Is the Shale Oil “Rush” Over?

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Key Points

The California Gold Rush was a time of exuberance and technological development in the mining sector and exhibits significant parallels with shale development that are worth exploring. The "easy" wins of the pioneers gave way to larger organizations with better funding and technology, squeezing out smaller players as shale development became a contest of efficiency and diminishing returns. The following supporting factors for shale are also similar to those found for the California Gold Rush:

- A well-developed financial system, diversified service industry, and supporting infrastructure.
- The hard work and tenacity of independent oil companies that continue to dominate exploration and production activities.
- The increasing returns to scale that have prevailed in the industry due to operators' ability to engage in merger and acquisition (M&A) activities and create value under adverse market conditions.
- The U.S. government's move to lift the historical ban on U.S. oil exports in late 2015.
- A relatively sympathetic public attitude toward oil and gas (O&G) developments and the fact that landowners stand to benefit financially from extraction—a condition not found in other countries.

Similar to the California Gold Rush, those firms working in shale have evolved in response to this growing level of competition through growth and consolidation. Shale-centric firms (independents) scaled quickly, as outside interests (integrated oil companies (IOCs)) increasingly bought their way in. Thus far, independent firms, including EOG Resources, Marathon Oil, and Noble Energy, still dominate exploration and production. These independents are now capitalizing on their earned technical skills and economies of scale to extend their reach overseas into the realms of IOCs and national oil companies (NOCs). However, while there ample shale resources (419 billion barrels in 40 countries around the globe) exist, without the supporting factors available in the U.S., the shale boom will be difficult to export. Notable exceptions include the Vaca Muerta Basin in Argentina and the Jafurah Basin in Saudi Arabia, which both enjoy significant government backing and an extensive O&G industry.

Unlike gold, shale oil is substitutable, and relatively more expensive to develop than are onshore reserves in the Middle East and some deepwater plays, suggesting that other lower-cost drilling options are more resilient to periods of low oil prices—as witnessed during the coronavirus disease 2019 (COVID-19) pandemic. If the degree of substitution of renewables and other sources for oil increases in the coming years, then shale is likely to suffer most due to these cost factors, intensifying its short-term nature.

For these reasons, we do not expect U.S. tight oil to replace the Organization of the Petroleum Exporting Countries (OPEC; Saudi Arabia) as a swing producer in the oil industry. While shale can be considered a swing alternative in a short-term supply crisis, its upside potential is not sufficient to meet global demand in the long term. Environmental initiatives that include bans on fracking, methane emissions, and permitting will hasten the decline of shale. While some analysts are predicting a new commodity supercycle, where high prices incentivize global shale development, policy-makers should be wary that boom towns often become ghost towns when the bust eventually arrives.

Introduction

Once believed to be economically infeasible, tight (shale[1]) oil has emerged as a critical component in the energy market. The shale boom started at the hands of a few innovative entrepreneurs such as George Mitchell, who, through relentless trials and many failures, managed to transform these “infeasible resources” into commercial resources. Favorable oil and gas (O&G) prices; good fiscal terms; access to capital; technological innovations such as seismic imaging, horizontal drilling, and hydraulic fracturing[2]; and economies of scale were the perfect combination with which to exploit these assets. This altogether allowed the U.S. to achieve a comparative advantage in light[3] oil production over, for instance, Nigeria.

As a result of the tight oil boom, U.S. oil production surpassed Russian output in 2011, and ever since, the U.S. has become the world’s largest oil producer (EIA 2019), creating a shift in the world’s energy landscape, economy, and politics. However, U.S. oil production leadership experienced significant losses during the coronavirus disease 2019 (COVID-19) crisis, showing its susceptibility to oil prices. As of year-end 2022, tight oil production represented approximately 68% of total U.S. oil production compared to less than 10% a decade ago (Figure 1).

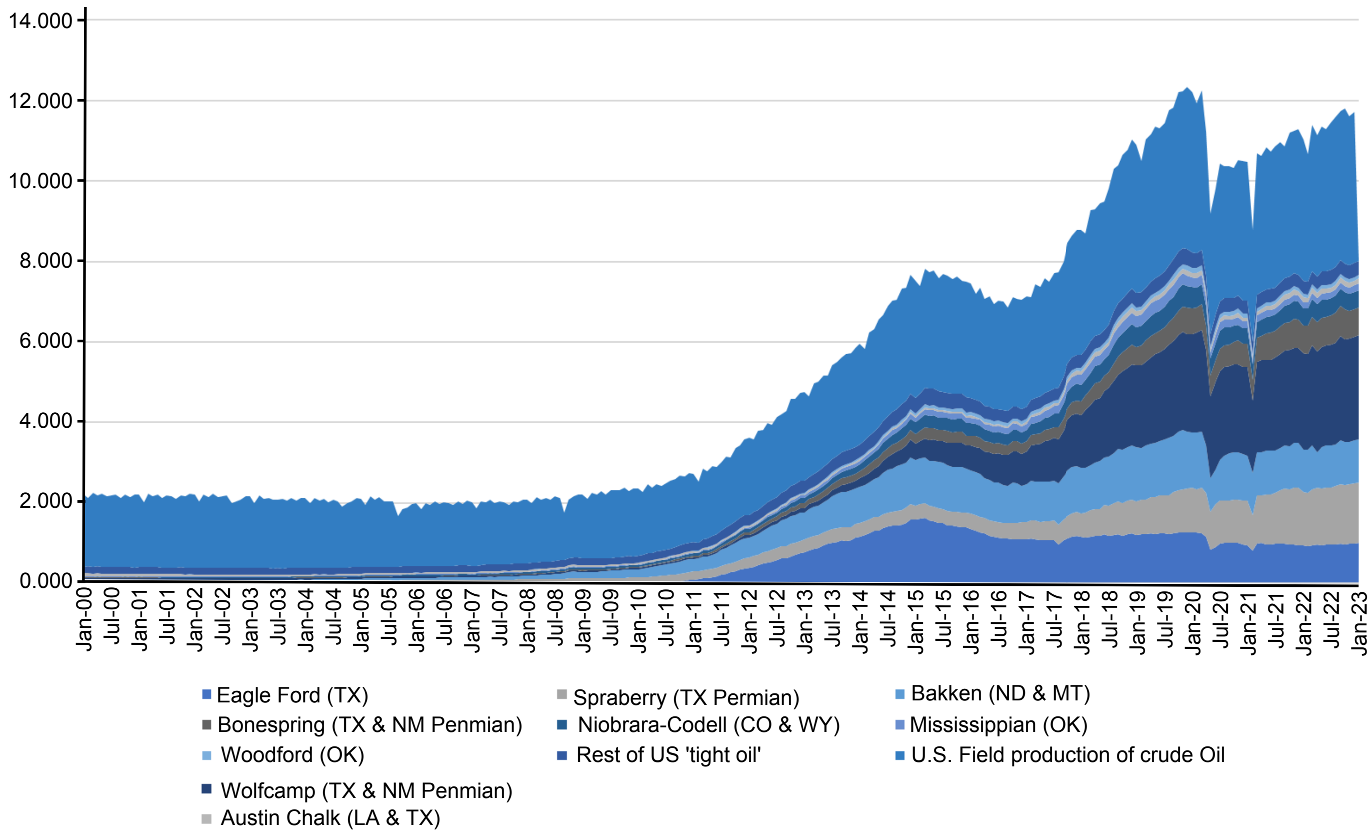
As this paper explores the tight oil industry, it replicates a partially competitive market in an industry dominated by major players. There are many striking similarities between the tight oil boom and the California Gold Rush, and this paper explores the many lessons drawn from history and reflects on the future of the U.S. tight oil industry.

