10}):** Can be blended in with gasoline and propane. Examples of end products include synthetic rubber for tires and lighter fuel. In its purest form, butane is useful as a refrigerant. Additionally, when combined with propane, butane becomes liquefied petroleum gas (LPG).
- **Isobutane (C_4H_{10}):** Similar to butane but with a different molecular structure. Isobutane is a key feedstock in refineries for producing high-octane gasoline. It is also used as a feedstock in petrochemicals, as an aerosol propellant, and is blended with LPG for cooking fuel.

Natural Gas can be **produced either from gas-rich formations** such as the Marcellus Shale, Barnett Shale, and Haynesville Shale plays or as a by-product of oil-directed drilling, in which case it is referred to as “associated gas.”

Natural gas is typically transported through pipelines or compressed in cylinders for transportation. It is important to note that Natural Gas contains contaminants and water molecules that need to be removed prior to transportation.



There are situations **where it is not feasible or cost-effective** to transport natural gas through pipelines or cylinders, such as when the gas must be transported over long distances or across oceans. In these situations, natural gas is liquefied by cooling it to a temperature of around -162°C (-260°F), which reduces its volume by more than **600 times compared to its gaseous state**. The resulting **Liquefied Natural Gas (LNG)** takes up less space and is easier and less expensive to transport over long distances. The most popular way of transporting LNG over long distances is usually to load it onto ships and specially designed LNG carriers to get to regasification infrastructure, where gas can be processed back from its liquid state to a gaseous state for consumption. Sometimes, both liquefaction and regasification processing units can be placed on floating vessels. In this scenario, the modules are called **Floating LNG (FLNG) or Floating Storage Regasification Units (FSRUs)**. Abundant domestic natural gas has turned the U.S. into a major LNG exporter, alongside other dominant exporters such as Qatar and Australia. Regions like Asia and Europe rely heavily on LNG imports from these countries because they lack sufficient domestic hydrocarbons, which leaves them

more exposed to commodity price swings than net energy exporters. LNG has played a **significant role in making natural gas more accessible and affordable on a global scale**, allowing for increased use in power generation, heating, and transportation.

Major U.S. Onshore Basins

There are many oil- and gas-producing regions around the United States. These areas have allowed the U.S. to skyrocket to the top producer of crude oil in the world. Fossil fuel production in Texas happens in the Barnett and Eagle Ford Shales, as well as the **Permian Basin**. The Permian has been a prolific area of production and accounts for 41.3% of all crude oil produced in the U.S.

There are other production regions around the U.S., including the DJ Basin and Niobrara Shale in Colorado, the Bakken Shale in North Dakota, the Scoop-Stack in Oklahoma, the Haynesville in East Texas and Louisiana, the Utica and Marcellus Shale in the Northeast, and Prudhoe Bay in Alaska.

Each of these basins produces different quantities of oil, gas, and NGLs, and the economics involved in producing in each is different and very localized, as each state's regulations impact the development of these basins. For instance, the DJ Basin has many regulations that make it far more expensive to produce when compared to regions in more energy-friendly states.



History of Oil & Gas

Key Periods of O&G History

- Discovery of Oil & Gas
- Commodity Price Volatility in the 1970s
- The Shale Revolution
- Price Crash of 2014–2016
- COVID-19 Pandemic
- U.S.–Iran Conflict
- Current Landscape & Outlook

Discovery of Oil and Gas

The modern discovery of oil can be traced back to the mid-19th century in 1859, when **Edwin Drake** drilled the first commercial oil well in Titusville, Pennsylvania. For more than a century afterward, production was almost entirely conventional, meaning operators drilled vertical wells into porous, permeable rock where oil had collected in natural traps and flowed to the surface under its own pressure or with simple pumping. The challenge was finding these reservoirs. The industry advanced through better understanding different locations, while developing better methods and techniques, moving from drilling near surface oil seeps to using seismic surveys and well logging equipment to map the subsurface of the ground.

These discoveries and industrial developments gave rise to the giants of the industry such as **John D. Rockefeller**, who founded Standard Oil in 1870 in Cleveland, Ohio, and became dominant by consolidating the refining business, then extending control over pipelines and distribution to squeeze out competitors. The industry dramatically changed in 1901, when the **Spindletop** well near Beaumont, Texas, blew out in a gusher flowing at roughly 100,000 barrels a day, more than every other U.S. well at the time. That discovery kicked off an oil rush in Texas and the Gulf Coast and created an opening for new companies outside Standard Oil's control. New companies, such as Gulf and Texaco, became dominant by building integrated operations that ran from the wellhead to refining the oil into usable products distributed to gas stations, scaling rapidly on the crude produced by Spindletop and the other sites that quickly followed.

Commodity Price Volatility in the 1970s

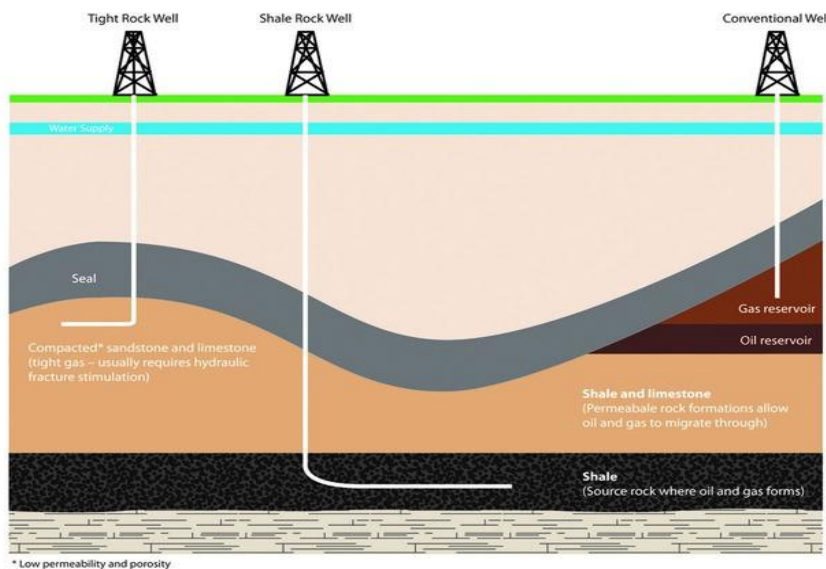
Before the 1970s, oil price fluctuations were relatively subdued due to the prevailing oligopolistic structure of the global oil market, with only a handful of dominant players, colloquially referred to as the “Seven Sisters,” such as BP, Chevron, ExxonMobil, and Shell. These powerful entities exerted

considerable influence over the entire spectrum of oil production, refining, and distribution, thereby maintaining a relatively stable pricing regime. The Seven Sisters leveraged their control over the market to strategically adjust prices in their favor and succeeded in securing profitable agreements with oil-producing nations to sustain this stability.

The oil embargo of 1973, triggered by the Yom Kippur War, also known as the October War or Arab-Israeli War, sharply reduced global oil supply and caused a sudden price surge, exposing the fragility of the market to supply disruptions. In response, the Nixon administration negotiated a landmark agreement with Saudi Arabia in 1974: the U.S. would provide military protection and arms sales in exchange for Saudi Arabia pricing its oil exclusively in U.S. dollars and recycling petrodollar surpluses into U.S. Treasuries. This arrangement became the foundation of the **petrodollar system**, cementing dollar dominance in global energy markets and giving the U.S. significant leverage over both oil pricing and global capital flows.

Furthermore, the entry of new oil-producing countries such as Nigeria and Angola into the market marked a turning point in the balance of power in the global oil market. These new producers were able to leverage their bargaining power to negotiate better prices for their oil, challenging the dominance of the Seven Sisters and shifting the market from a seller's to a buyer's market, further contributing to oil price volatility.

The Shale Revolution



In the early 2000s, the **Shale Revolution** began in the United States. This allowed the U.S. to become one of the largest producers of crude oil and natural gas. Historically, technology only allowed **conventional wells** to be drilled. Conventional wells are drilled straight down and extract oil, gas, and NGLs to the surface.

However, two different technologies were developed that allowed **unconventional wells** to begin being drilled. The first of these was

horizontal drilling, where rig operators slightly adjust the angle at which they drill to gradually move from drilling vertically to drilling horizontally. This takes space and time, and the drill bit can only move around 10° every 100 feet that is drilled. It takes around 900 feet of drilling to make the 90° turn necessary to move from vertical to horizontal. For context, this is equivalent to the height of

the Statue of Liberty stacked on top of itself three times. Horizontal drilling allows producers to cover a larger area of shale deposits, which contain hydrocarbon molecules trapped within them.

The other important technology was **hydraulic fracturing, or fracking**. Fracking is a method of extracting oil and natural gas by injecting a high-pressure mixture of water, sand, and chemicals into underground rock formations to create fractures that help the flow of hydrocarbons back to the surface. This is necessary for drilling in shale because shale has high **porosity**, meaning it can store large amounts of oil and gas, but low **permeability**, meaning the formation is too tight to allow the easy flow of oil and gas through the rock. Once the high-pressure mixture has fractured the rock, the sand, otherwise known as **proppant**, keeps the formation from closing in on itself while allowing the hydrocarbons to pass through and up to the surface.

Through horizontal drilling and fracking, oil and gas companies were able to extract vast amounts of previously inaccessible oil and natural gas reserves from shale formations, primarily in the Permian Basin in Texas and New Mexico, the Bakken Formation in North Dakota, and the Marcellus Formation in the northeastern United States. The Shale Revolution has transformed the U.S. energy landscape, making the country one of the world's top oil and natural gas producers and significantly reducing its reliance on foreign energy sources.

Oil and Gas Price Crash (2014–2016)

From 2009–2013, crude oil fluctuated between roughly \$70–\$120/bbl. However, oil and gas prices crashed in 2014–2016 primarily due to a combination of oversupply and weak demand. During the early 2010s, the Shale Revolution in the United States led to a surge in oil and gas production, increasing the global supply of these commodities. At the same time, demand for oil and gas weakened due to slowing economic growth in China and Europe. Although oil and gas are inelastic in nature, as the oversupply of oil and gas grew, prices began to decline sharply. Further failures by OPEC to reach production cut agreements compounded the downward pricing pressures on oil and natural gas prices, with the benchmark price of Brent crude falling from over \$100 per barrel in mid-2014 to below \$30 per barrel in early 2016. Natural gas prices also fell sharply during this period, with the benchmark price of Henry Hub natural gas dropping from over \$4 per MMBtu in 2014 to below \$2 per MMBtu in early 2016.

The crash had sweeping consequences for the energy industry. Oil and gas companies were forced to cut production, lay off workers, and dramatically reduce capital expenditures. A key theme that emerged from the crisis was **capital discipline**, resulting from energy companies having over-leveraged themselves during the boom years, where they borrowed heavily by issuing debt, drawing on credit facilities, and betting that \$80–100+ oil prices would persist. The crash forced companies that survived to prioritize balance sheet health and returning cash to shareholders over aggressive growth.

COVID-19 Pandemic

The COVID-19 pandemic had a significant impact on the oil and gas industry in several ways:

1. **Decline in demand:** The pandemic led to a global economic slowdown and reduced travel and transportation, which significantly reduced the demand for oil and gas. As a result, oil prices plummeted to historic lows, with the benchmark price of Brent crude falling to below \$20 per barrel in April 2020.
2. **Oversupply:** At the same time, oil producers continued to pump oil even as demand declined, leading to a significant oversupply of oil in the market. This further contributed to the decline in oil prices, with many oil producers being forced to shut down wells and cut production.
3. **Reduced investment:** The economic uncertainty caused by the pandemic also led to reduced investment in the oil and gas industry, as companies were forced to cut costs and conserve cash. This had significant implications for the future of the industry, as many planned investments and projects were put on hold or canceled.
4. **Impact on workers:** The pandemic also had a significant impact on the workers in the oil and gas industry, with many being laid off or furloughed as companies cut costs. This had broader economic implications, particularly for countries and regions that are heavily dependent on the oil and gas industry.

Overall, the COVID-19 pandemic had a significant and far-reaching impact on the oil and gas industry, highlighting the vulnerabilities and challenges faced by this sector in an increasingly uncertain and rapidly changing global landscape.

Why Did Prices Go Negative During COVID?

Oil prices went negative during the COVID-19 pandemic **due to a combination of oversupply and storage constraints**. The pandemic led to a sharp decline in demand for oil, as people stayed home, and travel and transportation were reduced significantly. This decline in demand was exacerbated by the ongoing **oversupply of oil in the market, as oil producers continued to pump oil even as demand fell**.

As a result of the oversupply and reduced demand, there was a **significant build-up of oil inventories around the world**. However, storage capacity for oil is limited, and by April 2020, many storage facilities were nearing their capacity limits. This created a situation where oil producers were faced with the prospect of having to pay to store their oil, rather than selling it at a profit.

The negative oil prices were also driven by the mechanics of oil futures contracts. Oil futures contracts are financial instruments that allow investors to buy or sell oil at a specific price at a future

date. However, these contracts require physical delivery of oil, which means that at the end of the contract period, the buyer must take delivery of the oil. In April 2020, as the storage facilities neared capacity, buyers of oil futures contracts were unable to find space to store the oil they had contracted to buy. **This created a situation where sellers of oil futures contracts were willing to pay buyers to take the oil off their hands, leading to negative oil prices.**

Overall, the negative oil prices seen during the COVID-19 pandemic were a result of a combination of oversupply and storage constraints, as well as the mechanics of oil futures contracts. These factors created a unique and unprecedented situation in the oil market, with significant implications for the industry and the broader economy.

Russia–Ukraine War

Russia's invasion of Ukraine in February 2022 reshaped global energy markets and permanently altered how nations think about their energy supply. Prior to the war, Europe relied heavily on Russian natural gas, much of it delivered through the **Nord Stream Pipeline** system. When those flows were cut following the pipeline's destruction, and as Western nations imposed sweeping sanctions on Russian hydrocarbons, Europe was forced to rapidly restructure its energy supply. The continent turned primarily to Qatar and the United States to replace lost Russian volumes, importing large quantities of liquefied natural gas (LNG) to keep homes heated and industry running. This abrupt shift carried several lasting consequences for the energy landscape.

1. **Adjustments to the world supply chain and the rise of the LNG era:** Russian oil and gas were redirected toward buyers in Asia such as China and India, while Europe constructed LNG import facilities to receive seaborne LNG from the United States, Qatar, and other producers. With pipeline gas from Russia no longer viable, LNG became the critical bridge for European supply, accelerating demand for regasification terminals, LNG carriers, and new liquefaction capacity. The United States solidified its position as a leading LNG exporter, and Qatar reinforced its role as a cornerstone supplier, marking a structural shift toward a more globalized, seaborne gas market.
2. **A shift from decarbonization toward energy security:** Many countries that had been focused primarily on decarbonization recalibrated their priorities toward securing reliable supply. While long-term climate goals remained in place, the immediate emphasis moved to ensuring affordable and dependable energy. The crisis reminded governments and markets that oil and natural gas remain foundational to modern economies. When supply was threatened, prices spiked and the vulnerability of nations dependent on a single supplier became impossible to ignore. The war also demonstrated how quickly energy can be weaponized, as overreliance on one supplier proved to be a serious liability. Countries began treating secure, diversified supply as a matter of national security.

U.S.–Iran Conflict

The U.S.–Iran conflict that began on February 28, 2026, provides a vivid, real-time case study into the geopolitical value of energy commodities in a modern, globalized economy. Historically, tensions between the United States and Iran stretch back to the Islamic Revolution in 1979, with the immediate catalyst for the 2026 conflict being the threat of Iran’s nuclear program and the subsequent U.S. attacks on its nuclear facilities. Iran’s most strategic and impactful response was the closure of the **Strait of Hormuz**, a narrow waterway connecting the Persian Gulf to the Arabian Sea where roughly one-fifth of global oil shipments, approximately 20 million barrels per day, pass through. The strait serves as the primary export corridor for many of the Middle East exporters such as Saudi Arabia, Iraq, the UAE, Kuwait, and Iran itself.



The oil market reacted immediately. Brent crude was trading around \$72 a barrel on February 27, just before the conflict began. March marked one of the largest monthly oil price surges on record, with Brent gaining 67% as Gulf output fell and exports stalled, ultimately peaking near \$120 a barrel. Iraq, Saudi Arabia, and the UAE shut in production in response to the disrupted navigation, and attacks on energy infrastructure further supported rising prices, with Brent surpassing \$100 per barrel on March 12.

While WTI and Brent prices both rose above \$100 for a short period, the most dramatic response to the Strait of Hormuz closing was seen in the **DME Oman Crude Index**, where prices almost hit \$170 a barrel on March 20. The divergence reflects the fact that Brent and WTI never transit the Strait, while DME Oman is a physically delivered contract serving as the pricing basis for the Gulf exports that were physically stranded from the strait closure.

While the future of the United States–Iran conflict remains uncertain, several points have emerged clearly. First, the United States has gained substantial leverage in the LNG market. On March 18–19, 2026, Iranian missile strikes hit two of the fourteen LNG trains at Qatar’s Ras Laffan complex, the world’s largest LNG export facility, removing roughly 12.8 million tonnes per year, about 17% of Qatar’s LNG export capacity, which QatarEnergy has said will take three to five years to repair at an estimated \$20 billion in lost annual revenue. QatarEnergy declared force majeure on long-term contracts with buyers in Italy, Belgium, South Korea, and China. European utilities, which had leaned heavily on Qatari LNG since reducing their dependence on Russian pipeline gas after the Ukraine war, were pushed toward the spot market and toward alternative suppliers including the United States, whose cargoes avoid the Strait entirely.

Second, China has been able to weather the storm better than countries with more inelastic demand for crude from Iran, such as Pakistan, for three reasons. Through 2025 it aggressively built its strategic and commercial crude inventories, adding an estimated 900,000 barrels per day while Brent held in a relatively tight range around \$68. Its multi-year buildout of electric-vehicle production has structurally reduced marginal oil demand. In early March, Beijing's National Development and Reform Commission instructed the country's top refiners to suspend diesel and gasoline exports, stop signing new export contracts, and negotiate the cancellation of already-agreed cargoes, redirecting into the domestic market volumes that would otherwise have been sold abroad, insulating Chinese consumers at the expense of regional buyers such as Bangladesh and the Philippines that rely on Chinese fuel.

Third, the conflict rippled into two products that rely heavily on Qatari natural gas: helium and fertilizer. Helium is recovered as a byproduct of LNG liquefaction, and because LNG liquefaction had largely been taken offline at Ras Laffan, Qatar's supply, roughly one-third of the world's helium, per the United States Geological Survey, went offline at once, sending spot prices up sharply. This is important in the context of the AI boom, where helium is used to cool and protect the wafers, the thin slices of silicon that chips are built on, with no substitute. Fertilizer follows the same logic, since natural gas is the primary feedstock for nitrogen fertilizers and the Persian Gulf accounts for roughly one-third of global urea exports, a widely used fertilizer. With Iran and Qatar halting output and the Strait of Hormuz closure stranding the region's seaborne trade, urea prices climbed above \$850 per metric ton in April, roughly 80% higher than in February. Because urea is essential to crop production, a prolonged shortage raises farming costs worldwide and threatens the food supply of import-dependent nations.