This discussion paper is part of a series of studies examining the U.S. shale industry’s historical growth and sustainability and highlighting both opportunities in the shale space and challenges that may impede its growth, such as those related to technology, environmental concerns, and access to capital. The paper examines the role of tight oil in a post-COVID-19 world and shares insights about its growth in the future and how current oil and climate policies may impede its growth. The first six sections deal with the history and evolution of the U.S. shale industry. Section 1 provides a definition of shale oil illustrating the size and location of the major basins in the U.S. Considerations such as low overall productivity, steep decline rates and high capital requirements are addressed in detail. Section 2 explains the evolution of tight oil financing. Section 3 describes the dynamic innovation of the U.S. shale industry and includes a discussion of directional drilling and multiwell pad[4] development operations. The rise and fall of independent oil companies is discussed in detail in Section 4. Section 5 answers the following question: “Has technological innovation reached a threshold in the shale industry?” Finally, Section 6 examines the advent of Big Oil, or integrated oil companies (IOCs), such as U.S.-based Chevron Corporation or foreign-based British Petroleum (BP), which were latecomers to the tight oil industry.

The next part of the paper addresses the unique, contemporary characteristics of shale oil and how these can be expected to influence the future development of the industry. Section 7 examines the major features of tight oil markets including free and easy entry and exit, a standardized product, the number of buyers and sellers, market concentration and transparency. Section 8 addresses the following question: “Why has tight oil not succeeded globally outside of the U.S.?” Section 9 examines the future of tight oil in the U.S, addressing questions such as the following.

(i) "Can U.S. shale be the new swing producer? (ii) What is the breakeven price for shale? (iii) Is there a pathway to a sustainable future? Finally, Sections 10 and 11 examine the long-term future of U.S. shale including a boom-and-bust scenario analysis. The conclusions section summarizes the key findings of the paper and suggests some policy implications.

Figure 1. Historical U.S. crude oil production by shale play (MMb/d).



Source: U.S. EIA, 2023.

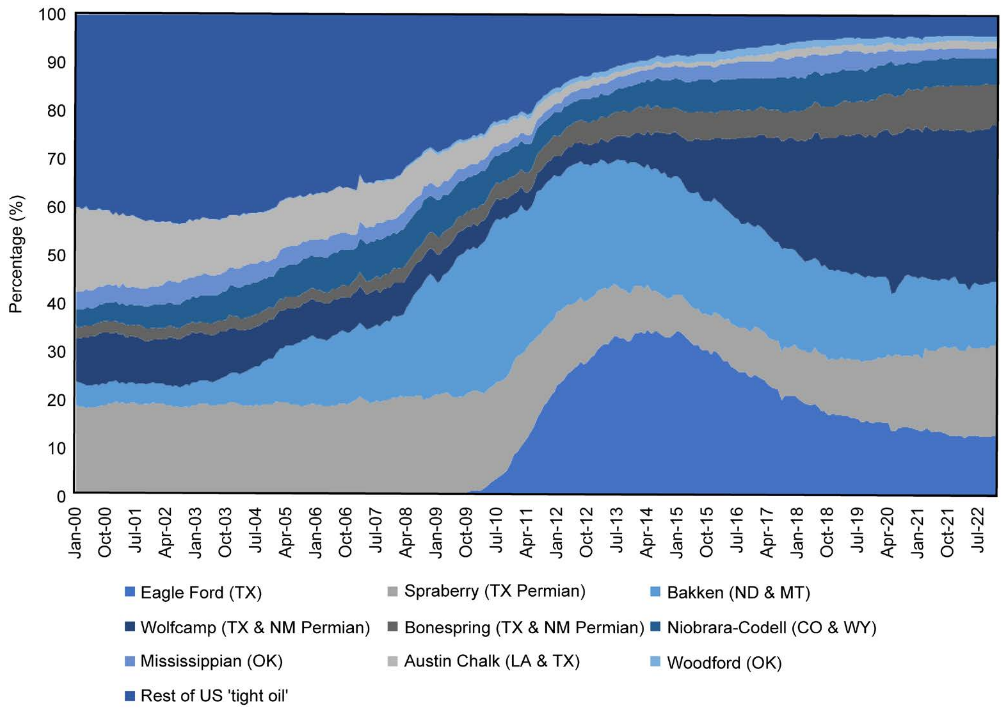
Section 1: What is Tight (Shale) Oil?

Shale is a type of sedimentary rock that forms over time with the settling of mineral and organic particles. With heat and pressure, settled organic matter can yield fossil fuels. Hydrocarbon deposits in these shale formations are known as tight oil and shale gas and are typically trapped in very tight void spaces with good porosity. These spaces, however, are poorly connected. These formations laterally and vertically contain significant O&G resources in place.

Shale deposits had been known and studied for decades but were labeled as contingent resources. Despite their sheer size, the use of shale deposits was not economically feasible due to the advanced technologies, agile business models, and relatively higher oil prices required to exploit them. Tight oil comprises high American Petroleum Institute (API) gravities in the ranges of 40 to 70 degrees, making the crude very light with qualities similar to refined gasoline. Because of these relatively high API gravities, many U.S. refineries that were accustomed to denser crude intakes shifted to accommodate the increased intake of lighter crude grades during the shale boom that began in the early 2010s.

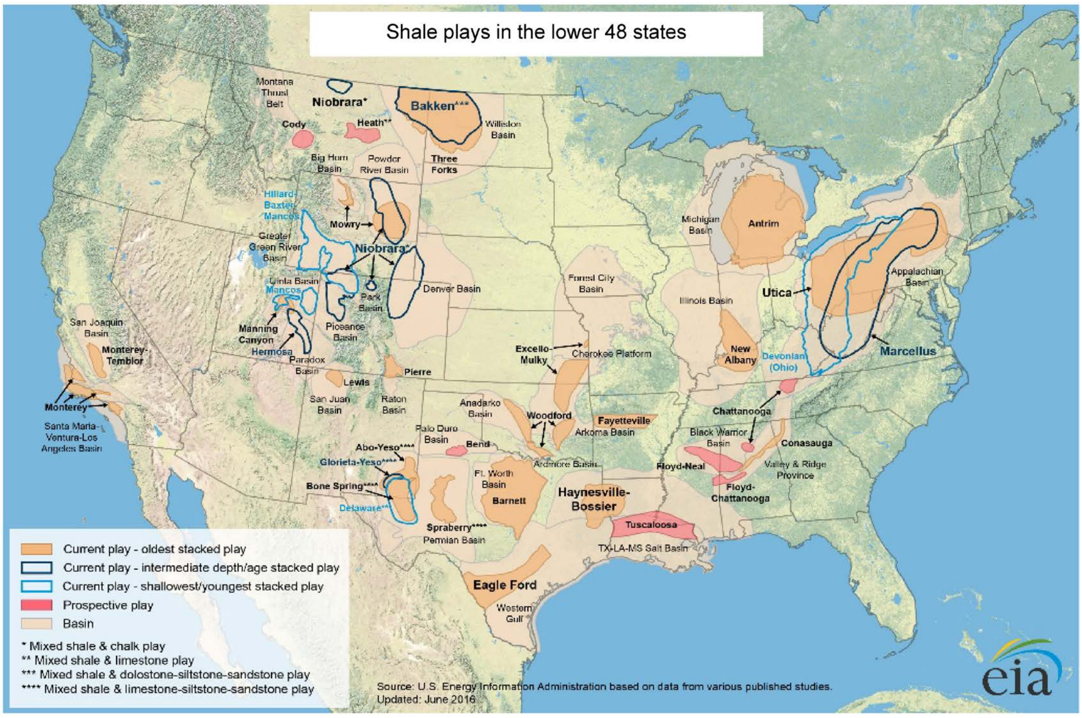
According to the EIA, it is estimated that North America had approximately 100 billion barrels of tight oil and 1,740 trillion cubic feet of shale gas in technically recoverable reserves by year-end 2015 (EIA, World Shale Resource Assessments 2015). Tight oil now accounts for over 65% of U.S. liquid oil production, as shown in Figure 1. The U.S. has approximately 137 shale formations, whereas tight oil production comes primarily from 7 major shale oil plays, as depicted in Figures 2 and 3. The U.S.'s technically recoverable resources in tight

Figure 2. U.S. tight oil production contribution per shale play.



Source: EIA, 2023.

Figure 3. U.S. shale plays.



Source: EIA, 2023.

oil formations were estimated to be 78.2 billion barrels of crude in 2015 (EIA 2015). These figures, however, might be overly optimistic, as most plays may have already peaked, some technological limitations are yet to be discussed, and the estimated ultimate recoveries have often been extrapolated from oil production in “sweet spots,” according to David Hughes in his report “Shale Reality Check” (Hughes 2021).

Most of the discussions regarding shale development and its growth in this paper focus on the Permian Basin, whose level of production has experienced explosive growth since 2014 due to the entrance of major players, as is discussed later in this paper. This basin, situated in West Texas and Southeast New Mexico, is now the largest actively producing shale basin in the U.S., with a surface area of 75 thousand square miles, approximately 22 times the size of the land above the Ghawar oilfield in Saudi Arabia.

The basin contains both shale formations and conventional accumulations. Production from conventional reservoirs began in 1920 and peaked in the late 1970s. The Permian was revitalized through significant production activities in late 2000 from its shale formations and has been in the media spotlight ever since. Much of the revitalization of the Permian is attributed to technology spillovers from the Bakken and other basins and the proximity to demand centers as well as existing infrastructure, which intrigued Big Oil companies, including ExxonMobil and Chevron, to exploit them.

Tight oil development requires innovative and cost-effective technologies such as directional drilling and hydraulic fracturing, or “fracking” for simplicity, to extract hydrocarbons, thus requiring additional, sizable capital investments. Despite these innovative technologies, tight oil wells suffer from a low degree of well productivity, high capital expenditure (CapEx), and steep declining trends. Each of these features is examined below.

1. Low Overall Well Productivity

The overall U.S. average well productivity (estimated by dividing daily production per annum by the number of active wells) was 94 barrels per day in 2016, as depicted in Figure 4. The figure illustrates average well productivity and includes the contribution of tight and conventional oil wells. Comparing this productivity with that of Organization of the Petroleum Exporting Countries (OPEC) members and the rest of the world shows that tight oil wells are no match for conventional producers in Saudi Arabia, Iraq, Iran, Nigeria, and Venezuela. – repeating the previous paragraph

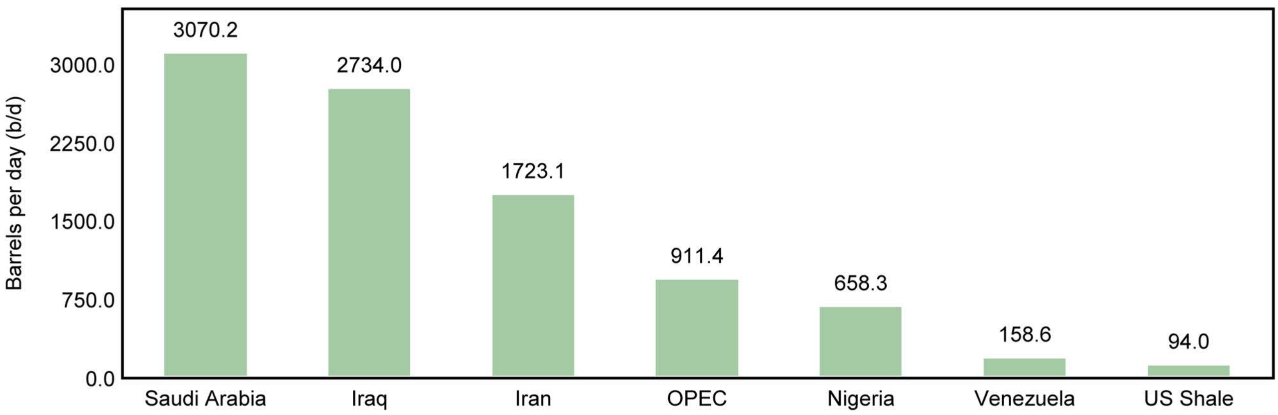
A tight oil developer would have to place ten additional wells on-stream in the first year to reach the average well productivity level of a single oil producer in OPEC countries. While this situation might be considered a setback, this sharp decline is followed by steady, low-level oil production, which helps offset the associated costs, much of which is to be discussed later.

2. Steep Decline Rates

Thousands of new wells are needed every year to grow production and fight the steep base decline in these tight oil wells, as depicted in Figure 5. These wells incur major CapEx for companies in boosting production and generating returns to investors. Hence, every aspect of the value chain must be optimized and synergized to make tight oil wells bankable. The shale market is nearly competitive, as is discussed later. Operators unable to keep up with the pace of production dynamics simply exited the market when their wells dried out, sold their assets at favorable prices, or phased out via merger and/or acquisition by other industry players.

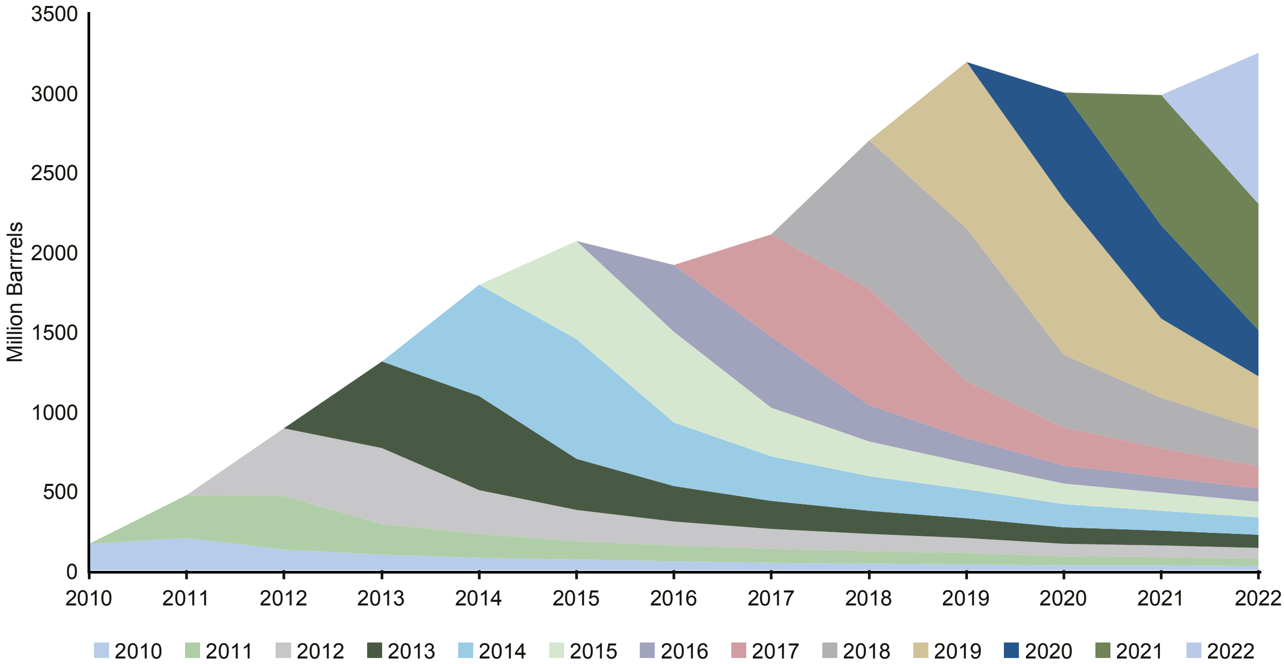
Nevertheless, short life cycles are also beneficial for many independents[5]. While conventional oil projects can take anywhere from seven to ten years to reach

Figure 4. Average well productivity – barrels per day (b/d).



Source: OPEC 2017 ASB.

Figure 5. Vintage tight oil production in million barrels per production start year.



Source: Rystad Energy.

the production stage, tight oil projects can go to production in just a few months, allowing production to respond rapidly to changes in price (Lüdtke, 2019) (Varian, 1987). Since 2010, independent producers have developed approximately 91% of U.S. wells, producing 83% and 90%, respectively, of America's O&G production capacity (IPAA 2022). However, this narrative has changed substantially with the advent of Big Oil in the shale industry, as discussed later in this paper.