Taken together, these disruptions trace how a single chokepoint transmits a regional conflict into oil, gas, food, and technology powering the AI boom, underscoring why the Strait of Hormuz remains one of the most consequential points in the global economy.

Energy Landscape

Domestic Policies of the Energy Sector

Reading the news, there is no doubt that energy is a very important issue in domestic politics in the United States. Candidates for public office are often asked many questions about their views on energy policy, and with the media talking more about climate change in recent years, energy has taken an even larger role in determining who is elected to office and how politicians and regulators govern the sector.

Certain regulations have been particularly hostile to the oil and gas industry and have made it harder for Upstream and Midstream companies to operate. Federal Agencies such as the **Environmental Protection Agency (EPA)** have strict rules in place regulating how fossil fuels are produced, transported, and stored. Fracking in particular has taken a lot of negative media coverage as activists claim that it can cause seismic tremors and pollute groundwater. Meanwhile, many opportunities exist for companies to capitalize on **tax credits** offered for new renewable energy projects.

At the state level, the oil and gas industry receives varied treatment depending on the policy environment. In states like Texas, North Dakota, Arkansas, and Louisiana, where oil and gas have long been a key driver of economic development, state governments tend to be favorable toward the industry. States that produce few hydrocarbons often take a different approach. California, for example, produces relatively little oil and gas and has adopted some of the strictest permitting and environmental rules in the country, which raises the cost and difficulty of new drilling. Similarly, New York sits on top of part of the Marcellus Shale but has restricted hydraulic fracturing and limited approvals for new pipeline projects, resulting in higher energy costs for consumers.

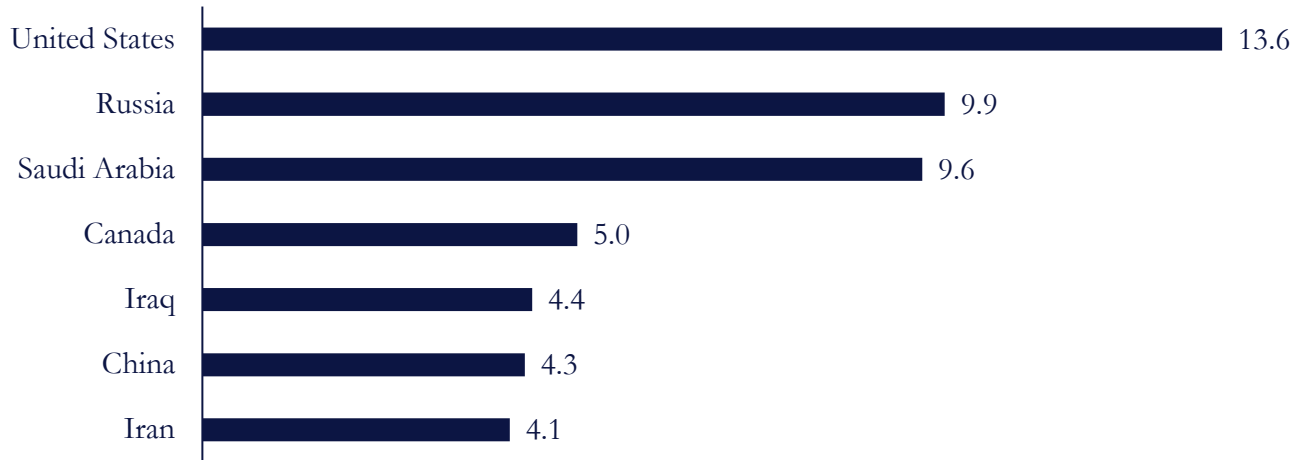
Many oil and gas production sites are on federal or state land, and so governments can easily end new leasing to E&P companies. This can halt new drilling in places such as Alaska. Additionally, projects such as the **Keystone XL Pipeline**, which would have allowed Canadian crude producers to export to the United States more easily, have been canceled.

Geopolitics of the Energy Sector

The political side of the energy sector extends outside of the United States into global politics as well. Events such as the Russia–Ukraine and U.S.–Iran conflicts have highlighted the importance of the sector in recent years.

Many countries around the world produce oil and gas, as can be seen in the crude oil production table showcasing the top producers of crude oil in 2025.

Top Global Crude Producers in 2025 (MMBbl/d)



Source: EIA, U.S. Global Investors, 2025.

Western countries like the United States and Canada treat the oil and gas industry like any other. Companies compete with one another and allow market forces to dictate their decisions regarding pricing and new drilling. However, in many countries, fossil fuel production is how the government balances its yearly fiscal budget. This ultimately causes the supply side of the oil and gas industry to be less elastic, as governments must continue drilling to shore up their budgets.

In Europe, the continent was historically dependent on Russian natural gas delivered through several pipelines. During Russia's invasion of Ukraine in 2022, a few strategic pipelines, most notably Nord Stream 1, were damaged, shutting down shipments toward Europe. Because of the conflict, the EU has been pressing toward a full ban on Russian pipeline gas by 2027, with France remaining the least exposed given that nuclear power supplies roughly 70% of its electricity. In order to replace the Russian gas, Europe pivoted toward U.S. LNG and Middle Eastern supply as replacements.

OPEC

The Organization of Petroleum Exporting Countries (OPEC) is an organization of various countries primarily in Africa and the Middle East that acted as a global monopoly on the supply of crude oil before the advent of the Shale Revolution. These countries were able to coordinate their crude production in order to ensure favorable pricing in the global market. In the 1970s, during the Yom Kippur War, where Israel fought a coalition of Arab countries led by Syria and Egypt, OPEC declared a global oil embargo that crippled Western countries, leaving Americans facing extremely high prices at the pump with little recourse. In the early 2010s, developments in unconventional drilling allowed the United States to become the top global producer of crude, fundamentally eroding OPEC's ability to control global prices as American output grew from 5.4 million barrels per day in 2010 to over 13 million today, joined by surging production from emerging countries like Canada and Guyana.

OPEC enforces its production quotas not just through negotiation but also through punishment. For instance, when member countries repeatedly overproduced their allotted volumes, Saudi Arabia and other core members have responded by flooding the market with additional supply to drive prices low enough that the cheating countries' excess barrels generate little to no profit. **Kazakhstan** has been a regular offender, consistently exceeding its OPEC+ quota throughout 2024 and into 2025 due to production commitments to international oil companies operating its major Tengiz and Kashagan fields. Saudi Arabia can deploy this tactic more aggressively than almost any other producer because its production costs are among the lowest in the world at roughly \$10 per barrel, substantially below Kazakhstan's breakeven, showing its economic advantage during times of sustained low oil prices. It must be noted that Saudi Arabia has a much higher fiscal breakeven price, the price at which the Kingdom balances its budget, at over \$90 per barrel in 2025.

The **UAE's** decision to leave OPEC on May 1, 2026, reflected years of frustration with a quota system that had become incompatible with Abu Dhabi's ambitions. The UAE had poured billions into expanding its production capacity to nearly 5 million barrels per day, yet OPEC rules permitted it to pump only around 3.2 million. When the U.S.–Iran conflict and the subsequent closure of the Strait of Hormuz forced countries to reroute exports, OPEC's quota system broke down, and the UAE seized the opening to leave the cartel with minimal impact and little disruption to fellow members. It was uniquely positioned to absorb the cost of departure: non-hydrocarbon activities such as tourism, logistics, and finance now contribute more than 70% of UAE GDP, easing the transition away from OPEC.

Major Energy Companies by Vertical

Majors: ExxonMobil (XOM), Chevron (CVX), Shell (SHEL), BP (BP)

Large Caps: ConocoPhillips (COP), EOG Resources (EOG), Diamondback Energy (FANG), Occidental Petroleum (OXY), Devon Energy (DVN), EQT Corporation (EQT), Expand Energy (EXE), Permian Resources (PR), Ovintiv (OVV), APA Corporation (APA), Antero Resources (AR)

Mid / Small Caps: Range Resources (RRC), SM Energy (SM), Chord Energy (CHRD), Matador Resources (MTDR), Magnolia Oil & Gas (MGY), Murphy Oil (MUR), CNX Resources (CNX), California Resources (CRC), Crescent Energy (CRGY), Comstock Resources (CRK), Gulfport Energy (GPOR), Northern Oil & Gas (NOG), Talos Energy (TALO), Mach Natural Resources (MNR), Kosmos Energy (KOS)

Minerals & Royalty: Texas Pacific Land (TPL), Viper Energy (VNOM), LandBridge (LB), Eagle Rock, Black Stone Minerals (BSM), PermRock Royalty Trust (PBT), Kimbell Royalty Partners (KRP), Dorchester Minerals (DMLP), WhiteHawk

In the United States, gas is priced by **Henry Hub** in **Erath, Louisiana**. Prices set at Henry Hub are quoted in dollars per MMBtu and serve as the benchmark for the entire North American market,

with regional prices trading at premiums or discounts depending on their distance from the hub. The U.S. is the most liberalized and transparent gas market in the world, meaning prices are set freely by supply and demand rather than by long-term contracts.

Europe and Asia price gas differently because neither developed a liquid spot market early on. Europe built its market on long-term contracts that tie the price of gas to a basket of competing fuels like gasoline and fuel oil. This structure gave suppliers enough certainty on future demand to justify expensive pipeline investments and gave buyers security of supply. A spot market has since developed around hubs like the **UK's National Balancing Point (NBP)** and the **Dutch Title Transfer Facility (TTF)**, but long-term contracts still make up most of the market. Asia followed a similar contract-based path, with LNG historically priced against crude oil, though the **Platts Japan Korea Marker (JKM)** has since emerged as the region's benchmark for spot LNG.

Natural Gas Liquids

NGLs sit between oil and gas in how they are priced, reflecting their dual nature as both gas-derived products and substitutes for crude-based feedstocks. Because NGLs are separated into distinct components – ethane, propane, butane, isobutane, and natural gasoline – each is priced individually based on its own supply and demand dynamics and end-market uses. Most U.S. NGLs are priced in **Mont Belvieu, Texas**, a major hub for fractionation, storage, and distribution, in much the same way that natural gas is priced against Henry Hub.

Each NGL component takes its price from the end market it serves. **Ethane** is used almost entirely as a petrochemical feedstock to make ethylene, so its price is driven by demand from petrochemical plants and the plastics market. **Propane** prices are seasonal, rising in winter on heating demand and also influenced by export markets and petrochemical feedstock demand. The heavier NGLs used in motor gasoline production track more closely with crude and refined product prices.

Liquefied Natural Gas

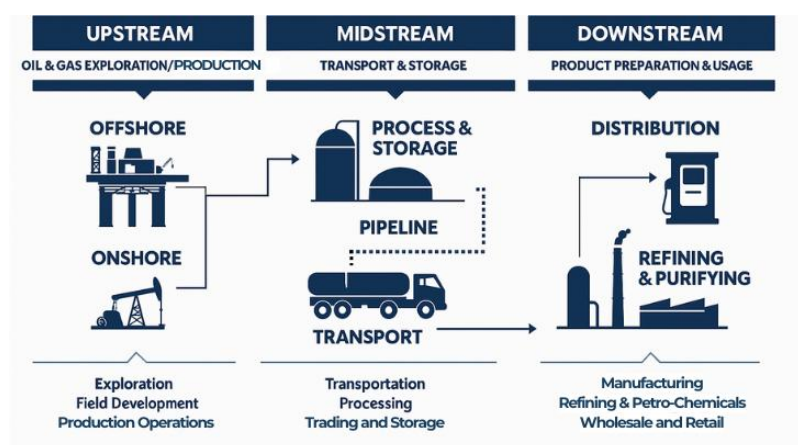
LNG is a contract business, with terms negotiated individually between buyer and seller, so no two contracts are priced exactly alike. This is made more complicated by the lack of a liquid global gas market outside the U.S. and UK, which leaves prices dislocated between regions and at times open to arbitrage. Traditionally, with Asian buyers dominating the market, LNG was priced off crude oil or a basket of energy alternatives. More recently, the rise of the U.S. as a dominant exporter of LNG has introduced Henry Hub-plus pricing, where buyers pay a percentage of the Henry Hub gas price plus a fee for liquefaction and transport, which adds transparency and a global price floor.

Three Sectors, Four Verticals

Overview

The four verticals are the broad categorizations of different companies within the oil and gas industry. Although some industry experts tend to recognize only three sectors, with oil field services (OFS) being a subsection of upstream, many energy finance professionals prefer four verticals, which is why it is laid out as such.

The four verticals are: **Upstream, Midstream, Downstream, and Oil Field Services (OFS).**



1. **Upstream:** Upstream companies, also known as **Exploration and Production (E&P)** companies, are companies that engage in the exploration of new fossil fuel resources and the production of these fossil fuels. Examples: Permian Resources, Diamondback, EQT, Expand Energy, and Occidental.
2. **Midstream:** Midstream companies are responsible for the storage and transportation of oil and gas between producers and buyers. This is commonly done via pipelines, trains, and trucks. Historically, many midstream companies have been structured as **Master Limited Partnerships (MLPs)** which allow for pass-through taxation. However, many have converted to C Corporations to attract more institutional investors, avoiding common MLP issues such as complex tax reporting and mutual fund ownership restrictions. Examples: Energy Transfer, Plains All American, Kinder Morgan, Williams, and ONEOK.
3. **Downstream:** Downstream companies are responsible for the refining as well as marketing of petroleum products to ordinary consumers. Downstream companies turn crude oil into products like gasoline, diesel, jet fuel, and other petroleum products. Examples: Valero, Phillips 66, Marathon Petroleum, Delek, and PBF.

4. **Oil Field Services (OFS):** OFS companies work closely with Upstream companies, providing various products and services in the exploration, development, and production of fossil fuels. Oil field services include seismology, drilling, fracking, and many other services. Examples: Halliburton, Schlumberger, Baker Hughes, and Liberty Energy.

There are also several **integrated** oil companies, such as ExxonMobil and Chevron, which operate across these verticals. While these companies are some of the largest in the energy sector, they do not provide investors with **pure-play** investment opportunities. A pure play is an investment that provides exposure to a single vertical, concept, or even basin. Outside of the United States, many oil companies are state-owned. These are called **National Oil Companies (NOCs)**, such as Saudi Arabia's Aramco. NOCs operate in very different ways from producers in the United States since they are owned by governments that have objectives outside of maximizing shareholder value.

Each vertical carries a different level of risk, and one of the most useful tools for measuring that risk is beta. Beta is fundamentally a **measure of systematic risk**, specifically how much risk a given investment carries relative to the broader market. A beta above 1 means a stock is more volatile than the market, amplifying both gains in an upswing and losses in a downturn. A beta below 1 implies relative stability, with the investment moving less dramatically than the market in either direction. In practice, investors use beta to understand how much commodity price risk, market sensitivity, and earnings volatility they are taking on when they buy into a particular company or sector. The **S&P 500**, a grouping of the 500 largest publicly traded U.S. companies by market capitalization, serves as the standard market proxy against which beta is measured.

Ranked from highest to lowest beta, the four verticals fall in the following order: 1. oilfield services, 2. upstream, 3. downstream, 4. midstream. OFS carries the most risk because when oil prices fall, operators cancel drilling contracts entirely, leaving OFS companies either not contracted or forced to discount their day rates. Upstream is next, as commodity prices directly affect revenue. Downstream is more insulated since refining margins can partially offset input cost swings. Midstream sits at the bottom of the risk spectrum, protected by **take-or-pay contracts** that lock in minimum volumes or force customers to pay penalties for falling short.

Minerals and Royalties

Overview

Within the Minerals and Royalties space, there are a couple of key parties to be aware of. First, the mineral rights owner, or the **lessor**, is the individual, company, or government that owns the rights to the minerals. Second, the **production syndicate** is an arrangement where multiple parties jointly own an oil and gas project. The operator manages the day-to-day operations, and non-operators own non-operating working interests in the project. Within this syndicate, the operator is referred to as the **lessee**, or the company that leases and drills for the hydrocarbons on the property. Production revenues and operating costs are shared based on each participant's ownership percentage. It is important to note that the United States is one of the few countries with private ownership of **mineral rights**, which are the rights to the valuable resources underneath their property. In most countries, the government owns these mineral rights, and a National Oil Company (NOC) typically handles the exploration and production. However, in the United States, companies often negotiate with individual landowners rather than governments to obtain the rights to the resources.

Mineral rights owners receive **royalties (generally 12.5% or 25% of production) as well as a sign-up bonus** from the lessee in exchange for access to their land and geology. Royalties are a key component in calculating the production syndicate's **net revenue interest, or NRI (1 – royalty%)**, which reflects the share of production revenue the syndicate actually keeps after fulfilling its obligation to pay the mineral rights owner. This NRI can further be broken down between members of the syndicate, with each member receiving a share of the total available NRI proportionate to its **working interest, or WI**. A working interest represents a share of ownership in the costs and net revenue from production. A mineral rights owner does not typically bear any costs from the well, so the costs are distributed among the syndicate based on each member's working interest. In contrast, the mineral rights owner receives a share of revenue equal to its royalty rate, so the syndicate receives revenues based on the working interest and NRI ($\text{Member Share of Costs} = \text{WI}$; $\text{Member Share of Revenue} = \text{NRI} \times \text{WI}$).

Tangibly, this relationship can be seen in the following example: Imagine there exists a mineral rights owner, an operator, and one non-operator. Based on the lease agreement between the mineral rights owner and the operator, the mineral rights owner will receive a 25% royalty, meaning the NRI is 75%. Assume, as the production syndicate, the operator has an 80% working interest, and the non-operator has a 20% working interest. If a well in the lease generates \$100 of total revenue, then the mineral rights owner will receive \$25, and the remaining \$75 will be left to the production syndicate to split based on working interest. As a result, the operator will receive 80% of the \$75, or \$60, and the non-operator will receive the remaining \$15. Now, say the well has capital and operating costs of \$50. Because the mineral rights owner does not bear costs, the costs will be allocated among the production syndicate based on working interest. Thus, the operator will pay for \$40 of costs, and the non-operator will pay \$10 of costs.

Contained within the oil and gas lease document between the landowner (lessor) and operator (lessee) are various important clauses.

Grant and lease terms: Define exactly what minerals are covered, the geographic boundaries of the lease, the primary term (typically 3–10 years), and the conditions under which the lease continues into a secondary term.