3. High CapEx

Most of the development cost is attributed to drilling and completion[6] (D&C) per well. Tight oil producers, unlike conventional producers, require the extension of technology solutions such as hydraulic fracturing to extract oil from these impermeable shale beds.

According to Rystad Energy, the cost of drilling and completing a horizontal shale oil producer (excluding well tie-in and transportation costs) was in the range of $4 to $6 million barrels per well as of 2022. This, of course, varies from one operator to another and across basins depending on other factors such as geological factors, well depth, length of the horizontal wells, proppant[7] intensity and, most importantly, favorable oil prices. The overall unit cost of production ($/barrels of equivalent) has been declining, driven by the increased returns to scale driven by technological advancements and the capital discipline achieved by developers following the collapse of oil prices in 2014 (U.S. Energy Information Administration 2016), where the capital cost of a tight oil well was in range $7 to $8 million.

Section 2: How Has the Financing of the Tight Oil Sector Evolved?

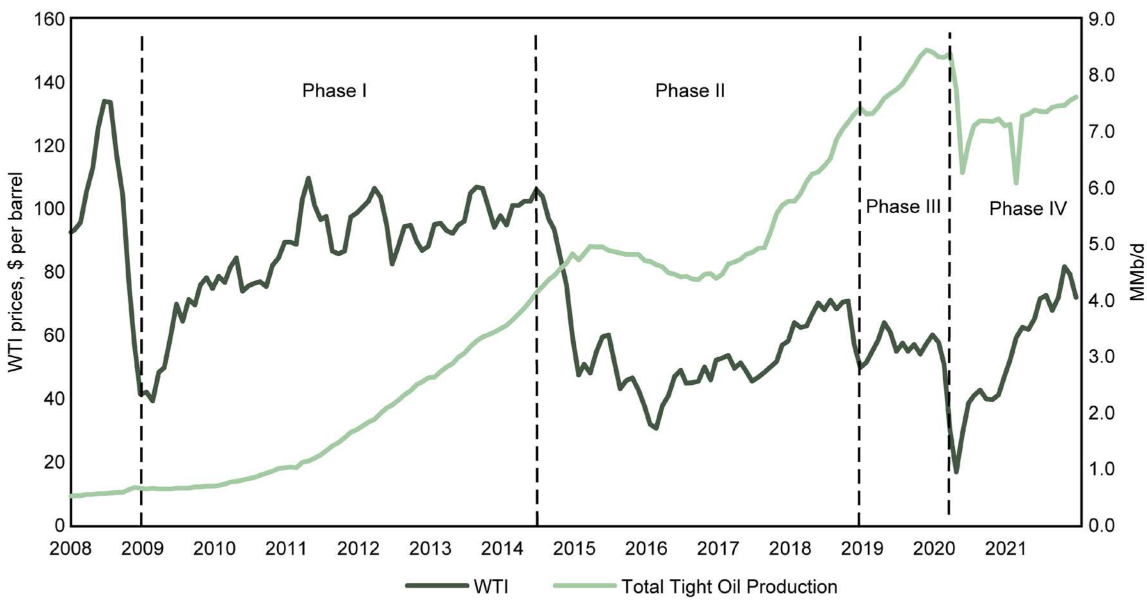
Historically, tight oil production growth has been correlated with oil prices and cash flows pouring into the sector. Figure 6 describes the four different phases that the tight oil sector has undergone compared to the NYMEX West Texas Intermediate (WTI) price. Each of these phases is described below.

Phase I – First Rush (2008-2014): After the slow economic recovery following the financial crisis in 2008 and favorable oil prices, banks were eager to make collateralized loans, essentially treating oil below ground as reserves to be valued at oil future curves with future prices between $80 and $100/bbl. Subsequently, U.S. shale production went from 0.5 million barrels per day (MMb/d) to 5 MMb/d.

Phase II – Downcycle Innovation (2014-2018): Oil prices dropped, and the narrative changed. The shale sector responded with cost-cutting, high-grading, and technical advances to maintain and grow the level of production. Banks decided to suspend and withdraw lending to shale developers. However, an influx of private equity investors rescued the shale industry, taking a bet that oil prices would recover in the short term, which did occur and stabilized from mid-2016 until early 2019.

Phase III – Investor Demands (2018-2020): Private investors demanded returns and urged developers to move away from the growth strategy adopted in previous years. Few operators reported positive cash flows (Al Suwailem and Selemankhel, Are Bankruptcies Healthy for the Tight Oil Sector? 2020). Most were relying on self-finance to leverage their operations to pay their investors. As a result, access to capital markets was drying up.

Figure 6. Tight oil production in million barrels vs. NYMEX WTI prices.



Source: EIA, 2021.

Phase IV – Private-Public Diversification (2020-Present): Another significant drop occurred due to the demand destruction caused by COVID-19. Access to capital has been choked. The spot WTI price started the year at $60 and plunged to below zero on April 20, 2022. Due to OPEC+ actions in cutting production by approximately 10 MMb/d, oil prices started to rebound, and tight oil production started to claw its way back up; however, currently, tight oil production is squarely feeling environmental, social, and governance (ESG) pressure. This era has been characterized by capital discipline focused on profits and returns rather than on production growth. Investment in the shale sector and the O&G industry as a whole has been constrained. Some major IOCs, especially European-based IOCs, have been turning green, thus cautioning hedge funds and the investment community concerning the future of the O&G industry. Self-funded independents, in contrast, have remained active throughout this period.

Dynamic Innovation in the Shale Industry

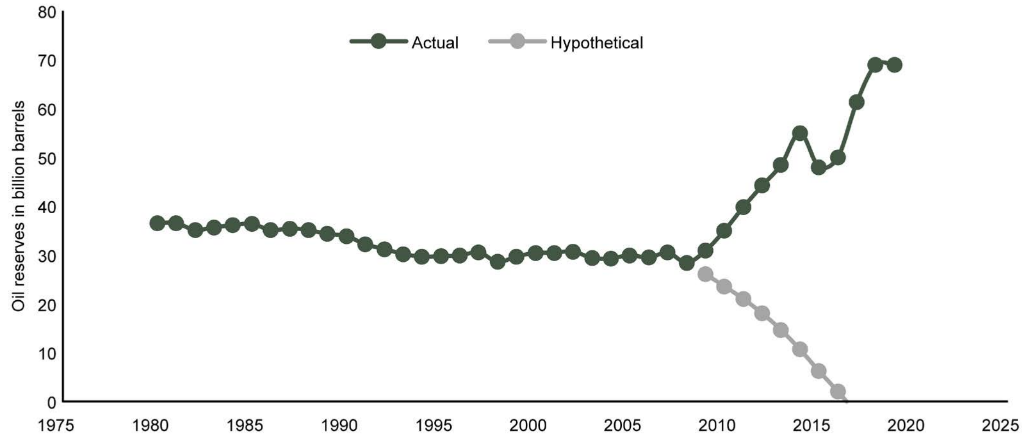
In the beginning, there were few companies including Standard Oil and the Anglo-Persian Oil Company (now BP). These operators were initially driven by curiosity and determination to explore and extract O&G, often in uncharted terrains and environments. They developed an ecosystem that embraced failure as lessons were learned, and they were more focused on growth than on returns. For instance, oil was discovered in the Dammam oilfield in Saudi Arabia after six wildcats were drilled in various regions to which these companies were unaccustomed. Such risks were highly esteemed. However, their entrepreneurial spirit abated as the companies grew and their operations became more complex. For decades, Big Oil firms believed that they could survive with out-of-date technologies and did not seek the latest and greatest technological breakthroughs. These firms became risk averse, and their business models focused on extensive oil development and megaprojects that maximized their long-run returns on investments (Al Suwailem and Williams, Integrated Oil Companies and the Quest for A Transition: How Are they Coping with Climate Change? 2022). However, this phenomenon is not confined to the O&G industry, as many industries, including high-tech and healthcare, experienced similar trends.

The pace of technological adoption and propagation in the O&G industry is slow relative to those in other industries. For instance, the first horizontal well was drilled in Texas in 1929 (National Driller 2020). The first hydraulic fracturing experiment was performed in 1947, and its application was commercialized in 1949 (King 2012). Even though these technologies were known and commercialized, it took nearly half a century to scale them up in the shale sector. Independent operators made breakthroughs by working diligently on different fracking processes and well architectures to bolster the level of O&G extraction from shale deposits using technologies developed by oilfield service companies such as Halliburton and Schlumberger (Al Suwailem and Williams 2022).

Despite the U.S.'s immense amount of shale assets, major operators stuck to the norm and developed conventional O&G fields up until the early 2000s. U.S. oil production peaked in the early 1970s, and the industry reconciled itself to its inevitable decline. As a result, major U.S. O&G companies were focused on exploiting O&G assets overseas, and many independents faced an unavoidable problem: the U.S. was running out of oil. Had it not been for the tight oil boom, assuming that historical production levels were unaffected and holding all other factors constant since 2008, the U.S. would have effectively run out of oil by early 2017 (Figure 7).

In the 1980s, George Mitchell experimented with applying different hydraulic fracturing techniques to exploit gas from the Barnett Shale. Nevertheless, his attempts were unsuccessful, and Mitchell Energy was obliged to sell many assets to stay afloat (Yergin 2020). In 1997, one of Mitchell Energy's shale gas wells, aided by injecting water, sand, and a chemical mixture (rather than more expensive foams and gels), proved that fracking could be financially feasible (Gertner 2013), thus paving the road to the large-scale development of shale gas extraction. Mark Papa, another shale pioneer who started as a roustabout on a drilling rig and climbed the ladder to become the chief executive officer (CEO) of EOG Resources, combined fracking with directional drilling to maximize contact with shale beds and release more gas. The above independent was one of the few who ventured into the Bakken shale and discovered the oil and condensate-rich Eagle Ford Basin (Helman 2013). Soon, many independents rushed to exploit shale gas. Shale gas was the

Figure 7. Actual vs. hypothetical U.S. oil reserve trends

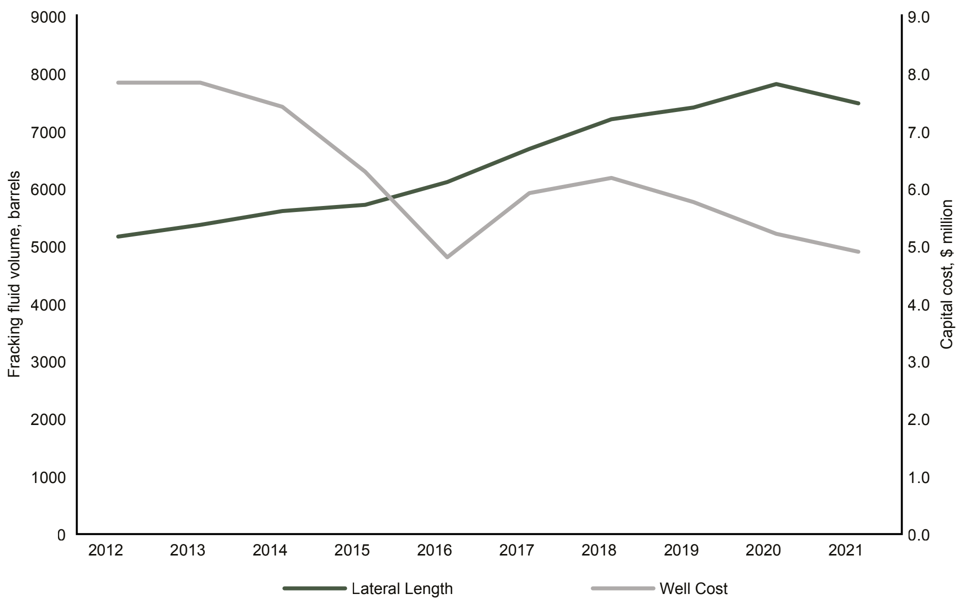


Source: KAPSARC analysis based on 2021 BP statistical review data

starting point, but liquid-rich systems were the value multiplier, and technology spillover was extended to tight oil beds, where many operators successfully exploited oil from shale formations (Figure 3).

Technological innovation did not stop there, as breakthroughs and improvements continued to bolster the O&G value chain, of which fracking and directional drilling were the technological triggers. Advances in fracking fluids and horizontal lateral length have gradually increased well productivity and "biased growth" while optimizing D&C costs. An example from the Eagle Ford Basin is illustrated in Figure 8:

Figure 8. Dynamic technological improvement of an average oil well in the Eagle Ford play.



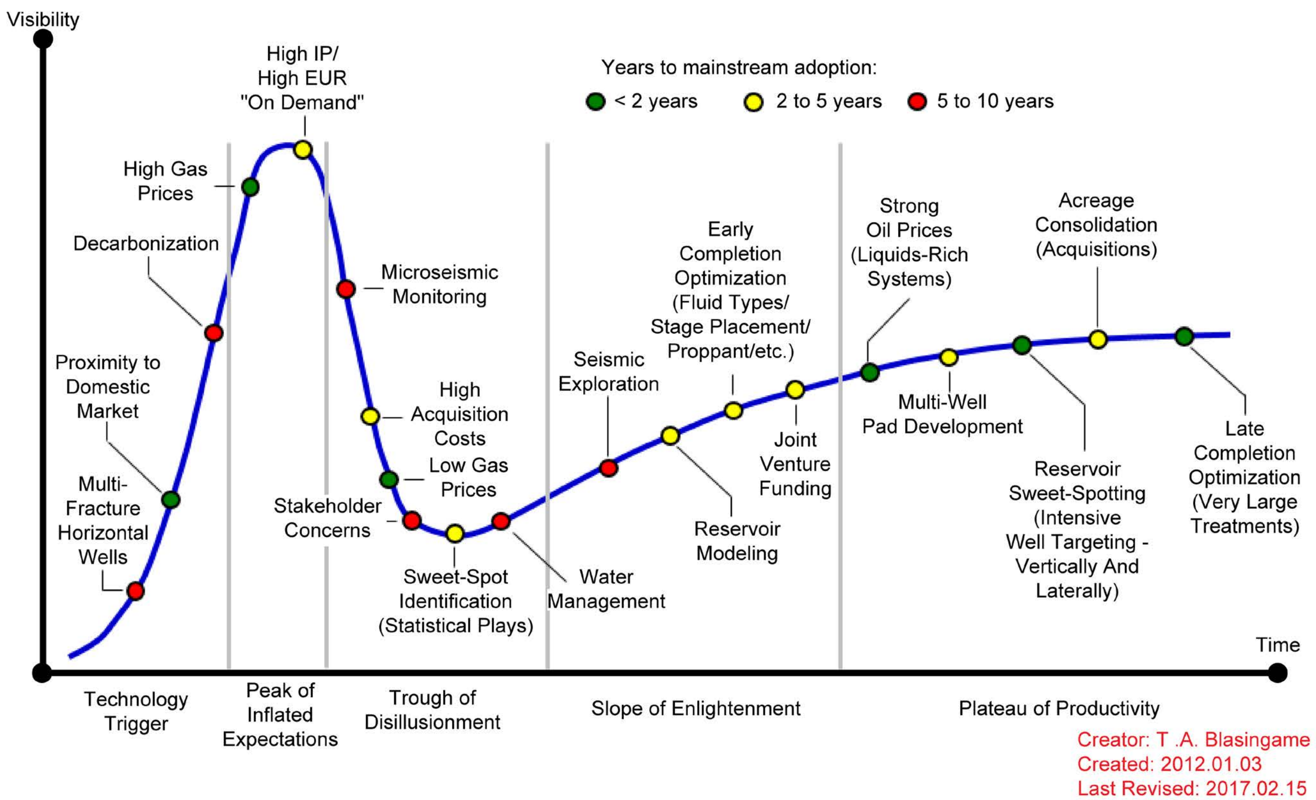
Source: Rystad Energy.