Habendum clause: Divides the lease into its two life stages: the primary term (a fixed window, typically 3–10 years, during which the operator can hold the lease without producing) and the secondary term (which continues the lease for as long as the well produces).

Bonus payment: An upfront cash payment made to the landowner at signing, separate from ongoing royalties, typically calculated on a per-acre basis.

Pooling: Allows an operator to combine multiple landowners' acreage into a single production unit and drill one well that holds all of the leases simultaneously. The tradeoff for the landowner is that instead of receiving royalties on the full well, they receive royalties only in proportion to how much of their acreage contributed to the total unit.

Pugh clause: Keeps an operator from holding land they aren't using. When acreage gets pooled, an operator could otherwise drill a single well on a small portion of a tract and use it to hold the entire tract under lease indefinitely. The Pugh clause prevents this by releasing the acreage not included in the producing unit, so the operator must either develop that remaining acreage with additional drilling or let it revert to the owner.

Shut-in royalty clause: Allows the operator to keep a lease by paying a set fee when a well is capable of production but is temporarily shut in, often because there is no pipeline connection, no available market, or prices are too low.

Force majeure clause: Suspends the operator's drilling and production obligations during events outside either party's control (hurricanes, tornadoes, etc.), and most importantly, prevents an operator from losing their leasehold interest.

Continued drilling obligation: Ensures the operator does not sit on the lease without producing, requiring ongoing development rather than holding acreage idle.

A **landman** is the link between an operator and the mineral owners whose rights it needs to drill, beginning with title research to establish who actually owns the minerals under a tract. The landman negotiates and secures a lease with each owner, setting the bonus, royalty, primary term, and holding clauses that govern the deal. Once production begins, that same title work feeds the division order that assigns each owner their share of revenue.

Onshore Upstream

Overview

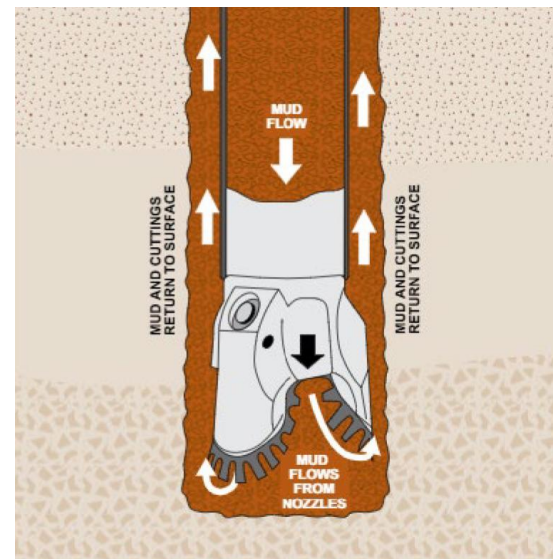
The upstream vertical in oil and gas is a complex process involving various activities that are conducted by Exploration and Production (E&P) companies. The primary goal of these companies is to find hydrocarbons. Once the location of the hydrocarbons has been identified via seismic evaluations, exploratory wells are drilled and temporarily produced to analyze and determine their economic viability. Depending on the results of the evaluation, the well may be profitable and kept online, or abandoned if it is a **dry hole**, meaning it cannot produce hydrocarbons at a rate that justifies the cost to drill.

To accomplish these tasks, E&P companies contract with drilling contractors and other service providers, known as oil field services companies, for the necessary equipment and technical expertise related to drilling and completion. The drilling process involves creating boreholes and inserting casings to secure the well, while completion involves installing necessary equipment to extract the hydrocarbons.

After the extraction process, the hydrocarbons are brought to the surface, where the initial separation and cleaning take place in order to separate the four phases (oil, natural gas, water, and sediment) to ensure they are marketable to midstream gathering and processing companies.

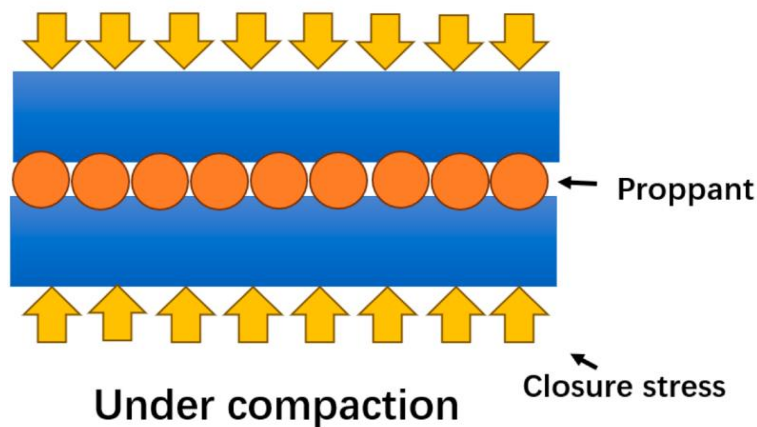
The Technical Side to Drilling

Drilling a well is an extraordinarily complex operation that requires precise engineering thousands of feet below the surface. One of the most important components of this process is **drilling mud**, a mixture of water, clay, and chemicals. It is pumped down the **drill string** or drill pipe and back up the **annulus**, the space between the drill string and the wellbore wall, and serves three purposes. First, it lubricates and cools the drill bit. Second, it applies outward pressure to the underground formation, preventing the well from caving in and preventing a blowout. Third, it circulates drill cuttings back to the surface, clearing downhole so the bit can cut fresh rock. When the drill bit wears out, the crew “**trips out**,” pulling the entire drill string to the surface to swap the bit, then “**trips in**” to resume drilling. Depending on depth, this can take hours or days. To turn the well from vertical to horizontal, the driller uses a **bent motor** or **rotary steerable** system to



angle the wellbore at a controlled rate until it reaches 90 degrees and enters the target formation horizontally.

Once the lateral is completely drilled, a completion/frac crew comes in to complete the well by first **perforating** the casing at specific intervals along the lateral, creating small holes through which fluid can enter the rock. Water, sand, and chemicals are then pumped down the wellbore at extremely high pressure, cracking open the surrounding formation. The sand, known as **proppant**, is carried into those cracks and stays behind once the pressure is released, physically holding the fractures open while leaving enough space for hydrocarbons to flow into the wellbore. This process, known as **hydraulic fracturing** or **fracking**, is performed in stages from the far end of the lateral back toward the surface.



While most wells that are drilled are fracked soon after, some are not completed right away, and these are called **Drilled but Uncompleted Wells (DUCs)**. An operator might postpone a frac job if the commodity pricing environment is low, choosing to wait for higher oil or gas prices before spending the capital to complete the well. Other factors can drive this decision as well: a frac crew or the sand and equipment needed for the job may not be available when drilling finishes, nearby pipelines or gathering systems may lack the capacity to take on additional production, or the operator may simply be pacing spending to stay within a budget. Because completing a DUC is far faster than drilling an entirely new well, this inventory also gives operators flexibility, allowing them to bring wells online quickly once conditions improve rather than waiting through the full drilling process again.

Upstream Accounting Practices

Upstream companies also employ slightly different accounting practices than most companies, specifically in how they treat costs associated with exploration. Two different accounting methods are **successful efforts** and **full cost** accounting. Successful efforts accounting capitalizes (spreading costs in accordance with revenues) only successfully explored wells (meaning that the wells can produce hydrocarbons). Unsuccessful wells (e.g., dry holes) are expensed immediately. This is a

common accounting method employed by larger companies like ExxonMobil, which have large enough balance sheets and income statements that immediately expensing exploration costs will not have a noticeable effect on financial performance. Full cost accounting capitalizes **both successful and unsuccessful wells**. This is generally used by smaller companies that cannot afford to have unsuccessful well costs hit their financial statements all at once.

You will also see differences in how revenue is treated across E&P companies. It is very common to see breakdowns based on the various commodities produced and their associated volumes and revenues. Furthermore, upstream accounting contains many unique line items. **Depletion, Depreciation, and Amortization (DD&A)** is one of the most distinct line items on the income statement, recognizing that each barrel of oil or cubic foot of gas brought to the surface permanently reduces the value of the asset in the ground. **Gain or Loss on Derivatives, Gathering, Processing, and Transportation (GP&T), Lease Operating Expenses (LOE), Production Taxes, and Ad Valorem Taxes** are all additional line items. On the balance sheet, one notable line item is the **Asset Retirement Obligation**, representing the financial burden the operator must take on in the future to shut in a well once it is done producing.

Classification of Reserves

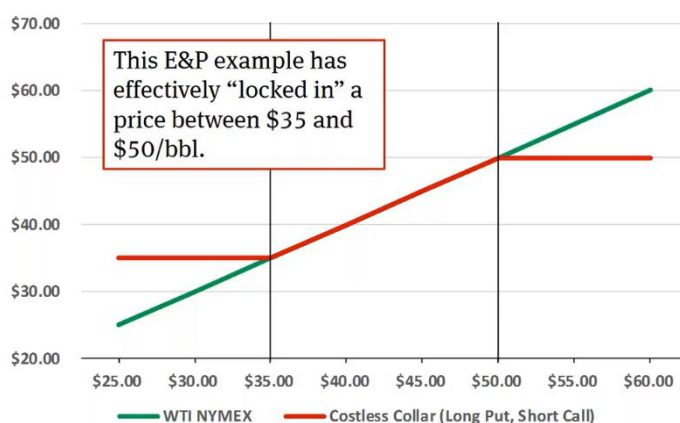
After leasing land, Upstream companies must employ different geological techniques, such as **seismology** (using vibrations to determine rock compositions) and **core sampling** (analyzing rocks pulled from a drilling rig) to understand the size and location of oil and gas **reserves** in a given location. Reserves are important as they determine the ultimate amount of hydrocarbons (and therefore cash flows) that will be recovered. Reserves are classified into three categories: **1P (proved)**, **2P (probable)**, and **3P (possible)**.

1. **1P – Proved:** 1P reserves have a 90% chance of commercial recovery and are the most valuable when determining the value of property or a company.
2. **2P – Probable:** 2P reserves have a 50% chance of commercial recovery and are the second most valuable type of reserves.
3. **3P – Possible:** 3P reserves are the least valuable and least certain type of reserves. They only have a 10% chance of commercial recovery.

Another important concept to know is the difference between **Proved Developed Producing (PDP)**, **Proved Undeveloped (PUD)**, and **Proved Developed Not Producing (PDNP)** wells. PDP wells are those that have already been drilled and are actively producing cash flows; PUD wells are those that can be developed by the company or a potential acquirer in the future; and PDNP wells are those that have already been drilled but are not currently producing.

Hedging Strategies

E&Ps operate in one of the most volatile commodity price environments of any industry, where revenue is almost entirely determined by commodity prices they have no control over. In order to understand the hedging environment, it is important to first understand basic hedging terminology. **Swaps** lock in a fixed price for future production. **Puts** give the producer the right but not the obligation to sell at a minimum price, making them ideal for producers who want downside protection. **Calls** give the buyer the right but not the obligation to purchase at a set price, and while producers do not typically buy calls, they frequently sell them as part of collar structures to offset the cost of purchasing puts (see below for more detail). Because the producer buying the put has the right to choose whether to exercise, while the bank or trading counterparty on the other side must honor the contract regardless of the outcome, the counterparty charges an upfront premium to compensate for that risk.



1. **Fixed-Price Swaps:** The most straightforward and widely used hedging instrument, a fixed-price swap locks in a specific price for a set volume of production over a defined period, with the counterparty paying the producer the difference if the market trades below the fixed price or receiving the difference if the market trades above it. Swaps provide maximum revenue certainty but eliminate all upside participation, meaning a producer fully hedged with swaps in early 2026 would have missed the entire run from \$72 to over \$100 per barrel following the Iran conflict.
2. **Costless Collars:** A collar combines the purchase of a put option, which establishes a price floor, with the simultaneous sale of a call option, which establishes a price ceiling, structured so that the premium paid for the put is offset by the premium received from selling the call, resulting in no net upfront cost. This structure allows the producer to protect against downside below the floor while retaining participation in price appreciation up to the ceiling, and the width of the collar can be adjusted based on where volatility sits in the market.
3. **Put Options:** A standalone put option gives the producer the right but not the obligation to sell their production at a specified strike price, allowing full participation in price increases above the strike while still being protected if prices fall below it. The cost of this flexibility is the upfront premium paid to purchase the option, which has become significantly more expensive in the elevated volatility environment following the Iran conflict.

4. **Three-Way Collars:** A three-way collar works like a normal collar but with one extra piece added to make it cheaper. A standard collar sets a floor, the lowest price the producer is guaranteed, and a ceiling, the highest price it can capture, with prices in between flowing through normally. The three-way collar adds a third leg called a subfloor, set below the floor. The producer gives up some of its downside protection at this level in exchange for cash, and that cash is used to raise the ceiling, so the producer keeps more of the gains if prices rise. The catch is that the floor only protects down to the subfloor, and if prices fall below it, the producer is exposed to the market again.
5. **Basis Swaps:** While the instruments above address outright commodity price risk, basis swaps address a separate but equally important risk: the differential between the benchmark price and the actual price a producer receives at their delivery point. For example, if Henry Hub is trading at \$3.50 but a producer in Appalachia only receives \$2.75 due to regional pricing, that \$0.75 gap is called the basis, and it can widen or narrow significantly over time. A basis swap locks in that gap at a fixed amount, so the producer knows exactly what they will receive at the wellhead regardless of how regional pricing moves relative to the benchmark.

Beyond protecting revenue, hedging also plays a central role in **reserve-based lending (RBL)**, where lenders often require it as a condition of the facility. Under a reserve-based lending facility, a producer's borrowing capacity is sized off the value of its proved reserves rather than conventional cash-flow metrics. Because that collateral value moves with commodity prices, the borrowing base is periodically redetermined as prices and reserves change. To protect against this exposure, many upstream credit agreements, particularly RBL facilities, require borrowers to maintain commodity hedges covering a minimum portion of expected production, often PDP volumes. This safeguards cash flow, debt-service capacity, and collateral value if oil or natural gas prices decline.

Single-Well Model Valuation

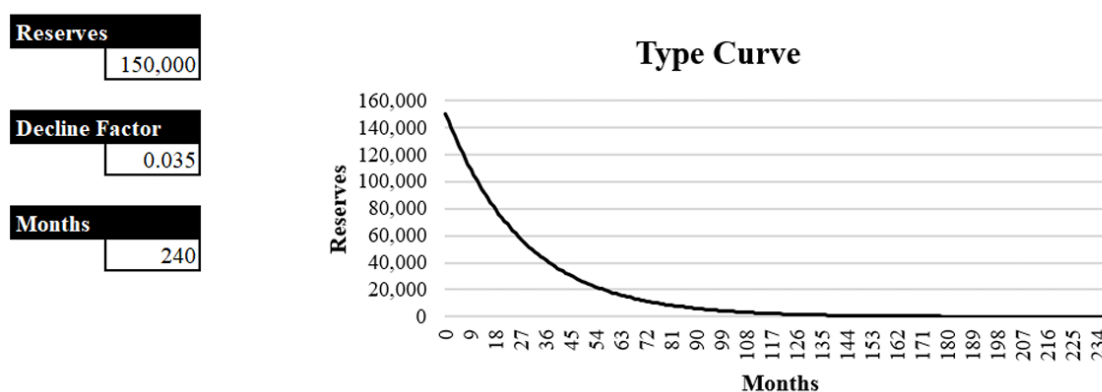
A single-well model projects the production, revenue, and costs of an individual well over its economic life to determine whether drilling it generates an acceptable return on invested capital. Geologists and engineers start by building a type curve, also called a decline curve, that estimates a well's **initial production (IP)** and how quickly its output will fall off over time. These curves tend to be similar for wells in the same region and formation, which makes them a reliable foundation for forecasting. Using the type curve, production for oil, gas, NGLs, and water is projected month by month across the well's entire productive life, beginning from the IP and declining each period thereafter.

Gross production is then converted to net production by applying two ownership adjustments: the **working interest**, the operator's proportional share of the well's costs and ownership, and the **net revenue interest**, the share of revenue left after paying royalties to the landowner. Multiplying net production by the differential-adjusted commodity price gives net revenue. Operating expenses,

including **lease operating expense (LOE)**, water disposal, gathering and transportation, and severance and ad valorem taxes, are then subtracted month by month to arrive at the net cash flow the well generates in each period.

Having completed both the revenue and expense forecasts, analysts can see the stream of cash flows a well will generate once production begins. As with a standard DCF, these cash flows must be discounted back to understand what they are worth today, since a dollar earned years from now is worth less than a dollar earned today. The key difference is that a single-well model does not project cash flows into perpetuity the way a corporate DCF often does, because a well's reserves are a finite asset that depletes and eventually runs dry. A 10% discount rate is common, reflecting the **PV-10** convention, the standard measure used in SEC reserve disclosures. It's worth noting, however, that PV-10 is a standardized *reporting* metric rather than the rate used when valuing an asset: in practice, operators and funds apply a range of discount rates to PDP reserves depending on the specific asset and its risk profile.

Once each period's cash flow is discounted, the discounted values are summed to arrive at the well's **Net Present Value (NPV)**. NPV is a key driver of capital investment because it weighs the present value of every dollar the well is expected to produce against the cost required to drill and complete it. If the NPV is positive, meaning the present value of future cash flows exceeds the present value

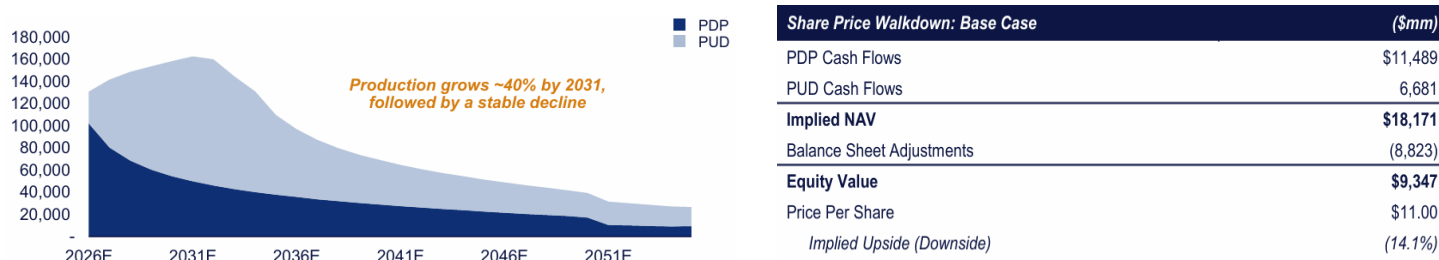


of the cost to develop the well, the well creates value and should be drilled. If it is negative, the capital is better deployed elsewhere. The formula for discounting and summing the well's cash flows is as follows, where t is the period, CF is the cash flow in that period, and r is the chosen discount rate.

Development and Net Asset Valuation Models

After taking the single-well model for each well in a company's portfolio, a **Development Model, or Dev Model**, projects out the company's **PUD** wells over a defined time horizon. Very similar in structure to a single-well model, the development model also does not forecast into perpetuity; however, it applies higher discount rates, such as **PV-15** or **PV-20**, to reflect the greater risk of less-

proven reserves. Unlike a single-well model, a dev model typically shows production increasing in the near term as new wells are brought online, before the overall profile begins to decline as the drilling program slows and existing wells mature. Together, the cash flows from the single-well models and the dev model feed into the **Net Asset Valuation, or NAV** model, where you can then calculate the company's intrinsic valuation.



Comparable Companies Analysis

To assess a company's valuation relative to its peers, analysts select comparable companies based on shared characteristics such as industry, size, geography, operating basin, commodity mix, and reserve life. A multiple expresses value as a ratio to a financial metric. A company trading at 6x EV/EBITDA has an enterprise value equal to six times its annual EBITDA, meaning a buyer pays \$6 of value for every \$1 of EBITDA the business produces. A higher multiple means the market is willing to pay more per dollar of EBITDA, typically reflecting stronger growth prospects, higher-quality or longer-life assets, lower leverage, or lower perceived risk, while a lower multiple implies the inverse. The median or average multiple from the peer group, such as EV/EBITDAX or EV/production, is then applied to the target's corresponding metric to derive an implied valuation reflecting what the market currently pays for similar businesses.

Key Metrics

- EV/EBITDAX: This E&P-specific multiple adds back exploration costs because of the different accounting treatments between the full cost and successful efforts methods.
- P/NAV
- EV/Proved Reserves
- EV/EBITDA

Precedent Transactions

Precedent transactions analysis values a company by reference to the prices paid in past M&A deals involving similar assets. Analysts assemble a set of comparable transactions based on shared characteristics such as operating basin, commodity mix, asset type, and deal size, then examine the

multiples buyers actually paid. Because these are realized acquisition prices, they capture what a buyer was willing to pay for control of the asset, often at a slight premium.

The relevant multiples vary by asset type. For operated E&P assets, buyers commonly use EV/EBITDAX, \$/flowing barrel (price per unit of daily production), and \$/acre (price per net acre of leasehold). For undeveloped inventory, \$/location (price per remaining drilling location) isolates the value assigned to future development. For minerals and royalties, the convention shifts to \$/NRA (price per net royalty acre), since those assets carry no operating or capital costs and are valued on acreage and production interest rather than cash flow after expenses.

As with comparable companies, the median or average multiple from the transaction set is applied to the target's corresponding metric to derive an implied valuation. The key distinction is that precedent transactions reflect prices under the market and commodity conditions prevailing at the time of each deal, so older or off-cycle transactions can be less representative of present value.

Sum of the Parts

Sum-of-the-parts (SOTP) analysis values a company by breaking it into its distinct business segments, valuing each one separately, and adding them together, rather than applying a single multiple or model to the whole. The premise is that a diversified company's segments carry different economics, growth profiles, and risk.

This approach is most applicable to integrated or multi-vertical companies rather than pure-play operators. An integrated major like ExxonMobil, for example, spans upstream, downstream, and chemicals, each of which trades on different metrics and warrants a different valuation approach. Under SOTP, an analyst would value each segment using the metric and peer set specific to that business, such as EV/EBITDAX against upstream peers for the E&P segment and EV/EBITDA against refining peers for the downstream segment to reach an implied valuation.

Leveraged Buyout (LBO)

A leveraged buyout (LBO) analysis values a company by determining what a financial sponsor, such as a private equity firm, could pay while still achieving its target return. The sponsor acquires the company using a mix of debt and equity, uses the company's cash flows to pay down that debt over a holding period of typically three to seven years, and exits through a sale or IPO. The sponsor sets a required rate of return for the deal, and the LBO uses it to back into what the sponsor can pay and still hit that return: the more it pays for the business, the more the company must perform to deliver the target return, while paying less builds in more cushion if performance falls short. This return is usually expressed as an **internal rate of return (IRR)** or a **multiple on invested capital (MOIC)**.

The use of leverage is what distinguishes the approach. Because debt funds a large portion of the purchase price, returns are amplified: as the company generates cash and repays debt, the sponsor's

equity value grows, and a relatively small equity check can produce outsized returns if the business performs. This also makes the LBO a useful floor valuation, since it reflects the price a return-driven buyer could pay, often below what a strategic acquirer with synergies would offer.

How much debt a deal can support varies meaningfully by industry. Businesses with stable, predictable cash flows can carry higher leverage, while more cyclical industries support less. Energy sits in the latter camp: because revenue swings with commodity prices, loading a deal with too much debt becomes risky, as the resulting interest expense can exceed the cash flows the business generates during a downturn.

In an E&P context, the durability and predictability of a target's cash flows matter heavily, since debt service depends on them. Assets weighted toward stable PDP production support more leverage than those dependent on undeveloped reserves requiring significant future capital, and commodity price exposure, often managed through the hedging discussed earlier, directly affects how much debt the business can safely carry.

Offshore Upstream

Overview

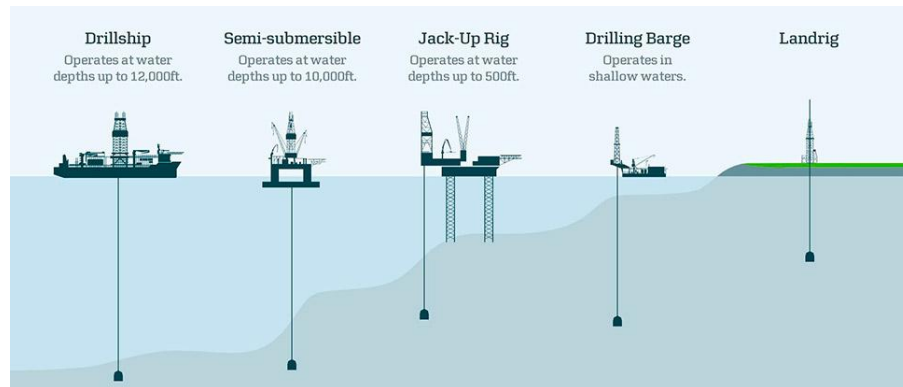
Offshore oil and gas development represents one of the most capital-intensive and technically demanding frontiers in the energy industry. Unlike onshore drilling, which benefits from more straightforward logistics and relatively low-cost infrastructure, offshore work introduces an entirely different set of engineering challenges. Weather, water depth, ocean movement, and the sheer remoteness of the operating environment transform every aspect of the drilling and production process. A single offshore well can cost anywhere from \$25 million to \$1.2 billion, depending on depth, rig type, and complexity, compared to roughly \$15–25 million for an onshore well. Offshore wells also behave very differently from onshore wells once producing. A conventional offshore well produces at a relatively steady rate over a long productive life, often 20 years or more. Onshore unconventional wells follow a much steeper decline curve, with a high initial production rate that falls off sharply in the first few years, so most of the well's value is recovered early even though it may keep producing at low rates for far longer.

Rig Types

Just like in onshore drilling, the rig's purpose is only to drill the well and provide access to the hydrocarbons. Several types of rigs can be utilized to develop offshore assets:

1. **Barges:** The simplest offshore drilling unit, barges operate in 30 to 35 feet of water in sheltered environments like rivers, lakes, and deltas by flooding their hull to rest on the bottom, making them unsuitable for any meaningful wave or current exposure.
2. **Submersibles:** An evolution of the barge concept developed in the late 1950s, submersibles use large buoyancy chambers to lower the rig structure to the seabed at depths of 70 to 175 feet.
3. **Jack-Ups:** The most widely deployed offshore drilling unit in the world, jack-ups mechanically extend legs to the seabed using a rack-and-pinion system to elevate the hull above the waterline, creating a stable drilling platform in up to 500 feet of water.
4. **Semi-Submersibles:** Used in water depths exceeding 500 feet, semi-submersibles flood their pontoon hulls so the bulk of the rig sits below the waterline and out of the wave action zone, making them the preferred choice for rough environments like the North Sea and deepwater.

- 5. Drill Ships:** The most mobile and deepwater-capable unit available, drill ships are ship-hulled rigs that can self-transit to the most remote locations in the world and carry the heaviest equipment.



Major Offshore Regions

- 1. Gulf of America:** One of the most mature offshore provinces in the world, the Gulf of America spans both shallow-water shelf production and ultra-deepwater frontier exploration. It remains one of the most strategically important basins for U.S. energy production.
- 2. North Sea:** A mature but highly active basin shared primarily between the UK and Norway, the North Sea has been a cornerstone of European energy production since the 1970s. Its consistently harsh sea conditions make it one of the primary markets for semi-submersible rigs, and it has taken on renewed strategic importance for European energy security following the loss of Russian pipeline gas.
- 3. Brazil Pre-Salt:** Brazil's pre-salt play, operated primarily by Petrobras in partnership with Shell and TotalEnergies, represents one of the most significant deepwater oil discoveries of the past two decades, with massive reservoirs lying beneath several kilometers of salt deep below the seabed.
- 4. Guyana-Suriname:** Led by ExxonMobil's Stabroek block, the Guyana-Suriname basin has emerged as the most exciting current frontier in offshore oil, with a string of world-class discoveries that have transformed Guyana into one of the fastest-growing oil producers on the planet.

Technical Side to Offshore Drilling

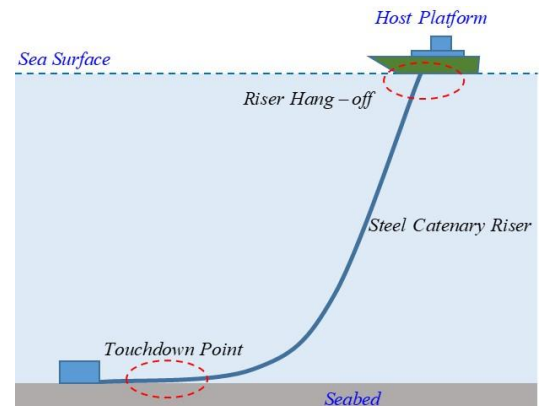
Offshore seismic is operationally simpler than land-based surveys because the vessel continuously tows hydrophone streamers through the water, eliminating the need to manually reposition geophones or drill holes for explosive charges.

1. **The blowout preventer (BOP):** The blowout preventer is the primary safety device for well control. It is a large stack of valves mounted on the wellhead that can seal the well if pressure surges toward an uncontrolled release, or blowout. Ram preventers close around or shear through the drill pipe, while annular preventers seal the space around it. Compared to an onshore BOP, offshore BOPs are larger, rated for higher pressures, and in deepwater they sit on the seafloor rather than at the surface, so they must be operated remotely and are far harder to access and repair than an onshore BOP at the wellhead.



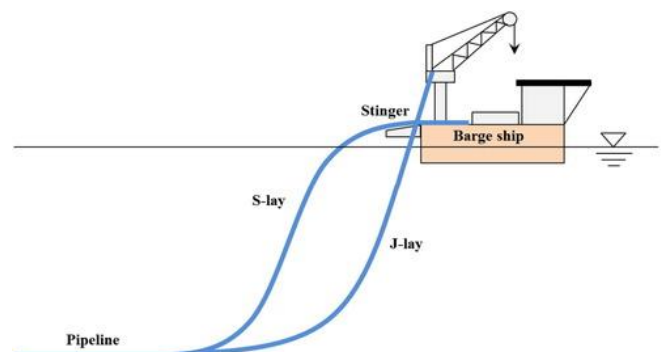
2. **Seabed connection lines:** Once a well is producing, its flow has to be gathered and moved across the seafloor. A subsea tree, a stack of valves, sits on each wellhead and controls flow from the well. Flowlines then carry the oil and gas along the seabed to a central point or toward the production facility, often converging at a manifold that consolidates output from multiple wells before sending it onward. In deepwater, these lines can run for miles across the seabed and are typically insulated or coated to manage heat loss and prevent blockages as fluids travel over long distances.

3. **The riser:** The riser is the pipe that connects the seabed system to the facility on the surface. It carries the produced oil and gas up through the water column. In deepwater, a riser can span thousands of feet from the seafloor to a floating platform. It must be engineered to handle pressure, temperature, and constant motion from waves and currents, as well as risks like vortex-induced vibration and flow assurance issues (hydrate or wax buildup) as fluids cool during the ascent.



4. **Method of laying down subsea pipelines:**

Subsea pipe is installed from specialized vessels using one of three main methods. S-lay welds pipe horizontally and feeds it off the stern, where it bends into an “S” shape as it reaches the seabed; it suits shallow and intermediate water and is generally chosen for its higher installation rate and lower cost in those depths. J-lay welds pipe in a near-vertical position so it enters the water at a steep angle, reducing bending stress on the pipe, which suits



deepwater where an S-lay vessel's horizontal ramp can't reach the seabed without overstressing the line. Reel-lay spools pre-welded pipe onto a large reel onshore and unspools it at sea, which is fast and reduces offshore welding time but is limited to smaller-diameter pipe, making it a good fit when speed and lower offshore labor cost matter more than pipe size.

5. **Umbilicals:** Umbilicals are the control lines that let the surface operate the equipment on the seafloor. Each bundles power, hydraulic, and chemical injection lines into a single sheathed cable. They run from the facility down to the subsea trees and other seabed equipment. Without them, the operator could not monitor or control the wells below.
6. **EPC (Engineering, Procurement, and Construction):** EPC is the standard contract model for building large offshore developments. A single contractor handles the engineering, procures the equipment and materials, and constructs and installs the facility. The operator hands over a defined scope, often at a fixed price, which shifts execution risk onto the contractor. This appeals to operators because offshore projects are massive and complex, so bundling the work under one accountable party simplifies management.

Midstream

Overview

Midstream infrastructure is essential to the energy industry because it enables the movement and storage of hydrocarbons between production, processing, refining, and end-use markets. By connecting upstream producers with downstream consumers, midstream assets facilitate the efficient flow of energy throughout the value chain. Key functions of midstream service providers include:

- 1. Gathering:** Gathering systems transport oil, gas, and water from the wellhead to processing facilities, storage facilities, or long-haul pipelines using low-pressure gathering lines with smaller pipe diameters, often supplemented with field compression to maintain flow. Additionally, gathering pipelines play a critical role in produced water management by moving large volumes of water from the wellhead to disposal, recycling, or treatment facilities. Gathering usually includes clauses related to **minimum volume commitments (MVCs)**, which are commitments made by the producer or shipper to provide a certain volume of products for transportation over a specific period.
- 2. Processing:** At the wellhead, equipment separates the produced stream into oil, natural gas, and water by using differences in pressure, density, and gravity. The natural gas is then transported to processing plants where impurities are removed, and the gas is separated into pipeline-quality dry gas and NGLs. Once processed, dry gas can be transported through interstate pipelines, while NGLs are sent to fractionation facilities for further separation. Processing agreements may include clauses related to **minimum processing volumes (MPVs)**, which are similar to MVCs and provide a guaranteed volume of products to be processed over a specific period.
- 3. Transportation:** Transportation pipelines are long-haul systems designed to move large volumes of crude or gas over significant distances, often across state lines, which brings regulatory oversight from the **Federal Energy Regulatory Commission (FERC)**. These agreements may include clauses related to **take-or-pay** commitments, which are obligations to pay for a specified amount of transportation capacity, regardless of whether the shipper or customer uses it.



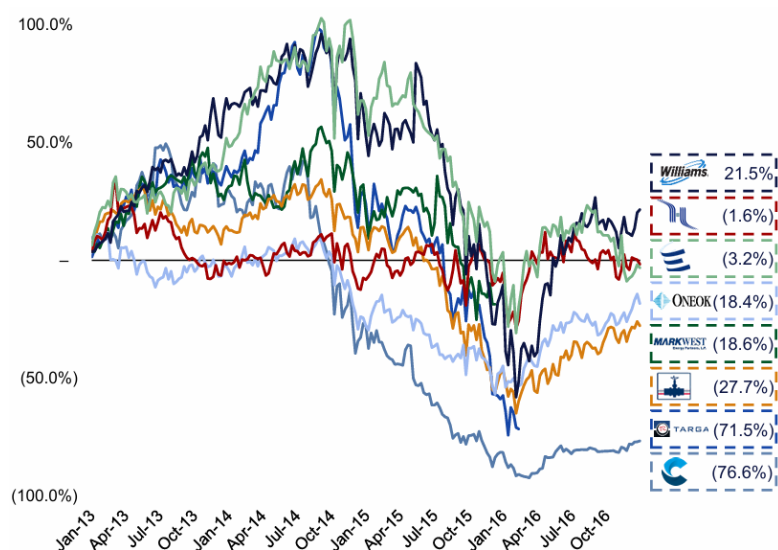
4. **Fractionation:** Once the NGLs have been separated from dry gas, they are transported to a fractionation facility where heat and pressure are used to separate the mixture into its individual components based on their different boiling points. Each product that comes out of the fractionator, including **ethane, propane, and butane**, has its own distinct market price and end use, ranging from petrochemical feedstocks to cooking fuel.
5. **Storage:** These contracts govern the storage of oil and gas products in storage facilities. Storage agreements may include provisions for the storage fee. Storage agreements may include clauses related to **minimum storage volumes (MSVs)**, which are similar to MVCs and provide a guaranteed volume of products to be stored over a specific period.
6. **Marketing:** Marketing refers to buying and taking title to the hydrocarbons from producers at the wellhead and reselling them at a higher price to end users. Unlike pure fee-based midstream services where the company earns a fixed tariff regardless of commodity prices, marketing involves direct commodity price exposure, as the midstream marketer's profitability depends on successfully capturing the spread between the purchase and sale price.

MLPs

A master limited partnership (**MLP**) is a publicly traded partnership that combines the tax benefits of a partnership with the liquidity of a publicly traded security. MLPs are structured around two classes of ownership: **the general partner**, which manages the day-to-day operations of the business and typically holds a **2%** economic interest, and the **limited partners**, who are the public unitholders that provide capital and receive the majority of the cash distributions but have no role in management. A critical feature of the general partner's economics is the **Incentive Distribution Right (IDR)**, which entitles the general partner to an increasingly larger share of incremental cash distributions as the MLP hits certain payout thresholds, aligning the general partner's incentives with distribution growth.

From a tax perspective, MLPs pass through their income directly to unitholders without paying corporate-level taxes, meaning investors receive a K-1 tax form rather than a standard 1099 and are taxed at their individual rate. A significant portion of MLP distributions are typically considered a return of capital rather than ordinary income, which defers the tax liability until the unitholder sells their units, making MLPs particularly attractive to investors seeking a tax-advantaged investment. However, this same tax structure creates complications for institutional investors such as pension funds, endowments, and certain mutual funds, as MLP ownership can generate unrelated business taxable income, known as UBTI, which subjects otherwise tax-exempt investors to unexpected tax liabilities and has historically limited the institutional capital available to the MLP market.