Most of the innovation was geared toward optimizing costs across the O&G value chain, especially above ground, where applications of sweet spotting[8] through directional drilling and multiwell pad[9] development operations have significantly bolstered efficiency, reduced development costs, and maximized returns on investment.

The maturity, adoption, and social applications of emerging technologies exhibit cycles including updates, a trough of disillusionment, and a plateau that varied from one technology application to another, as is best described in Figure 9. Innovations in D&C, favorable commodity prices, and the availability of infrastructure and nearby markets to accommodate increased production levels were the primary triggers profoundly impacting shale exploration and development. The truth is that there is always a "hype" point for an emerging technology when reality sets in, with economics prevailing. Technologies such as sweet spotting and multiwell pads were not perceived as revolutionary compared to fracking and horizontal drilling as much as they were perceived as technologies that help sustain oil production levels and generate steady revenue streams for operators.

A low oil price environment like that experienced during the pandemic has caused many operators, such as Chevron, to reduce their CapEx in developing tight oil fields (Reuters 2020). Many

Figure 9. Progression cycle for unconventional resources.



Source: Modified Gartner-Type Curve by Dr. Tom Blasingame.

independents have had to shut down their wells until oil sale prices become economically feasible so that they can resume production (Blas 2020). However, after the OPEC and some non-OPEC producers (OPEC+) took action in May 2020, prices started to rebound, reaching attractive levels for investors by the second half of 2021 and maintaining healthy levels during 2022 to the point that production levels have reached their prepandemic levels in the Permian Basin.

Section 3: Rise and Fall of Independents

Most tight oil independents[10] followed George Mitchell and other industry pioneers, adapting their techniques to exploit and produce tight oil. The entry of small players and the widespread technological adoption to exploit and extract shale hydrocarbons mimics the California Gold Rush, which started in the mid-1800s with the discovery of gold deposits in riverbeds (Santos 2002). After the decline in gold mining in Appalachia and the destruction of the Civil War (Craig and Rimstidt 1998), the California Gold Rush was initially driven by blind optimism. The decline in the use of conventional oil in the U.S., along with the financial destruction of 2008, created the same conditions that drove shale's explosive first phase of growth, as depicted in Figure 6. The blind optimism in the shale sector was driven by concerns over "peak oil" supply as early as 2004, and a decline in the level of oil production is irreversible (Bardi, Peak oil, 20 years later: Failed prediction or useful insight? 2019).

Many oil operators have been competing to exploit tight oil in a market driven by high oil prices that enable the unlocking of these assets using said technologies. Dynamic innovation and know-how spillover have resulted in positive production externalities across the entire U.S. oil industry, encouraging more independents and later IOCs to enter and invest in the exploitation of tight oil assets. Similarly, the first tight oil boom took place primarily in the Bakken and Eagle Ford Basins, with their production peaking in 2013 and 2014, respectively, as depicted in Figure 2. Later, the Permian Basin picked up momentum, and its production in 2019 momentarily exceeded crude production in the Ghawar oil field, Saudi Arabia's largest oilfield (Jacobs 2019).

Another critical factor contributing to the California Gold Rush was the need for land and mineral rights ownership laws, regulations, and enforcement mechanisms. At the time, California, which was annexed from Mexico and became a U.S. state in 1848, had no private property laws, no licensing fees, and no taxes to bar entry into this nascent market; thus, many prospectors ventured in waves to California to exploit gold (Rawls and Orsi 1999). State and local governments gradually stepped in to regulate this nascent market. Moreover, the mining sector took a blow when hydraulic mining, to be discussed in detail, was banned.

Unlike the California Gold Rush, the U.S. tight oil industry was able to thrive under a highly structured regulatory regime. The exploration and development of hydrocarbons comprise one of the most regulated sectors and one of those sectors that offer hefty incentives via incentive pricing, tax credits, research and development (R&D) funds, and many other benefits. The earliest market intervention mechanisms that have implications for the shale sector can be traced back to the early 1970s following the Organization of Arab Petroleum Exporting Countries' (OAPEC's) oil embargo, where the U.S. had to reassess its dependence on foreign oil imports. By 1975, the government imposed restrictions on crude oil exports. U.S. oil production peaked in 1971 and declined until the first tight oil boom in 2008. At the federal level, examples of historical government interventions include the Natural Gas Policy Act of 1978 and the Crude Oil Windfall Profit Tax Act in the 1980s, with the latter having provisions, including tax breaks, that lasted until 2003 (Wang and Krupnick 2013). Such incentives drove entrepreneurs such as George Mitchel to enter the shale space and pave the road for the first tight oil boom.

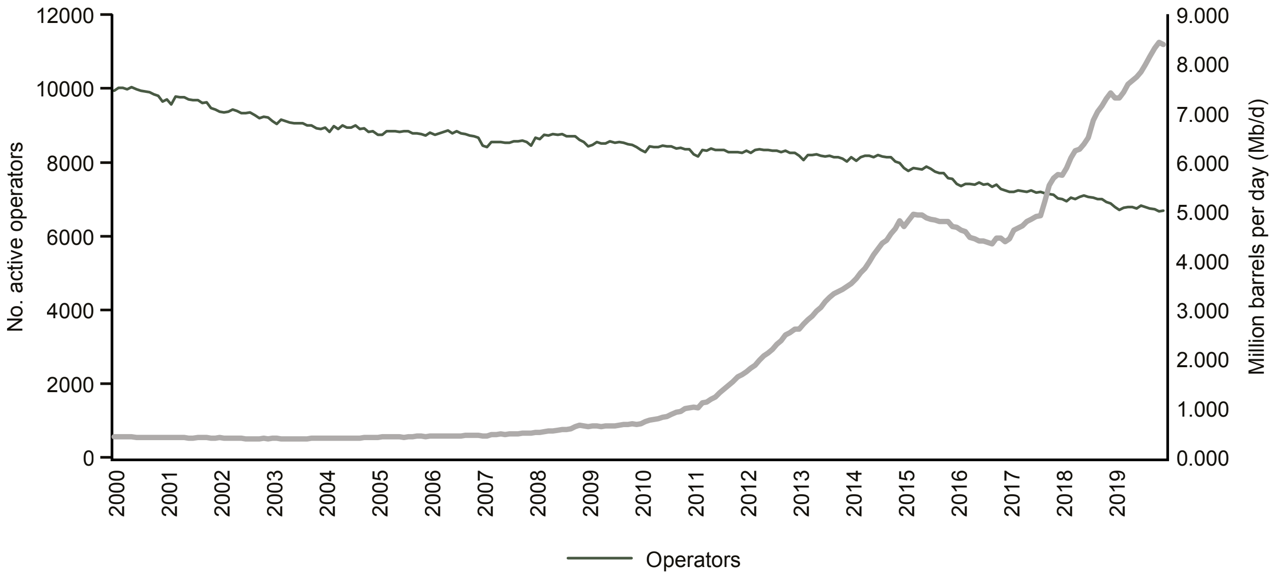
The second tight oil boom thrived after the removal of a 40-year ban on oil exports, removing restrictions on U.S. domestic production during the presidency of Barak Obama and with the influx of private equity investors pouring cash into the shale industry. The tight oil sector further flourished when OPEC members implemented quota systems to cut back on production in 2015 and the economic sanctions imposed on Venezuela and Iran by President Trump's administration, limiting the amount of oil exports of both major key oil exporting countries. Subsequently, U.S. tight oil production was on the rise and reached a record volume in 2019 prior to COVID-19.

In terms of market structure, around 10,000 active operators (primarily independents) exploited oil from these basins in 2000, as illustrated in Figure 10. These operators financed their operations through loans or equity shares to drill and complete more wells and expand their operations. When the wells dried out or ventures were not able to grow, companies started to either exit the market, undergo mergers and acquisitions (M&As) or, in a worst-case scenario, file for bankruptcy.