The MLP Collapse



MLPs were built on a model that paid out nearly all of their free cash flow as distributions to unitholders, which meant that any capital needed for growth or acquisitions had to be raised by issuing new equity or taking on debt. The structure was further complicated by incentive distribution rights, which entitled general partners to capture up to 50% of incremental cash flows as distributions grew, raising the cost of equity and requiring that any new project generate returns high enough to compensate both the LP and the GP. This worked as long

as capital markets remained open and cheap, but when oil prices collapsed between 2014 and 2016, investor appetite for new MLP equity dried up, and lenders tightened credit, cutting off the funding the model depended on. MLPs that had already committed to large capital projects were suddenly stuck with expensive backlogs they could not finance, high debt levels they could not service, and distributions they could not sustain, forcing widespread cuts that sent unit prices sharply lower and permanently damaged investor confidence in the structure. Kinder Morgan was the first to act, reorganizing in 2014 by consolidating two publicly traded MLPs and an LLC into a single corporation and simultaneously eliminating its IDRs. The crisis ultimately drove a broader shift where companies lowered payout ratios, built higher distribution coverage, and committed to funding growth entirely from internally generated cash flow rather than relying on capital markets. ONEOK and Targa are prominent examples of former MLPs that followed a similar path, converting into single C-corporations and eliminating the general partner and limited partner conflicts that had defined the old structure.

Water Infrastructure

Every well produces water that must be trucked, handled, and disposed of under state regulations. This has grown in importance as unconventional wells across the U.S. mature, because a well's water-to-oil ratio rises over time, so an aging shale well yields steadily more water for every barrel of oil it produces. A single unconventional well in the Permian Basin can require millions of gallons of water during the completion process alone, and that same well will produce increasing volumes of saltwater, known as produced water, throughout its lifecycle. Managing this water efficiently has become a significant operational and financial consideration for upstream operators, giving rise to a dedicated water midstream sector that mirrors the traditional gathering and transportation business in structure,

contract type, and investment profile. Below, we will cover the four main sections of water infrastructure.

1. **Water Sourcing and Supply:** Before a well can be fracked, operators must secure a reliable water supply at sufficient volumes to execute the completion. Sources include surface water drawn from rivers and lakes, groundwater extracted from freshwater aquifers, municipal water supplies, and recycled produced water from existing wells. Water supply pipelines are typically lower-pressure systems constructed from high-density polyethylene or coated steel, as they are moving large volumes of non-pressurized fluid rather than hydrocarbons under reservoir pressure.
- 
2. **Produced Water Gathering:** Once a well begins producing, it generates substantial volumes of saltwater alongside hydrocarbons that must be collected, transported, and either disposed of or treated. In mature fields, produced water volumes can exceed oil volumes by a ratio of five to one or more. Gathering systems operate at relatively low pressure since fluid moves by gravity or pump rather than reservoir pressure, but the highly saline and corrosive nature of produced water requires specialized pipe coatings and materials.
 3. **Saltwater Disposal:** The most common method of produced water disposal is injection into licensed saltwater disposal wells, deep formations permitted to permanently store the water in geology isolated from freshwater aquifers. The economics are driven by volume throughput and per-barrel disposal fees charged to operators, typically ranging from \$0.25 to over \$1.00 depending on location and competitive dynamics.
 4. **Produced Water Recycling:** As freshwater scarcity has intensified and regulatory pressure on disposal has increased, produced water recycling has grown significantly as an alternative to outright disposal. Treatment facilities remove solids, hydrocarbons, bacteria, and dissolved salts so the water can be reused in hydraulic fracturing, reducing an operator's dependence on freshwater sourcing and lowering disposal costs. Full desalination to potable standards remains uneconomic, but investment in reusing produced water for agricultural and industrial purposes beyond the oilfield is accelerating as the regulatory and economic environment evolves.

Current Permian Midstream Constraints

Because the Permian Basin was developed primarily as an oil play, pipeline infrastructure was built to move crude, leaving natural gas takeaway capacity severely constrained. When oil wells come online, associated gas is produced as an unavoidable byproduct, and without sufficient pipeline

capacity to move it, operators are often left with no choice but to **flare**, or burn off gas, at the wellhead, wasting the resource entirely. This supply glut with nowhere to go is why the **Waha Hub**, the primary natural gas pricing point in West Texas, frequently trades at a steep discount to Henry Hub and has at times gone deeply negative, meaning producers are effectively paying someone to take their gas.



However, the infrastructure landscape is beginning to shift, driven by two powerful demand tailwinds: growing LNG export capacity along the Gulf Coast that requires significant volumes of natural gas to feed export terminals, and surging AI data center construction that is driving electricity load growth and pulling incremental gas demand from power generators across the country. These tailwinds are beginning to justify the economics of new Permian gas pipeline projects, and a meaningful buildout of takeaway capacity is underway that should gradually close the gap between supply and the infrastructure needed to move it to market.

Valuation

Key Metrics

- Distributable Cash Flow: EBITDA – Interest Expense – Taxes – Preferred Dividends – Maintenance Capex +/- Distributions to other entities
- Distribution Yield: Distributions / Equity Value
- EV/EBITDA

Common Methodologies

- Dividend Discount Model
- DCF
- Precedent Transactions
- Comparable Companies Analysis
- Sum of the Parts
- LBO

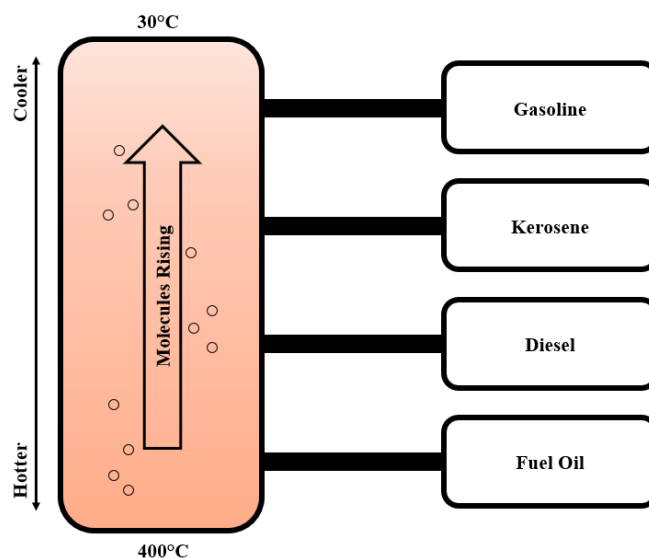
Downstream

Overview

Downstream is the final segment of the oil and gas value chain, responsible for converting crude oil into the finished products that power economies and daily life. Refiners buy crude oil and process it in **refineries**, which are very capital-intensive industrial facilities, requiring billions of dollars in upfront investment and designed to run continuously with lifespans of 30 to 50 years. The business model is built on the margin between what a refiner pays for crude and what it receives for its finished products, making the spread rather than the absolute level of commodity prices the primary driver of profitability. No new refinery has been built in the United States since 1976, and environmental regulations make greenfield construction effectively impossible in most developed markets, meaning growth in refining capacity comes almost entirely from expansions and upgrades to existing facilities.

The Refining Process

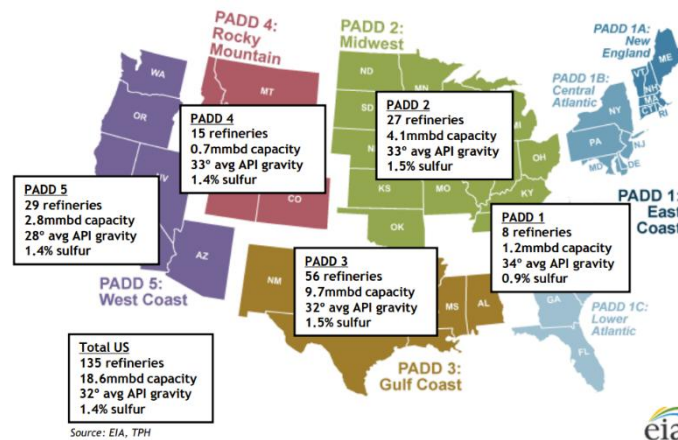
Crude oil is the raw input to the refining process. Oil is heated in a **distillation tower**, where it is separated into different fractions based on boiling point. Lighter products such as gasoline and naphtha vaporize and rise to the top of the tower, while heavier products such as diesel, fuel oil, and asphalt remain lower or settle at the bottom. Complex refineries can produce a higher proportion of valuable light products like gasoline and diesel than simple refineries because they add cracking units, which can take the heavy residual products that settle at the bottom of the distillation tower and convert them into lighter, more valuable products rather than selling them as low-value fuel oil or asphalt. The extent of this refining capability is measured by the **Nelson Complexity Index (NCI)**. A higher NCI means the refinery can process a wider range of crude inputs and extract more value from each barrel. Light sweet crude naturally yields more gasoline and distillates and is cheaper to refine, while heavy sour crude requires more complex refining.



Refined Products and Profitability Drivers

Refineries produce a range of products serving distinct end markets. Gasoline is the largest volume product and the primary fuel for passenger vehicles. Diesel powers trucks, trains, ships, and heavy

equipment. Jet fuel powers commercial aviation, and naphtha and LPG serve as petrochemical feedstocks. Refinery profitability is captured by the **Gross Refinery Margin (GRM)**, which measures how much a refinery earns per barrel by subtracting the cost of crude and refining from the combined value of all the products it produces. A simplified version of this concept is the **crack spread**. The most common formulation is the **3:2:1** model, which assumes three barrels of crude produce two barrels of gasoline and one barrel of distillate. Traders and refiners use it as a quick read on refining margins. A wider spread signals strong margins and encourages refiners to run harder, while a narrower spread signals weak margins and can lead them to cut runs.



The key profitability drivers are **location, complexity, size, and choice of crude**.

1. **Location:** A refinery's location, and the level of local competition that comes with it, drives several key costs: crude freight, product dispatch, the prices it can charge for its products, and compliance with labor and environmental rules. The main distinction is between coastal and inland plants. Where an inland refinery is the dominant or sole supplier to a local market, less competition lets it capture a higher margin. This has been especially clear in the U.S. Midwest (PADD 2), where inland refineries buy discounted crude piped down from Canada and the Bakken, sell into a region that is short on refining capacity, and earn wider margins than coastal refineries paying global prices for waterborne crude.
2. **Complexity:** A refinery's complexity refers to the extra processing units it adds after the initial distillation step, and it determines both what products the refinery can make and what crude it can run. Simple refineries are stuck with a fixed output mix and rely on expensive light, sweet crude, while complex refineries use units like crackers and hydrotreaters to turn cheaper, heavier crude into more valuable products like gasoline and diesel while producing less low-value fuel oil. This flexibility lets complex refineries buy discounted crude and still meet the strict fuel standards that simple refineries often cannot.

Figure 249: Typical Western Europe Product Yields: Simple vs. Complex

Product	Simple Refinery	Complex Refinery
Liquid Petroleum Gas	4%	6%
Naphtha	10%	10%
Gasoline	14%	26%
Kerosene	17%	16%
Gasoil/ Diesel (aka middle distillates)	20%	23%
Fuel Oil	35%	19%

Source: Deutsche Bank

3. **Choice of Crude:** Light sweet crudes like Brent and WTI trade at a premium to heavy sour blends like Russian Urals or Mexican Maya, and in theory the size of that premium should simply equal the difference in value of the products each crude produces. In tight markets, though, the premium widens beyond that because refiners that can only run light crude are forced to compete for a limited supply of it, pushing its price even higher. This means a refinery able to process heavy crude effectively earns a bonus for that flexibility, buying its crude at a discount larger than the difference in the crude's actual product value would justify.

Figure 291: Comparison of yields for typical oil crops

Crop	Yield (litres of oil per hectare)
Algae	100,000
Palm	5,950
Coconut	2,689
Castor	1,413
Sunflower	952
Soy	446

Source: Oligae.com

Biofuel

Biofuels are fuels made from biomass, meaning recently living plant or animal material such as corn, sugarcane, soybeans, or vegetable oils, rather than from crude oil. They sit within the downstream space because they are blended into or substituted for the same refined products that refineries produce. Biofuels remain a small share of the global energy mix, but production has grown steadily for two decades, driven almost entirely by government policy rather than by the underlying economics of the fuels themselves.

Making bioethanol costs roughly \$0.40 per liter on a global average basis and as much as \$0.75 per liter in higher-cost regions like the EU, compared to gasoline refined from \$50 oil at around \$0.31 per liter. However, government support via tax credits, blending mandates, and tradeable compliance credits can make the renewable fuel market economically viable despite this cost disadvantage.

Of these support mechanisms, the most important in the United States is the Renewable Fuel Standard, which works through credits called **Renewable Identification Numbers (RINs)**. The government requires every large refiner to blend a set amount of biofuel into the fuel supply each year, and a RIN is a receipt proving that a gallon of biofuel was blended. Refiners that blend biofuel themselves earn the RINs they need, while those that cannot blend must buy RINs from someone who did, which is what gives them a tradeable market price. This makes RINs a bonus revenue stream for blenders and a real cost for refiners without blending capacity. Because RIN prices rise and fall with government decisions, such as raising or lowering the annual blending requirement or exempting small refiners from it, they can move a refiner's annual compliance cost by hundreds of millions of dollars.

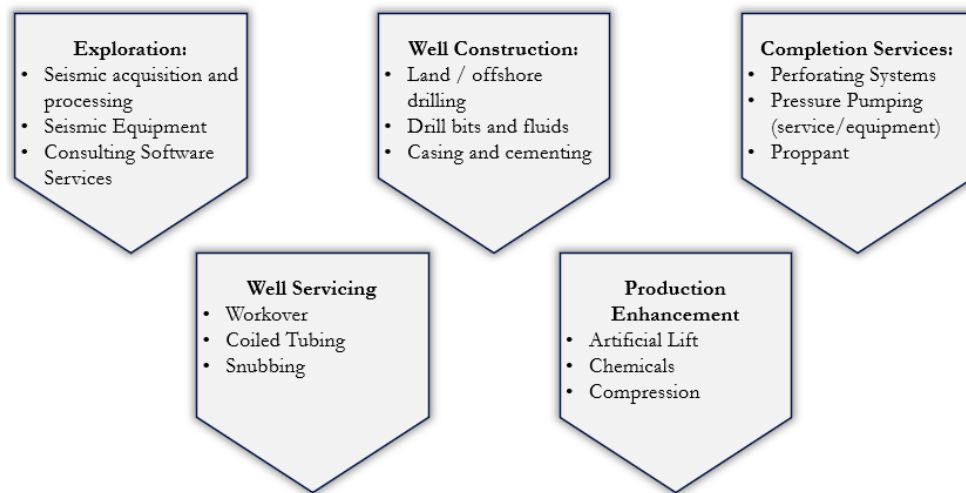
Valuation

- Comparable Companies Analysis
 - EV/EBITDA & FCF Yields are key
- Precedent Transactions
- Sum of the Parts
- Discounted Cash Flow Analysis

Oil Field Services (OFS)

Overview

The oil field services sector provides infrastructure, equipment, and services that are necessary for the exploration and production of oil and natural gas. E&P companies rely on OFS companies for a range of services, **from initial geophysical and geological studies to completion & production services.**



The Technical Side to OFS

In the onshore exploration phase, oil field services companies provide seismic surveys and geological studies that help E&Ps identify potential reservoirs, giving operators critical information on subsurface rock structure before a single dollar is spent on drilling.

OFS companies also provide the critical tools and data to allow the operators to create the wells, allowing hydrocarbons to flow to the surface. One of the most critical roles of OFS companies is in the **completion and stimulation phase of wells**. Once the well has been drilled, **perforating guns** are lowered down the wellbore, detonating shaped charges at precise intervals along the casing to create the openings through which fracturing fluid will enter the formation. The frac stack, a specialized assembly of valves and pressure control equipment at the wellhead, manages the enormous pressures generated by dozens of high-horsepower pumping trucks forcing water, sand, and chemicals into the rock at rates sufficient to crack it open. The oil field services industry is made up of a diverse range of companies, from large international players such as **Schlumberger**,



Halliburton, and Baker Hughes to smaller, independent firms that specialize in particular types of products and services.

The OFS space is widely considered to be the **riskiest vertical** of the oil and gas value chain because its revenue primarily depends on the capex budgets, active number of drilling rigs, and overall development activities of upstream companies. Thus, when oil prices fall and capex budgets are curtailed, the oil field service space is the first to feel the negative effects.

OFS Power Generation

In recent years, oil field services companies have begun to build on their traditional role, extending beyond the drilling, completion, and stimulation services that have long defined the vertical and into **behind-the-meter** power generation for data centers: natural gas-fired generation sited directly at the facility that bypasses the grid entirely. The catalyst has been artificial intelligence: surging electricity demand from data centers has outpaced what the grid can deliver, pushing hyperscalers to look for power independent of the grid. OFS shifting into behind-the-meter power proved to be a natural adjacency for some of the large OFS companies, which already possessed the equipment, gas expertise, and project execution capacity that behind-the-meter generation required, and importantly, a growth avenue independent of upstream drilling activity.

Baker Hughes has moved most directly, leaning on its turbomachinery franchise. It booked roughly \$1 billion in data center orders in its Power Systems line in the first quarter of 2026 alone, matching its total for all of 2025, and has since signed a multi-year agreement with Kodiak Gas Services for approximately 1 GW of capacity. Halliburton entered a partnership with VoltaGrid, securing manufacturing capacity for 400 MW of modular power systems. SLB has shipped more than 1.3 GW of infrastructure for data center projects since April 2024, with cumulative deliveries expected to exceed 2 GW by year-end 2026. Finally, Liberty Energy, historically a pure-play frac and wireline provider, entered a July 2026 strategic alliance with SLB pairing modular infrastructure with integrated gas-fired generation.