As for bankruptcies, there have been over 200 bankruptcy filing cases by several independents in U.S. courts since 2015, with not all of these independents being tight oil developers (Haynes and Boone, LLP 2020). This number is relatively low compared to the total number of active operators in the oil industry. Some of these producers were focused on gas, which is outside the scope of this paper. Nevertheless, most of these companies have emerged from bankruptcies after successfully restructuring their debt and selling some of their assets to other more experienced developers who have the financial cushion to undertake these developments (Al Suwailem and Selemankhel 2021). The debt obligation of many bankrupt independents has greatly improved with the recovery of oil prices in early 2022, the filings of which Haynes and Boone, a law firm monitoring bankruptcies in the energy sector, has stopped tracking (Baker 2022).

Because of the nature of tight oil, wells tend to exhibit a hyperbolic trend with very high initial commercial production levels, followed by a steep decline and then a plateau. The tight oil well

Figure 10. Historical U.S. tight oil production and monthly active oil operators.

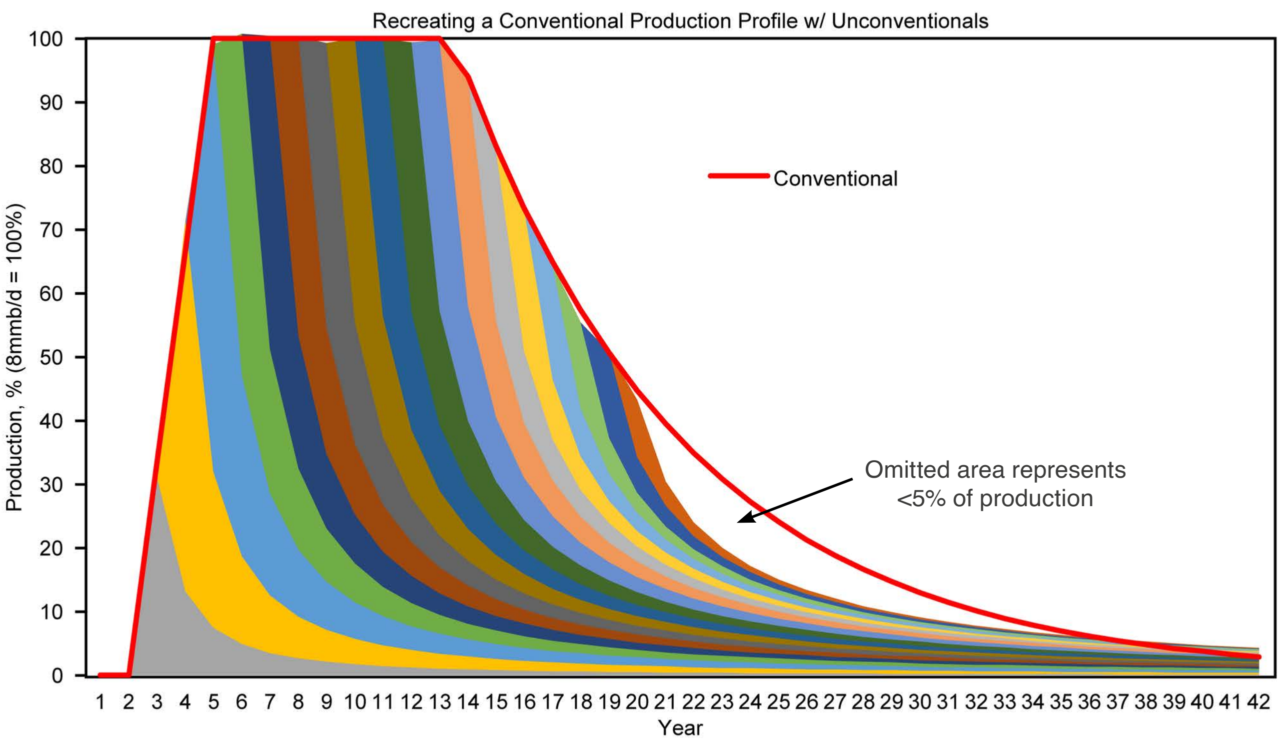


Source: KAPSARC analysis based on Rystad Energy and the EIA.

lifespan is between 20 and 40 years, as depicted in Figure 11. Despite the low volumes produced at later stages (long-tail production) compared to the initial high-level production period, this condition provides a cushion for oil operators. Large-scale producers have a steady flow of revenue to finance their operations and growth strategies in the shale sector as long as volumes are above breakeven prices. Nevertheless, regardless of whether maintaining or increasing production, continuous drilling is required to offset the sharp decline in production levels among current producers.

At the same time, the U.S. shale industry has proven itself resilient to economic downturns and able to consolidate and create value during times of falling and low oil prices (Evans et.al., 2016). M&A deals in the shale sector became more prominent following the oil recession that started when the U.S. crude oil purchase price fell from $98.68 in June 2014 to only $54.86 in December 2014 (EIA, 2023). In 2014, M&A activity among U.S. operators reached $53.5 billion, the highest level recorded to date at that time (S&P Global, 2021). As only two examples of notable acquisitions, Devon Energy acquired George Mitchell's company in 2001 for $3.1 billion, increasing Devon's hydrocarbon reserve base and expanding company operations in new frontiers (Sidel and Cummins 2001), and in 2020, Occidental Petroleum acquired Anadarko Petroleum to diversify its portfolio and increase its footprint in the Permian and other basins and deepwater operations (Spencer 2019).

Figure 11. Recreating a conventional production profile with unconventionals.



Source: KAPSARC analysis based on Rystad Energy, 2023.

M&As provided opportunities to consolidate new assets, increase the degree of focus and resources on core assets and divest from noncore assets, creating “economies of scope” and reducing development costs by exploiting economies of scale or entering a new territory or business area through “geographical or product diversification.” However, even with these actions, a Deloitte report on the top 100 shale deals by value since 2014 indicated that more than half of the deals realized “below-average operational (free cash flow) and shareholder (total shareholder returns) gains” (Deloitte 2022). As a result, the number of independent operators has declined since the early 2000s. By December 2019, the number of active producers declined to about 6,600 operators from a peak of 10,000 in the early 2000s, as depicted in Figure 10.

The U.S. shale industry has shown resilience to economic downturn, maintaining a base production level, despite numerous bankruptcy filings. Between January 2015 and mid-2020, about 69 of the approximately 2,160 small and medium-sized independent oil companies operating in the tight oil sector filed for Chapter 11 bankruptcy protection[11], and most emerged successful (Al Suwailem and Selemankhel, Are Bankruptcies Healthy for the Tight Oil Sector? 2021). As yet another display of industry resilience, shale producers have demonstrated an astute ability to increase profitability through reduced cost. In the years prior to the COVID-19 pandemic, shareholders became tired of low returns (Eberhart 2022), resulting in a significant divestment from the O&G sector, particularly from shale. Indeed, upstream O&G CapEx fell, after reaching a peak in 2014, to $481 billion in 2015 and to $348 billion in 2016. Since then, investment in the O&G sector has not yet returned to its 2015 levels (Arboleda Larrea and Al Sadoon 2022). It is also fair to say that climate change pressure, among other confounding variables, has played a role in this divestment, but returns remain the most significant variable. To weather the storm, tight oil producers (primarily independents) are placing more emphasis on capital and fiscal discipline rather than on high-intensity drilling. For more prominent players, tight oil investments provide different degrees of risk exposure. Long-tail production allows these players to sit on residual, steady streams of cashflows to hedge against exposure in case of supply shocks. By entering the shale realm, large firms have been attempting to transform tight oil development to mimic conventional oil development so that they do not have to change their typical strategies (what is the typical strategy?). Much of the above content is covered in the following sections.

Section 5: Has Technological Innovation Reached a Threshold in the Shale Industry?

The O&G industry continues exploring new frontiers and technologies with which to improve efficiency and maximize returns on investment. Nevertheless, in the 1990s, major technological breakthroughs were not foreseen in the short term. Even if such breakthroughs occur, they will not stop the unavoidable truth: tight oil supplies will peak and decline in the medium to long term, similar to U.S. conventional oil production in the early 1970s. Tight oil is merely a short-term blip in the long-term trend of shrinking levels of oil production. To illustrate this point, let us compare this situation to the California Gold Rush in terms of how the role of technologies has influenced development.