Valuation

- Comparable Companies Analysis
- Precedent Transactions
- Discounted Cash Flow Analysis
- Sum of the Parts

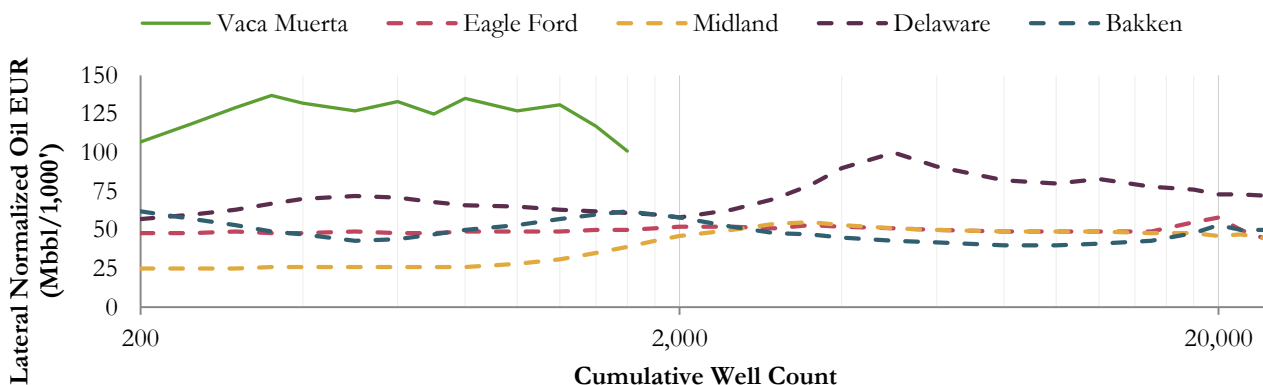
International Development

Overview

The global oil and gas industry has undergone a significant geographic shift over the past two decades, with developing nations emerging as some of the most important new sources of supply. Improvements in deepwater drilling technology, more favorable fiscal regimes, and a wave of major discoveries have drawn supermajor capital away from mature basins and toward frontier markets where large, untapped reserves justified the complexity and risk. Countries once considered too risky, too remote, or too geologically uncertain have become central to the global supply outlook, with national oil companies and international majors alike racing to stake their positions. While many countries across the Middle East, Southeast Asia, and East Africa are developing their resource bases at a rapid pace, the following analysis focuses on six of the most consequential production stories: Argentina, Australia, Brazil, Canadian Oil Sands, Guyana, and Qatar's North Field Expansion.

Country/Region Descriptions

1. **Argentina:** The **Vaca Muerta** formation holds an estimated 308 trillion cubic feet of gas and 16 billion barrels of oil and condensate, making Argentina home to the fourth-largest shale oil and second-largest shale gas reserves in the world, spanning a total area three times the size of the Permian Basin with only a fraction of the acreage currently under development. The formation sits within the Neuquén Basin, historically Argentina's most important producing region and the source of roughly 45% of the country's oil and nearly 60% of its gas, giving operators an established base of infrastructure and processing capacity to build from. For much of the last two decades, development was held back by the legacy of the 2002 economic crisis and the price controls that followed, which froze domestic gas prices and pushed a once self-sufficient country into costly reliance on subsidized LNG imports, leaving little incentive for the heavy investment shale development requires. When Javier Milei, Argentina's current president, took office in December 2023, he inherited 211% annual inflation, and since then he has enacted strict fiscal policies that have lowered inflation to roughly 31%, appealing to foreign investors and fueling accelerating capital commitments into the Vaca Muerta.

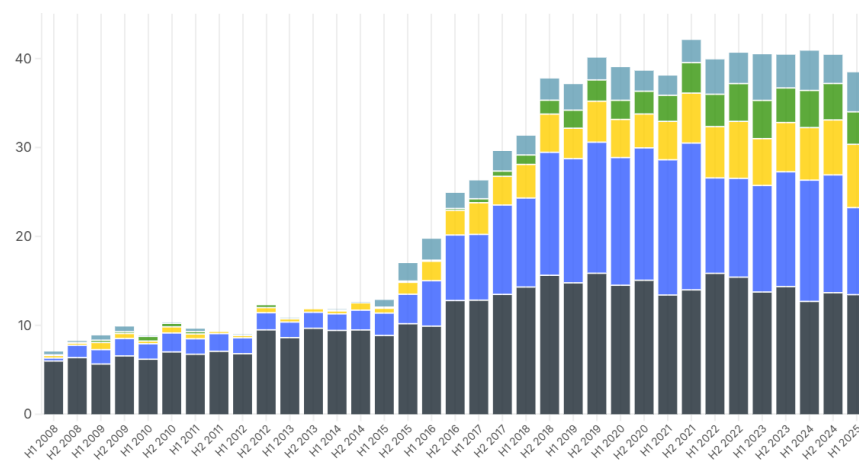


2. **Australia:** Australia established itself as a global LNG exporter through major offshore development across its key producing basins, including the Carnarvon Basin off Western Australia, which alone holds roughly two-thirds of the country's gas reserves, along with the Browse and Bonaparte Basins in the northwest. Backed by projects like the North West Shelf Venture and the giant Gorgon and Wheatstone developments, Australia scaled its liquefaction capacity rapidly enough to become one of the largest LNG exporters in the world, ideally positioned to supply the gas-hungry markets of Asia. The bulk of Australia's reserves are gas rather than oil, with liquids production having peaked in 2000 and steadily declined since, leaving the country reliant on gas-associated condensate and on imported refined products to meet its own demand. An emerging play is the **Beetaloo Basin** in the Northern Territory, recognized as one of the largest and most significant shale gas plays globally with more than 500 trillion cubic feet of discovered and prospective gas resources, potentially rivaling the Marcellus Shale in the United States, with first gas expected to flow in the second half of 2026.

Australia's LNG exports by destination country

■ Japan ■ China ■ South Korea ■ Taiwan ■ Other

Million tonnes



Source: Kpler.

Institute for Energy Economics
and Financial Analysis

3. **Brazil:** Brazil's transformation into a major global oil producer has been built almost entirely on the pre-salt offshore play, where Petrobras has developed a series of giant fields in ultra-deepwater beneath thick layers of salt in the Santos and Campos basins. These reservoirs sit thousands of meters below the seabed under a salt seal that traps large volumes of high-quality crude, and although they are technically demanding and capital intensive to develop, requiring extensive use of floating production vessels, their sheer scale has driven sustained production growth. That growth has scaled dramatically, with January 2026 data showing average output of 3.95 million barrels of crude per day, a 14.6% increase over the prior year. Brazil is now on track to lift five million barrels per day by 2030, positioning it as a top-five global producer.
4. **Canadian Oil Sands:** Canada's oil sands represent the largest single petroleum deposit in the world, with up to 2.5 trillion barrels of **bitumen** in place and roughly 170 billion barrels

considered recoverable. A key advantage of the oil sands is that, due to different extraction techniques, reserve lives are measured in decades, which makes it a haven for producers seeking long-term, low-risk production. Unlike conventional crude that flows or is pumped from the ground, bitumen is too heavy and viscous to extract conventionally and must instead be either **surface-mined**, which is viable up to 75 meters, or recovered in place through in-situ methods like **steam-assisted gravity drainage (SAGD)**, which uses paired horizontal wells to inject steam and drain the heated bitumen and accounts for the majority of recoverable reserves. The bitumen itself is low-value, selling at a steep discount to WTI because its very low API gravity requires either specialized refineries or expensive upgraders that break it down into a lighter synthetic crude (syncrude) suitable for conventional refining.

5. **Guyana:** Guyana went from having virtually no oil production to becoming one of the fastest-growing producers in the world following ExxonMobil's discovery at the Stabroek block in 2015, which has since yielded more than 30 significant finds with recoverable resources now estimated at least 11 billion barrels. By late February 2026, Guyana was lifting roughly 926,550 barrels per day, making it South America's second-largest oil producer behind Brazil and ahead of Venezuela. The Stabroek block is operated by ExxonMobil with a 45% interest, alongside Chevron at 30% (acquired through its purchase of Hess) and China's CNOOC at 25%, with total production capacity expected to reach 1.7 million barrels per day across eight developments by 2030. The country's small population of under one million means oil revenues have the potential to fundamentally reshape the Guyanese economy, though governance and equitable wealth management remain active concerns for investors monitoring its long-term trajectory.

6. **Qatar's North Field Expansion:** Qatar's North Field expansion, the world's largest natural gas field, is being scaled up through the North Field East and North Field South projects, set to lift Qatar's LNG export capacity from roughly 77 million tonnes per year to around 142 million tonnes by the late 2020s, cementing it as the top or near-top global LNG exporter. This puts Qatar in direct competition with the United States, whose Gulf Coast terminals (Plaquemines, Corpus Christi Stage 3, Golden Pass, and others) have driven a parallel wave of LNG capacity growth and made the U.S. the world's largest LNG exporter in recent years.



Power and Utilities

Overview

The Power and Utilities sector is responsible for generating electricity and delivering it to homes, businesses, and industrial facilities by converting fuel sources such as natural gas, coal, nuclear, wind, and solar into electricity and transmitting it across a network of high-voltage transmission lines and lower-voltage distribution systems.

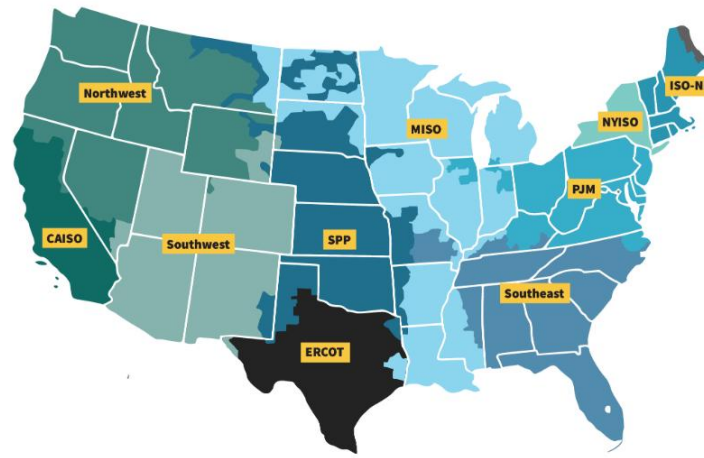
The utility business model is built on regulation rather than commodity exposure. Most traditional utilities operate as **regulated monopolies** within a defined geographic territory, meaning they have no competition but must have their rates approved by state public utility commissions. The regulator allows the utility to earn a set return on its invested capital, known as the allowed return on equity, which typically ranges from 9% to 11%. That invested capital is called the rate base, and it represents the value of the assets the utility uses to serve customers, such as power plants, transmission lines, and substations. Because the utility earns its allowed return on the rate base, the primary way it grows earnings is by growing the rate base through capital investment, which is why utilities spend heavily on projects like grid modernization, new transmission, and renewable generation. This makes utility earnings highly predictable and relatively insensitive to commodity prices, since fuel costs are generally passed through to ratepayers rather than absorbed by the utility itself.

The power sector is divided into three distinct functions. **Generation** is the production of electricity from a fuel source, whether a natural gas plant, nuclear reactor, coal plant, or renewable asset. **Transmission** moves that electricity at high voltage over long distances from where it is generated to where it is needed. **Distribution** steps the voltage down and delivers it through local networks to end consumers. Vertically integrated utilities own and operate all three functions within their service territory, while in deregulated markets these functions are separated and operated by different companies competing in wholesale power markets.

U.S. Electric Grid Overview

The U.S. electric grid is divided into three major interconnections: the Eastern **Interconnect**, the **Western Interconnect**, and the **Electric Reliability Council of Texas (ERCOT)**, which operate largely independently with limited ability to transfer power across their boundaries. Within each interconnection, the grid is further divided into regions managed by **Independent System Operators (ISOs)** and **Regional Transmission Organizations (RTOs)**. Both serve as independent entities that do not own generation but instead manage the flow of electricity across the grid, run wholesale power markets, and ensure reliability across their regions. Major ISOs and RTOs include **PJM** in the Mid-Atlantic and Midwest, **MISO** across the central U.S., **CAISO** in California, **NYISO** in New York, **ISO-NE** in New England, and **ERCOT** in Texas. Approximately two-thirds

of U.S. electricity load is served by these ISO/RTO-operated markets, while the remaining third is served by vertically integrated utilities, primarily in the Southeast and Mountain West, where a single company owns and operates the entire system.



Power Generation

Power generation is the process of converting a fuel source or natural resource into electricity, most commonly by using heat to produce steam that spins a turbine connected to a generator, which then produces an electrical current. The major generation sources are **natural gas, coal, nuclear, wind, and solar**, each with distinct cost structures, operating characteristics, and roles within the power system. Natural gas plants are the most flexible generation source, able to ramp output up and down quickly in response to demand fluctuations, making them the dominant source of what is called **peaking power** during periods of high electricity demand. Coal plants are cheaper to operate on a fuel cost basis but are slower to ramp and face increasing regulatory pressure due to emissions. Nuclear plants produce large volumes of carbon-free power around the clock but are extremely capital-intensive to build and carry unique safety and waste management considerations. Wind and solar are the fastest-growing generation sources, with effectively zero fuel cost once built, but their output is intermittent and dependent on weather conditions, creating reliability challenges that require either backup generation capacity or battery storage to manage.

The mix of generation sources on a given grid at any point in time is called the **generation stack**, and the order in which plants are dispatched to meet demand is determined by their marginal cost of production, with the cheapest sources running first and more expensive peakers called on only when demand rises high enough to require them.

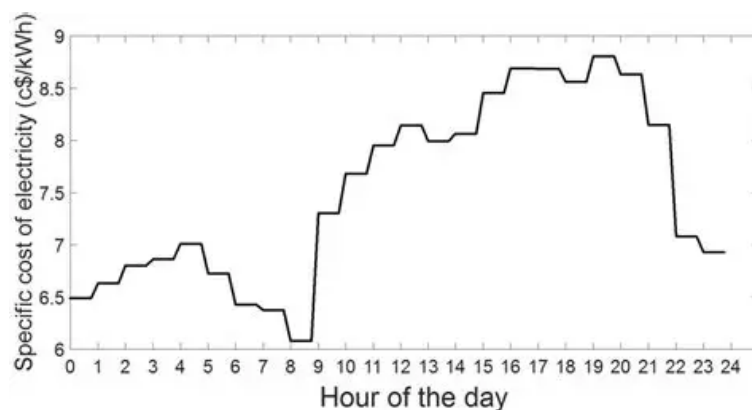
Transmission and Distribution

Once power is generated, it travels through transmission lines at high voltages, typically 230 to 765 kilovolts, over long distances before being stepped down at substations to lower distribution-level

voltages for local delivery to homes and businesses. The wires that carry electricity are always regulated monopolies. Because duplicating transmission and distribution infrastructure to the same area would be economically inefficient, a single company owns and operates the network under government oversight with guaranteed cost recovery. Generation is different. In competitive states, multiple power plants bid against each other to sell electricity into wholesale markets. Not all generation is owned by utilities. **Independent Power Producers (IPPs)** own and operate power plants but sell electricity into wholesale markets or under long-term contracts. Unlike regulated utilities, which earn a predictable regulated return, IPPs are fully exposed to wholesale electricity prices and fuel costs, meaning their cash flows can swing dramatically depending on market conditions.

Electricity Pricing

In regulated states, utilities plan and build generation, recover their capital costs through rates, and pass fuel costs directly to customers. In competitive markets, ISOs run wholesale auctions where power plants bid to supply electricity and the lowest-cost generators win.



In these competitive markets, electricity is priced using **Locational Marginal Pricing, or LMP**. The price at any given point on the grid reflects the cost of generating the next megawatt of power, plus the cost of moving it through congested transmission lines, plus line losses. Markets clear continuously, and the day-ahead market schedules generation one day out, while the real-time market rebalances every five minutes as actual

conditions deviate from the forecast. Electricity demand follows predictable daily and seasonal patterns, ranging from roughly 400 to 700 gigawatts nationally, with summer peaks driven by air conditioning, winter peaks by heating, and softer shoulder seasons in spring and fall.

Texas Power Failure

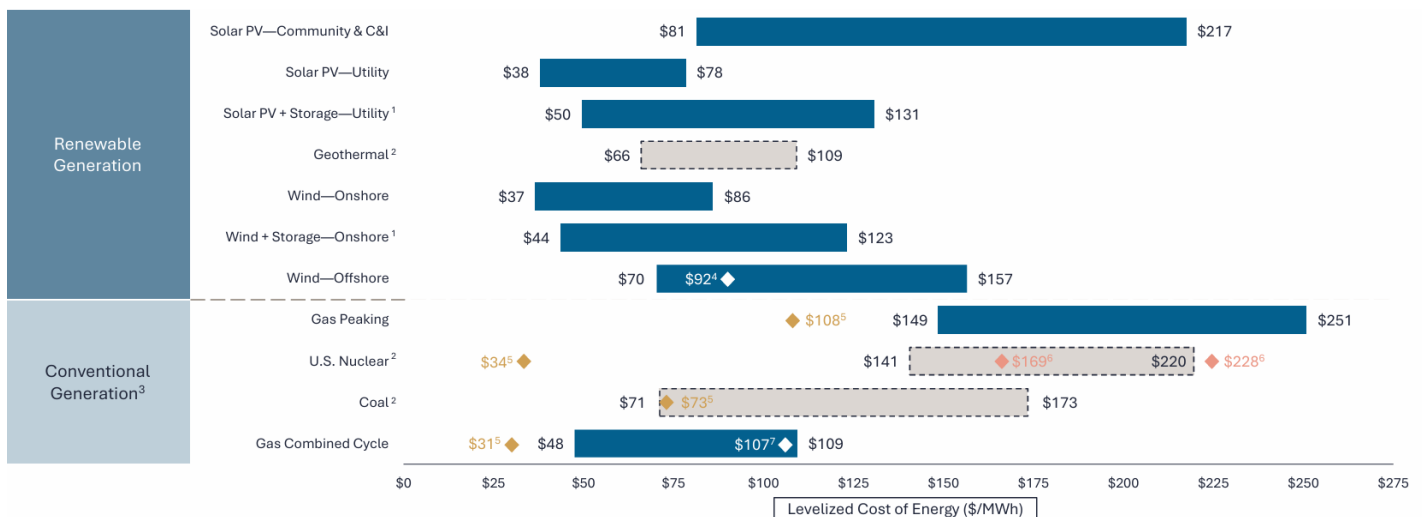
In February 2021, a severe winter storm exposed the structural vulnerabilities of ERCOT's isolated design. Natural gas pipelines froze because wellheads and processing equipment had not been weatherized for extreme cold, cutting off fuel supply to gas-fired plants at precisely the moment demand was surging. Wind turbines tripped offline, coal and nuclear plants suffered cold-weather outages, and gas plants that still had fuel access could not operate without it, causing roughly a third of Texas's total generation capacity to go offline simultaneously. With supply collapsing and demand spiking as Texans ran heaters at full capacity, wholesale power prices hit the \$9,000 per MWh market

cap and held there for several consecutive days. A retail electricity customer on a variable-rate plan who would normally pay around \$50 per MWh received bills in the tens of thousands of dollars for a single week of usage. More than 4.5 million customers lost power, dozens of people died from hypothermia and carbon monoxide poisoning as residents resorted to burning charcoal indoors for heat, and economic damages reached an estimated \$100 billion. Because ERCOT operates as an isolated grid with virtually no connections to neighboring systems, there was no ability to import power from outside Texas to cover the shortfall, a design that prioritizes independence from federal regulation but eliminates the mutual aid that interconnected grids can provide during emergencies.

Capacity Factor and LCOE

Overview

Capacity factor measures the percentage of time an energy source actually produces power relative to its maximum theoretical output, with nuclear running above **90%**, natural gas at 50–60%, wind at 25–35%, and solar at 20–25%, making it the most practical way to compare the real-world efficiency and reliability of different energy sources. While capacity factor tells us how often an energy source produces power, **levelized cost of energy, or LCOE**, tells us how much that power actually costs, making it the primary metric used by investors, utilities, and policymakers to compare the economic viability of different technologies. LCOE is calculated by dividing the present value of all costs incurred over a power plant's lifetime, including capital expenditures, fuel, maintenance, and decommissioning costs, by the present value of all electricity generated over that same period.



Source: Lazard Levelized Cost of Energy Report, 2025.

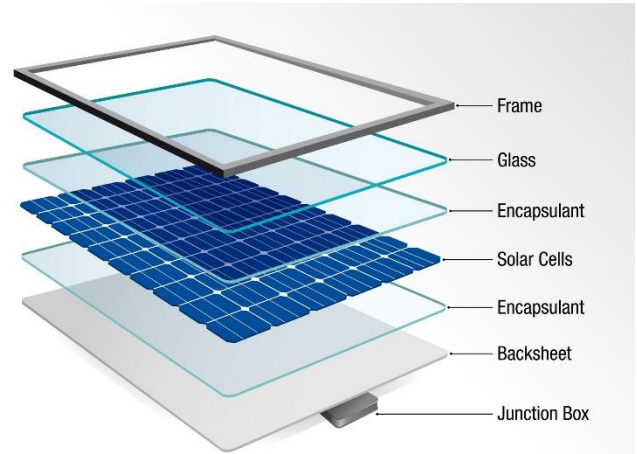
On a pure LCOE basis, onshore wind and utility-scale solar are among the cheapest ways to generate electricity today, with low-end costs of \$37 and \$38 per MWh, respectively, which at first glance makes the case for renewables appear compelling. However, when storage costs are taken into account, costs jump materially, with solar plus storage reaching \$50 to \$131 per MWh and wind plus storage reaching \$44 to \$123 per MWh, illustrating that the true cost of making renewables dispatchable and reliable is significantly higher than the headline figures suggest. Gas combined cycle is not only one of the most cost-effective energy generation sources at \$48 to \$109 per MWh, but it runs at a 50–60% capacity factor and produces power on demand at any hour of the day, making it far more reliable. Nuclear, despite its high upfront capital costs that push LCOE to \$141 to \$220 per MWh for new builds, runs above 90% capacity factor continuously and produces zero emissions, which is why many analysts argue it remains undervalued as a baseload generation source.

In the pages below, the primary renewable energy sources will be covered more in depth.

Solar

Overview

Solar energy converts sunlight into electricity through **photovoltaic (PV) panels**, which generate current by displacing electrons within silicon layers that then travel through built-in wiring. The technology is used in three main sectors: **utility-scale farms, rooftop installations, and community solar projects**. The economics of solar are heavily geography-dependent, as the Earth's tilt means solar intensity varies significantly by latitude and season. Within the United States, the Southwest commands the strongest solar resource, with the desert regions of California, Arizona, and New Mexico receiving the highest levels year-round. Globally, China has emerged as the dominant force in solar development, controlling the overwhelming majority of PV manufacturing capacity across polysilicon, wafers, cells, and modules, while also leading the world in installed capacity.



Regulatory Environment

The **Inflation Reduction Act** of 2022 was the most substantial piece of solar legislation in U.S. history up to that point, dramatically expanding federal tax credits for commercial projects and homeowners. Projects meeting certain requirements, such as using a minimum amount of domestically manufactured components or being in predominantly coal-burning regions and high-unemployment fossil fuel areas, qualified for additional credits. The result was an immediate supply chain response, with dozens of new U.S. solar manufacturing facilities announced in the years following.

The **One Big Beautiful Bill Act**, signed July 4, 2025, took much of that back. Federal incentives for residential solar were eliminated entirely. The administration framed the rollback as a necessary correction, arguing that subsidies had distorted energy markets, crowded out more reliable power sources, and left the U.S. supply chain dangerously exposed to foreign adversaries, primarily China.

Wind

Overview

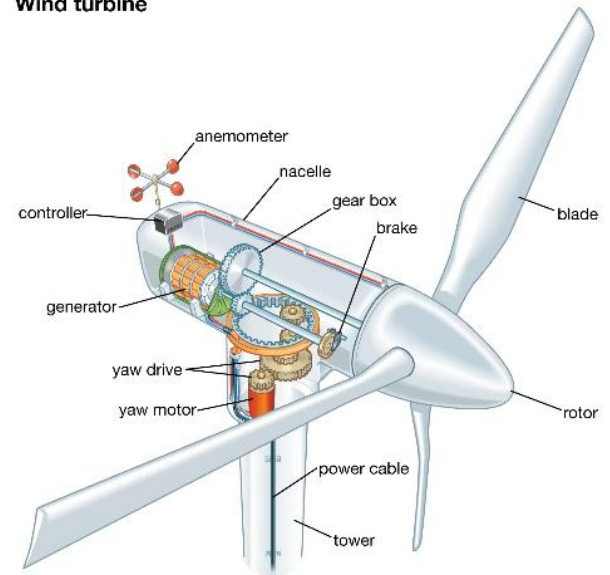
Wind energy generates electricity by using the kinetic energy of moving air to spin the blades of a turbine, which drives a generator to produce electricity. The size and height of a turbine directly determine how much energy it can capture, as wind speeds increase significantly with altitude, which is why modern turbines have grown substantially over the past few decades. Key components include the blades, which capture wind energy; the nacelle, which sits atop the tower and houses the gearbox and generator; and the tower itself, which elevates the system to where wind resources are strongest.

Turbine types are split into two distinct categories: **onshore and offshore**. Onshore wind is the more mature of the two, characterized by relatively low development costs, rapid deployment timelines, and strong placement across the Midwest and Great Plains. Texas alone accounts for a disproportionate share of national capacity because of substantial infrastructure investment that has built out the transmission lines necessary to move power from remote areas to population centers. Offshore wind operates in an entirely different cost and complexity bracket, requiring complex foundations, specialized installation vessels, and subsea transmission cables, all of which push development costs substantially higher than onshore. The benefit, however, is access to stronger and more consistent wind, as well as proximity to dense coastal load centers that onshore projects cannot easily serve.

Regulatory Environment

The Inflation Reduction Act of 2022 was the most significant piece of wind energy legislation in decades, expanding federal tax credits through 2032, and for the first time allowing developers to transfer credits to third-party investors, broadening the pool of capital available to finance new projects. The One Big Beautiful Bill Act curtailed much of that, accelerating the phase-out of wind tax credits and imposing the same foreign entity restrictions applied to solar, adding new supply chain burdens on the industry.

Wind turbine



© Encyclopædia Britannica, Inc.

Nuclear

Overview

Nuclear energy is generated through nuclear **fission**, the process of splitting a heavy atom, typically **Uranium-235**, by firing a neutron at it, causing it to break into smaller atoms while releasing enormous heat energy and additional neutrons that trigger further splits, creating a self-sustaining chain reaction. The scale of energy released is what makes nuclear unique: **a single kilogram of uranium fuel contains as much energy as approximately 3,000 tons of coal**, which is the foundational proposition of nuclear power and the reason it commands serious bipartisan support and extreme attention from energy investors.



Uranium mining is concentrated in a handful of countries, with **Kazakhstan** alone accounting for roughly 45% of global production, followed by Canada and Australia. Once mined, it is turned into **yellowcake**, a concentrated uranium powder, before being converted into a gas and fed through a series of centrifuges that spin at high speed to raise the concentration of U-235 from its natural 0.7% to the 3.5–20% required for commercial reactors. That

enriched material is then converted into a ceramic powder, pressed into small pellets roughly the size of a fingertip, loaded into 13-foot zirconium alloy tubes, and then loaded into the reactor core. The reactor's job is to control that chain reaction and harvest the heat it produces. A moderator, typically water, slows neutrons to the speed needed to sustain fission. The heat generated boils water into steam, which spins a turbine connected to a generator, producing electricity, the same basic process as a coal plant, but with fission replacing combustion as the heat source.

History and Failures

Following the Atomic Energy Act of 1954, nuclear power plants rapidly expanded across the United States and the Soviet Union throughout the Cold War, with both superpowers racing to demonstrate both military and civilian nuclear power. **Three Mile Island** in 1979 was the first major crack in public confidence, where a minor cooling malfunction cascaded through instrumentation failures and operator errors into a partial core meltdown, dropping public support for nuclear from 69% to 46% virtually overnight. **Chernobyl** in 1986 was more devastating, where a fundamentally flawed Soviet reactor design operated by a crew bypassing safety procedures resulted in two explosions, 200,000 people displaced, and a radioactive cloud that spread across the Northern Hemisphere. **Fukushima** in 2011 delivered the final blow, when a magnitude 9.0 earthquake and resulting tsunami overwhelmed a Japanese plant's backup systems, triggering reactor meltdowns that forced the evacuation of 150,000 people and caused several countries, most notably Germany, to abandon

nuclear energy entirely. Together, these three accidents created a lasting public perception of nuclear as inherently dangerous, suppressing investment in the industry until the early 2000s.

The Nuclear Advantage and New Developments

Nuclear's core economic advantage, a 92% capacity factor and carbon-free output, makes it uniquely compelling as a baseload power source, but that advantage has historically been undermined by staggering capital costs and construction timelines. At an average of \$8 billion per unit and 7.5 years to build, figures that Vogtle's \$35 billion final cost and seven-year delay demonstrated can go significantly higher, new nuclear has been extraordinarily difficult to finance without government support. **Small Modular Reactors (SMRs)** are the industry's proposed solution, promising factory-manufactured standardized modules that drive down costs through repetition rather than bespoke construction, but no SMR has been built at commercial scale, and even the most optimistic timelines place the first units in the mid-2030s.

Regulation and Key Players

The regulatory environment is finally shifting in nuclear's favor. The bipartisan ADVANCE Act of 2024 streamlined **Nuclear Regulatory Commission (NRC)** licensing, made it easier and faster to approve new reactor designs, and extended the Price-Anderson Act's liability coverage through 2065, a provision that caps operator liability in the event of an accident and makes projects insurable. On the operator side, Constellation Energy is the dominant U.S. nuclear equity with the largest fleet operator in the country, while Vistra and PSEG carry significant nuclear exposure within broader utility structures. In the SMR and advanced reactor space, TerraPower (backed by Bill Gates) is developing the Sodium sodium-cooled fast reactor with DOE funding, X-energy has Amazon as a customer for its Xe-100 pebble bed design, and Kairos Power has Google contracted for a fleet of SMRs targeting 2030. On the fuel side, Cameco is the dominant Western uranium miner, and Centrus Energy has emerged as the primary domestic enrichment play as the U.S. works to reduce its dependence on Russian supply chains.

Battery Storage

Overview

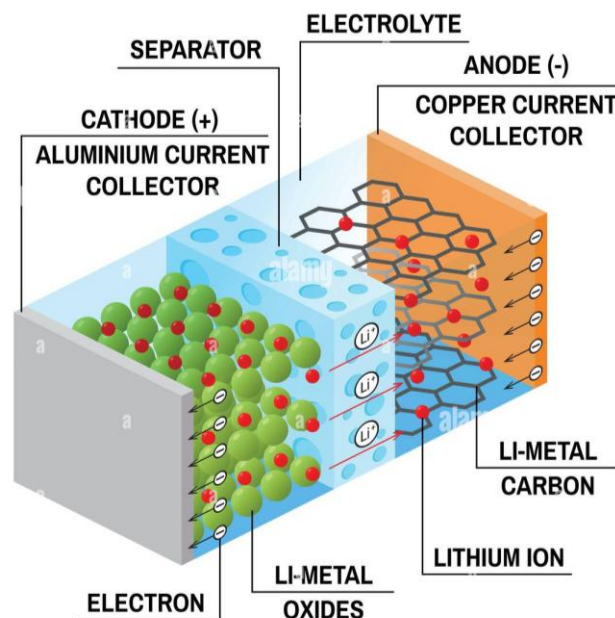
A battery is a device that stores energy in chemical form and converts it into electricity on demand. The batteries most relevant to this primer are **lithium-ion (Li-ion)** batteries: the same technology in a smartphone, an EV, and a grid storage installation, just at vastly different scales. The global Li-ion market exceeded \$150 billion in 2025. A single battery cell produces only a few volts, so to power an EV, thousands of cells are grouped into modules, which are then assembled into a pack with a Battery Management System (BMS) that monitors temperature, voltage, and charge state.

Why Lithium-ion?

Lithium is the lightest metal on the periodic table and holds more energy per unit of weight than any other metal, making it uniquely suited for applications like EVs and grid storage where size and weight constraints are critical. Unlike older battery chemistries such as lead-acid or nickel-metal hydride, lithium-ion delivers significantly higher energy density and a longer useful life. The two Li-ion chemistries that matter most are Nickel Manganese Cobalt (**NMC**) and **Lithium Iron Phosphate (LFP)**. NMC is used in long-range EVs, whereas LFP is a lower-cost, long-cycle-life battery used for grid storage and standard-range EVs. By 2035, NMC is projected to make up ~59% of the Li-ion market and LFP ~38%.

Four Components of a Lithium-ion Battery

1. **Cathode (Positive Electrode):** The cathode is the source of lithium ions and the primary driver of a battery's energy storage capacity. It is typically made from a metal oxide compound and is the most expensive part of the cell, accounting for roughly 40–50% of cell material cost.
2. **Anode:** The anode is where lithium ions are stored when the battery is in use (discharging). Almost all commercial anodes today are made from **graphite**, which is why graphite is a critical mineral in the battery supply chain. When you



charge a battery, lithium ions travel from the cathode to the anode; when you discharge it (e.g., driving your EV), they travel back.

3. **Electrolyte:** The electrolyte is the medium, typically a liquid salt solution, through which lithium ions travel between the cathode and anode. It conducts ions but not electrons; the electrons must flow through the external circuit (the car's motor, the power grid), which is what produces usable electricity.
4. **Separator:** A thin membrane, typically 10–25 microns thick (thinner than a human hair), that physically sits between the cathode and anode. It prevents the two electrodes from touching, which would cause a short circuit.

Battery Value Chain

1. **Upstream:** The upstream stage covers mining and initial refining of the raw materials that go into a battery: lithium, nickel, cobalt, manganese, and graphite. China controls roughly 67% of global lithium refining capacity and 93% of graphite anode production. The U.S. and Europe each hold less than 10% of global cathode precursor and anode graphite capacity.
2. **Midstream & Manufacturing:** Midstream transforms the raw minerals into the actual battery. The process has two sub-stages. First, **chemical processing** converts refined minerals into battery-grade cathode active material (CAM), precursor CAM (pCAM), electrolyte salts, and separator film. Second, **cell manufacturing** builds the cells and assembles them into modules and packs with a battery management system, thermal controls, and structural casing.
3. **Downstream:** Downstream encompasses the integration of batteries into their final applications by automakers, utilities, and technology companies. The primary end markets are **electric vehicles** (~85% of battery demand), **battery energy storage systems or BESS** (~12%), and **consumer electronics, defense systems, and AI data centers** (~3%).

Regulatory Environment

The dominant U.S. policy framework through 2024 was the Inflation Reduction Act (IRA), which combined manufacturing incentives, demand incentives, and supply chain localization requirements to build a domestic battery industry. That framework was materially restructured in July 2025 with the **One Big Beautiful Bill Act (OBBBA)**. The OBBBA terminated all major EV purchase credits: the \$7,500 new vehicle credit (30D), \$4,000 used vehicle credit (25E), and commercial fleet credit

(45W), effective September 30, 2025. The impact was immediate: U.S. EV sales fell ~36% between Q4 2024 and Q4 2025.

Global Lithium-ion Macro

Supply: China manufactures over 80% of all batteries sold globally and controls 67% of lithium refining and 93% of graphite anode production. The top two cell manufacturers, CATL and BYD, are both Chinese, and their combined scale has proven difficult to displace. The U.S. has responded with a combination of steep tariffs on Chinese imports and the IRA's Section 45X manufacturing credit, which have helped seed over 180 battery facilities across 38 states, but structural gaps across the supply chains remain.

Demand: Total Li-ion deployment reached ~1,600 GWh in 2025, six times the 2020 level, with EVs accounting for roughly 85.2% of volume and grid-scale storage accelerating sharply. Many analysts predict this number to double by 2030, and even the most conservative scenarios still imply over 50% growth from current levels.

The AI Future of Batteries

The rapid expansion of AI infrastructure is creating a new demand for battery storage. Data centers powering large language models and AI workloads are extraordinarily energy-intensive, and the grid infrastructure in most markets is not being built fast enough to keep pace, making on-site and grid-connected battery storage a necessity. AI data centers operate with zero tolerance for power interruption; even a millisecond outage can corrupt workloads worth millions of dollars, making large-scale battery systems the buffer.

Private Investments

Overview

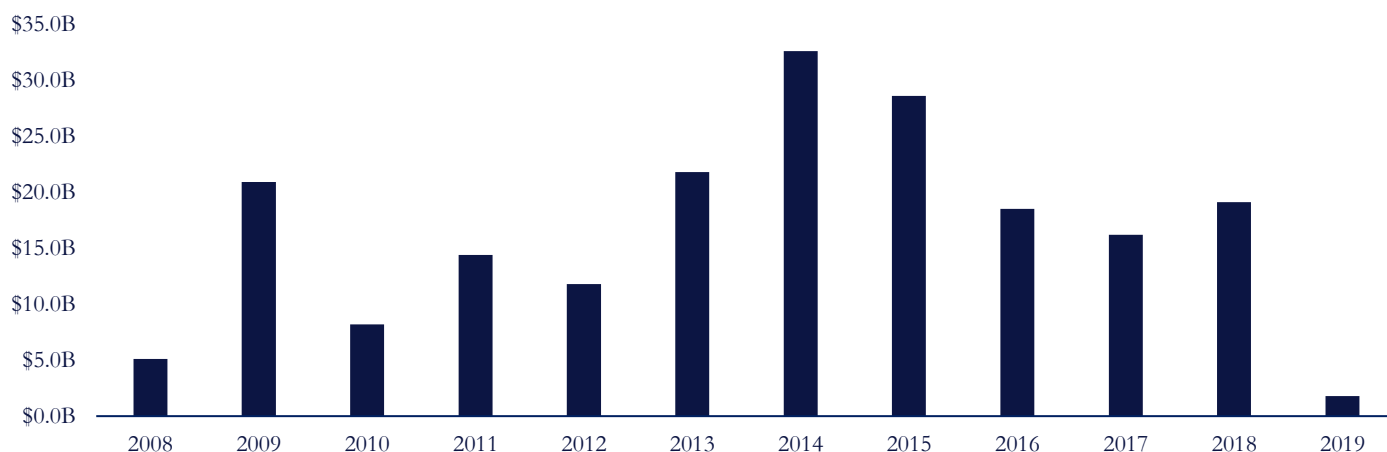
Private energy investment lets individuals and institutions deploy capital selectively across businesses ranging from upstream E&P to larger infrastructure and renewables players, whether through energy-focused PE firms, VC funds, individual backings, or take-privates.

Private capital carries more weight in energy than in most sectors, largely because the work is capital-intensive and long-dated: drilling programs, midstream buildouts, and power projects require large upfront outlays and take years to generate returns. Over the past decade, public markets have grown reluctant to fund that profile and have pushed operators to prioritize capital discipline, free cash flow, and shareholder returns over production growth, which pulled back the pool of public capital available for new development. Private sponsors, with longer time horizons and no quarterly earnings pressure, have stepped in to fill that gap.

Sponsors have also become the natural buyer for assets that large-cap operators divest as they **high-grade** their portfolios. High-grading refers to operators concentrating capital on their best acreage and core basins and selling non-core or lower-return assets to fund that focus. Those divested assets, often still productive but no longer strategic for a major, are well suited to a sponsor that can operate them under a dedicated, return-driven mandate.

That dynamic makes private equity a primary source of the industry's deal flow. A sponsor typically capitalizes a company, funds its buildout, and then sells it within a roughly three-to-seven-year hold. That exit, whether a sale to a strategic buyer or another sponsor, becomes a sell-side mandate for an investment bank, which advises on and runs the transaction. Because sponsors are structurally built to buy and then sell, they generate a recurring pipeline of these mandates, driving much of energy IB activity.

Oil & Gas PE Fundraising



Source: Business Insider, 2025.

History

Energy private equity saw significant investments during the Shale Revolution that took hold in the U.S. during the early 2000s. Recently, pressure from LPs to invest in more clean energy has dampened investment in traditional energy. Despite this, many large energy funds still thrive in the space, continuing the model of backing small drillers or investing in non-operated oil and gas assets.

Companies

The energy PE space includes both mega funds with energy groups and independent, energy-focused funds. Dominant energy-focused players include **Quantum Capital Group, EnCap Investments, NGP, Carnelian, Kayne Anderson, Pearl Energy Investments, First Reserve, and Tailwater Capital**. These companies traditionally operate by investing in portfolio companies, or PortCos, which are usually smaller oil and gas companies. Many current public companies started as PE-backed drillers, including large caps like Diamondback and Antero, as well as smaller publics like Summit Midstream. Less commonly, public energy companies are taken private. One of the most notable of these was the take-private of Continental Resources (formerly NYSE: CLR) by Harold Hamm in November 2022. The transaction involved over \$4 billion of cash consideration for shareholders, forming the largest private E&P company in the U.S.

Structure

The PE company (often referred to as the sponsor) will source capital from **limited partners (LPs)**. These LPs usually consist of school endowments, government pension plans, and wealthy individual investors. The PE sponsor, or **general partner (GP)**, will then fund the PortCo, allowing the company to operate. In exchange for facilitating the funding of the PortCo, the PE sponsor takes a **2% fee per year**, plus an additional **20%** of excess returns beyond an $\sim 8\%$ IRR hurdle.

Alongside their fund commitments, LPs are sometimes offered the chance to **co-invest**, meaning they put additional capital directly into a specific deal rather than through the fund. Co-investments are typically offered when a deal is larger than the fund wants to hold on its own, and they usually carry reduced or no fees, making them attractive to LPs seeking more exposure to a particular company at a lower cost. This lets the sponsor pursue bigger transactions without over-concentrating the fund, while giving participating LPs a larger stake in deals they find compelling.

When a PE fund ends its life, companies exit their positions through **IPOs, strategic exits, or other PE companies**. For asset-level funds, these exits usually involve selling the assets to other private or public companies. Private investments tend to be riskier than public equities, but offer the opportunity for higher returns, often in excess of 20%.

Energy Finance

Overview

Houston is often referred to as the “energy capital of the world,” and hundreds of energy companies have their headquarters there. For this reason, many **investment banks, hedge funds, and private equity firms** have energy-focused roles in Houston. This primer will analyze the investment banking sector in depth.

Investment banks advise companies on a few core activities: **capital raising, mergers and acquisitions (M&A), and financial restructuring**. Capital raising is the process of securing funds for a company to grow, and it comes in two forms. The first is **equity capital markets (ECM)**, where the bank sells stock to investors through offerings such as an **initial public offering (IPO)**. The second is **debt capital markets (DCM)**, where the bank helps the company borrow by issuing bonds, arranging loans, or lending from its own balance sheet. In M&A, when a company seeks to acquire a competitor or sell itself, the bank advises on the transaction and helps execute it by valuing the business and negotiating with the buyers or targets involved. Restructuring applies when a company is burdened by excessive debt or financial distress; here the bank advises on reorganizing its obligations, often negotiating with creditors to avoid or work through bankruptcy. It is important to note that not all investment banks advise on every one of these activities. The banks themselves are generally grouped into two categories: **bulge bracket** banks and **independent or boutique** firms.

Bulge bracket banks, such as **J.P. Morgan, Goldman Sachs, and Citi**, are large, full-service institutions. They advise on transactions, raise capital for clients, and lend their own capital to help finance deals, supported by substantial balance sheets. Independent banks, such as **Moelis, Evercore, Lazard, and PJT**, focus primarily on advisory services but not lending. They don’t lend or commit capital because they’re built as pure advisory firms that earn fees for advice alone, which keeps them free of the conflicts of interest, regulatory burden, and capital requirements that come with lending. A conflict could arise, for example, if a bank that both advises a client and lends to it steered that client toward a debt-heavy acquisition, since the bank would collect an advisory fee for recommending the deal and then earn interest on the loan it provides to fund it, even if that much debt was not in the client’s best interest.

In the energy industry, transactions take two forms. A company may acquire or sell an entire business, known as a **corporate transaction**, or it may acquire or sell specific assets, such as a package of producing wells or undeveloped acreage, without the corporate entity changing hands. The latter is referred to as **A&D**, short for **acquisitions and divestitures**. Because valuing oil and gas assets requires substantial engineering and geological analysis to estimate the reserves held in the ground, A&D mandates typically go to specialized energy banks such as **RBC Richardson Barr** and **Jefferies** rather than to generalist M&A teams.

Investment Banking Roles and Job Description

An investment banking analyst is the most junior member of a deal team, typically hired straight out of college into a two- to three-year program. Analysts sit at the bottom of a hierarchy that runs through associate, vice president, director, and managing director, and perform the bulk of the technical work behind a transaction.

The day-to-day work centers on financial analysis and client materials. Analysts build financial models to value companies and evaluate deals, prepare the pitch books that senior bankers use to win and advise on business, and conduct research. The work is detail-intensive, and precision matters greatly, since a single error in a model or presentation can undermine the team's accuracy and credibility.

The hours are demanding. Analysts regularly work 70 to 100 hours per week, juggling multiple projects and supporting senior bankers under constant time pressure. The schedule is unpredictable because client demands and last-minute requests can arise at any time.

Energy Investment Banking Interviews

While energy groups at various investment banks follow similar recruiting practices and ask many of the same questions as their peers in other cities and industries, it is important to understand the similarities and differences.

Most banks in Houston will have **first-round/screening interviews** where one or two analysts will ask various technical and behavioral questions to determine which candidates will go to the group's superday. Superdays last multiple hours and consist of applicants rotating through several interviews back-to-back. Banks can vary in the difficulty of technical questions they ask, but candidates should expect a mix of traditional questions, along with industry-specific questions. Some energy interview-specific questions include:

- **Why energy?** This question is gauging why a candidate is interviewing with energy coverage groups in Houston.
- **Why Houston?** Like the question above, this tests to see if candidates are willing and enthusiastic about moving to Houston upon graduation. Responses can include family connections to Houston or Houston's importance within the energy sector.
- **Where do you see the price of [commodity] going?** This question could be asked with any commodity associated with the energy sector, but it is generally focused on crude oil. Candidates should display a knowledge of current events and the factors that affect various commodity prices.
- **What are your thoughts on the energy transition?** Candidates should display an understanding of how the transition is shaping the industry. Remember that the problems and solutions presented in general media coverage are often overblown, and that most analysts do not believe that the transition will happen as quickly as politicians and activists hope.

- **Pitch me a stock.** This is a common question at many banks, and candidates need to have an energy sector equity in mind.
- **Which vertical would you invest money in right now?** Candidates should display a knowledge of cycle economics, current events, and how both affect the verticals. Midstream is always a safe choice, but it will not be memorable.
- **Describe the verticals.** Interviewers are looking for knowledge about each vertical and how they operate.
- **How would you value an Upstream project?** Candidates can say that comparable company analysis, precedent transactions, and dev models/NAVs would all be appropriate valuation techniques.

Additional Questions:

- How did the COVID-19 pandemic affect the O&G industry?
- What type of crude is WTI? Brent? Which one trades higher? Why?
- Where is WTI priced, and in what units?
- Where is U.S. natural gas priced, and in what units?
- What is the difference between contango and backwardation?
- How many gallons are in a barrel of oil?
- How many cubic feet of natural gas are in a barrel of oil equivalent?
- What are the four verticals, and rank them from most risky to least?
- List 3–5 companies within each vertical.
- What is the difference between an MLP and C-Corp?
- What is beta?
- Tell me about a recent deal.
- At a high level, walk through the process of drilling and fracking a well.
- What is the difference between successful efforts and full cost accounting?
- What are the different types of reserves? (3Ps)
- List 3–5 basins or plays in the U.S.
- Walk me through a NAV model.
- Why do we use NAV models instead of a DCF for upstream valuation?
- Why do we use EV/EBITDAX in upstream valuation?
- What is the difference between processing and fractionation?
- What is the crack spread?

These are only a few of the many questions that might come up in an energy investment banking interview, but they are some of the most common. Regardless, it is important to understand how the sector works and the current events that are affecting it. It is wise to read up on the news and **check**

the price of WTI, Brent, and natural gas before every interview. To stay up to date on current energy news, some helpful sources include the EIA, IEA, FERC, SEC filings, company investor presentations, the WSJ, Hart Energy, Enverus, CME/ICE, and the RBC Richardson Barr website.

Key Terms:

A&D (Acquisitions & Divestitures): Buying and selling specific oil and gas assets (wells, acreage) rather than entire companies

API Gravity: A reverse measure of crude density; higher API means lighter crude (31.1° or above is light, below 10° is heavy)

ARO (Asset Retirement Obligation): Balance sheet liability for the future cost of plugging and abandoning a well once it stops producing

Associated Gas: Natural gas produced as an unavoidable byproduct of oil-directed drilling

Backwardation: Spot price above the futures curve; the market expects lower prices in the future

Baseload: Generation that runs around the clock to meet minimum demand (e.g., nuclear)

Behind-the-Meter: On-site power generation (often gas-fired) that serves a facility directly and bypasses the grid

BESS (Battery Energy Storage System): Grid-scale battery installations; roughly 12% of lithium-ion demand

Beta: A measure of systematic risk – how volatile a stock is relative to the broader market

BOE (Barrel of Oil Equivalent): Converts gas into oil terms; 1 barrel of oil = 6 Mcf of natural gas

BOP (Blowout Preventer): Stack of valves at the wellhead that seals the well to prevent an uncontrolled release (blowout)

Brent: The international crude benchmark, tied to four North Sea streams (BFOE) and settled financially

Bulge Bracket: Large full-service banks (J.P. Morgan, Goldman Sachs, Citi) that both advise and lend

Capacity Factor: The percentage of time a power source actually produces versus its theoretical maximum (nuclear 90%+, solar 20–25%)

Contango: Futures price above spot; the market expects higher prices in the future

Costless Collar: Hedge pairing a purchased put (price floor) with a sold call (price ceiling) so the premiums offset and there is no upfront cost

Crack Spread: A quick proxy for refining margins, most commonly 3:2:1 – three barrels of crude yielding two of gasoline and one of distillate

DD&A (Depletion, Depreciation & Amortization): Expense recognizing that each barrel produced permanently reduces the value of the reserve asset in the ground

Differential: The gap between a benchmark price and the price actually received at a delivery point

Dry Hole: An exploratory well that fails to find commercially viable hydrocarbons

DUC (Drilled but Uncompleted Well): A drilled well awaiting fracking, held as inventory until prices, crews, or takeaway capacity improve

E&P (Exploration & Production): Upstream companies that find and produce hydrocarbons

EBITDAX: EBITDA plus exploration expense; the EV/EBITDAX multiple normalizes the difference between full cost and successful efforts accounting

ECM / DCM: Equity and Debt Capital Markets – raising capital through stock offerings or through bond and loan issuance

EOR (Enhanced Oil Recovery): Injecting gas, water, chemicals, or steam into a mature reservoir to recover oil beyond what natural pressure allows

EPC (Engineering, Procurement & Construction): Contract model where a single contractor delivers a large project, often at a fixed price, shifting execution risk off the operator

ERCOT: The Texas grid operator; isolated from the other interconnections, which limits federal oversight but prevents importing power in emergencies

FERC (Federal Energy Regulatory Commission): Federal regulator of interstate pipelines and transmission

FLNG / FSRU: Floating vessels that liquefy or regasify LNG offshore

Force Majeure Clause: Suspends lease obligations during events beyond either party's control, preserving the operator's leasehold interest

Fracking (Hydraulic Fracturing): Injecting high-pressure water, sand, and chemicals to crack tight rock so hydrocarbons can flow to the wellbore

Fractionation: Separating mixed NGLs into individual products (ethane, propane, butane) based on their different boiling points

Habendum Clause: Splits a lease into a fixed primary term and a secondary term that continues as long as the well produces

Henry Hub: The U.S. natural gas benchmark, priced in \$/MMBtu at Erath, Louisiana

IDR (Incentive Distribution Right): Entitles an MLP's general partner to a growing share of incremental cash distributions as payout thresholds are hit

IP (Initial Production): A well's starting production rate – the anchor point of the type curve

IPP (Independent Power Producer): Owns power plants and sells into wholesale markets, fully exposed to power prices, unlike regulated utilities

IRA (Inflation Reduction Act): 2022 law that dramatically expanded federal tax credits for solar, wind, and batteries; largely rolled back by the OBBBA

ISO / RTO: Independent grid operators (PJM, MISO, CAISO, ERCOT) that manage electricity flow and run wholesale power markets without owning generation

Landman: The link between an operator and mineral owners – researches title, negotiates leases, and feeds the division order that pays each owner

LCOE (Levelized Cost of Energy): Lifetime plant costs divided by lifetime electricity generated; the standard metric for comparing generation technologies

LFP / NMC: The two dominant lithium-ion chemistries – LFP for grid storage and standard-range EVs, NMC for long-range EVs

LMP (Locational Marginal Pricing): Wholesale power price at a grid point – marginal generation cost plus congestion plus line losses

LNG (Liquefied Natural Gas): Gas cooled to around -162°C, shrinking its volume 600x for seaborne transport to markets pipelines cannot reach

LOE (Lease Operating Expense): The recurring cost of operating a producing well

MLP (Master Limited Partnership): Publicly traded partnership with pass-through taxation, common in midstream; investors receive K-1s and tax-exempt institutions can face UBTI

MMBtu: Million British thermal units – the standard pricing unit for U.S. natural gas

MVC (Minimum Volume Commitment): A shipper's commitment to move minimum volumes on a midstream system or pay for the shortfall

NAV (Net Asset Value) Model: Upstream intrinsic valuation that sums the discounted cash flows of producing wells and future development locations

NCI (Nelson Complexity Index): Measures refinery sophistication; higher-NCI refineries can turn cheaper, heavier crudes into more valuable products

NGLs (Natural Gas Liquids): Ethane, propane, butane, isobutane, and natural gasoline – separated from wet gas and priced individually at Mont Belvieu

NOC (National Oil Company): State-owned producer (e.g., Saudi Aramco) whose objectives extend beyond maximizing shareholder value

NRI (Net Revenue Interest): The share of production revenue kept after royalties are paid ($1 - \text{royalty \%}$)

OBBBA (One Big Beautiful Bill Act): July 2025 law rolling back IRA incentives – eliminated residential solar and EV credits and accelerated the phase-out of wind and solar credits

OFS (Oil Field Services): Companies providing seismic, drilling, completion, and stimulation services to E&Ps; the most cyclical, highest-beta vertical

OPEC / OPEC+: The Organization of the Petroleum Exporting Countries – a cartel coordinating member production quotas to influence global crude prices; OPEC+ adds allies such as Russia and Kazakhstan

1P / 2P / 3P Reserves: Proved (90% probability of commercial recovery), probable (50%), and possible (10%) reserve categories

PDP / PUD: Proved Developed Producing wells (online and generating cash flow) versus Proved Undeveloped locations (future drilling inventory)

Petrodollar: The 1974 U.S.–Saudi arrangement pricing oil exclusively in dollars and recycling the surpluses into U.S. Treasuries

Pooling: Combining acreage from multiple landowners into a single production unit held by one well

Produced Water: Saltwater that comes up with production and must be gathered, disposed of, or recycled; volumes grow as shale wells age

Proppant: The sand in frac fluid that props fractures open so hydrocarbons can flow to the wellbore

Pugh Clause: Releases acreage not included in a producing unit, preventing an operator from holding an entire tract with a single well

PV-10: A 10% discount rate – the industry standard for valuing PDP reserves

Rate Base: A regulated utility's invested capital, on which it earns its allowed return (typically 9–11% ROE); growing rate base is how utilities grow earnings

RIN (Renewable Identification Number): Tradeable credit proving a gallon of biofuel was blended; used for Renewable Fuel Standard compliance

SAGD (Steam-Assisted Gravity Drainage): In-situ oil sands method using paired horizontal wells to inject steam and drain the heated bitumen

Seven Sisters: The handful of majors (predecessors of BP, Chevron, ExxonMobil, Shell) that controlled global oil markets before OPEC's rise

Shut-In Royalty Clause: Lets an operator preserve a lease by paying a fee while a capable well is temporarily offline

SMR (Small Modular Reactor): Factory-built nuclear design intended to cut costs through standardization

Take-or-Pay: Contract requiring payment for reserved pipeline capacity whether or not it is used

Type Curve (Decline Curve): Projection of a well's output from initial production through its decline; the foundation of the single-well model

Waha Hub: The West Texas gas pricing point; constrained takeaway capacity means it often trades at a steep discount to Henry Hub – at times negative

WI (Working Interest): A participant's share of a well's costs and ownership; revenue share equals $WI \times NRI$

WTI (West Texas Intermediate): The U.S. light sweet crude benchmark, physically settled at Cushing, Oklahoma