At the beginning of the California Gold Rush, prospectors could retrieve loose gold from streams and riverbeds using simple techniques, such as panning, a technique used in agriculture to separate the grain from the chaff. To scale up operations, miners deployed different innovative methods such as cradles, rockers, and other methods to process larger volumes of gravel from which to separate gold (Young and Lenon 1970).

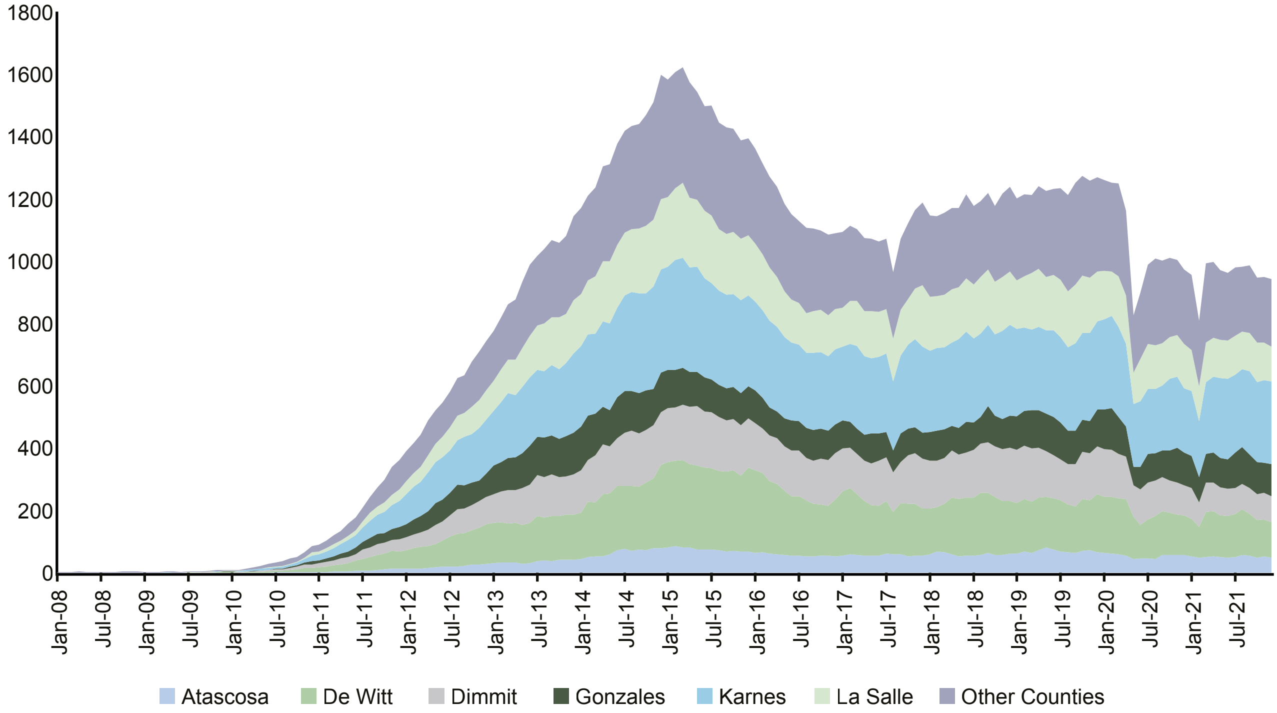
As it became more challenging to find and extract gold in riverbeds, miners engaged in coyoteing, which involved digging 6- to 13-meter shafts deep into placer deposits along a stream. Tunnels were dug in all directions to reach the richest veins of pay dirt. By 1853, hydraulic mining, which used jets of water under high pressure to dislodge rocks (Young and Lenon 1970), had a similar impact as that of hydraulic fracking on the O&G industry. This technology was subject to numerous lawsuits because it disrupted rivers and streams and, thus, was abandoned in the 1880s (Craig and Rimstidt 1998). The ban on hydraulic mining brings to our attention the increasing negative sentiments toward hydraulic fracking in the O&G industry and the different reports concerning its role in inducing seismic activity and contaminating fresh aquifers.

Hydraulic mining occurred when the California Gold Rush peaked, and many prospectors were exiting the gold mining sector, as the easy-to-extract gold in riverbeds had already been extracted. This technology was not accessible to everyone; it was capital intensive and beyond the reach of many prospectors, thus presenting a pecuniary barrier to entry. The change in mining techniques represents the story of the evolution of the California Gold Rush, transforming individual efforts into a corporate phenomenon.

Similarly, tight oil developers have been targeting the most geologically favorable parts of basins, known as sweet spots, which have declined in number due to excessive depletion. For instance, in the case of the Eagle Ford Basin, whose level of tight oil production peaked in late 2014, the most productive zones were found in 5 out of 28 counties, as depicted in the figure below.

Much of the abovementioned innovation and R&D has been poised at improving productivity through enhanced oil recovery and water management applications to prolong asset life and minimize undesired water production (Figure 9). As the tight oil sector is moving toward the manufacturing mode and because of the heightened awareness of climate change among people, the incentive to develop new technologies is likely to be abated, especially if

Figure 12. Eagle Ford Basin production contribution per county.



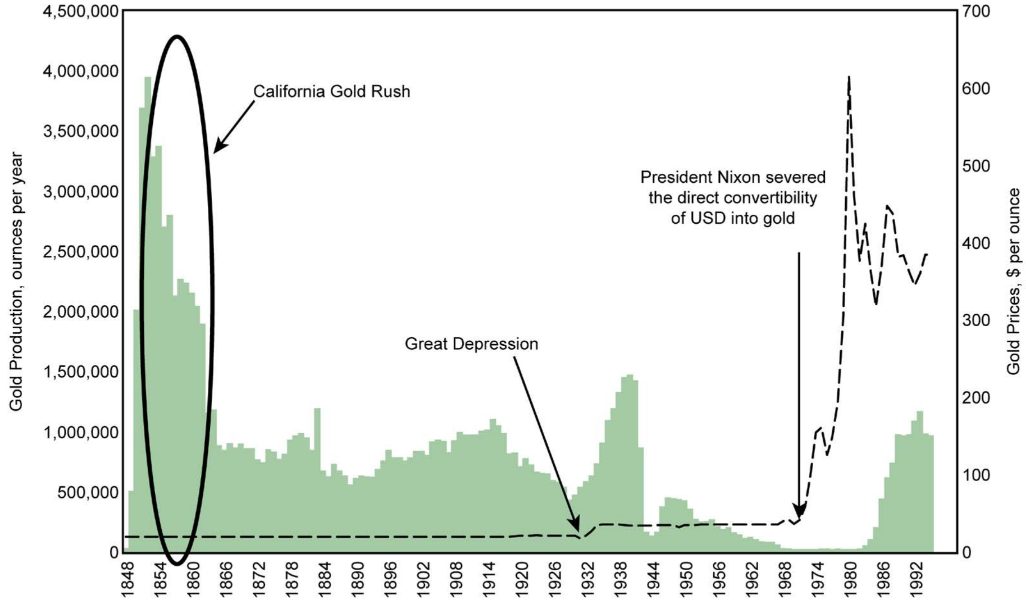
Source: Rystad Energy.

these technologies add additional operational costs for operators; thus, many operators would refrain from developing such new technologies.

In summary, shale development may be similar in many respects to the that of the California Gold Rush. Future breakthroughs in shale development may not be as revolutionary as those in the early days; they may add a new level, marginal oil production, but are designed primarily to extend the life of the wells, as illustrated in Figure 9, and are unlikely to arrest the imminent decline in the level of oil production in the foreseeable future. Hydraulic mining, which relies on high-pressure water jets to dislodge rock material, was deployed in 1853 to excavate gold during the California Gold Rush. A peak supply of gold had already occurred in 1852, despite the marginal benefits brought about by this technology. The decline in gold supply was not caused by demand distortion since the U.S. dollar value had been convertible at a fixed rate per ounce of gold prior to 1971 but more by a supply deficit (Figure 13).

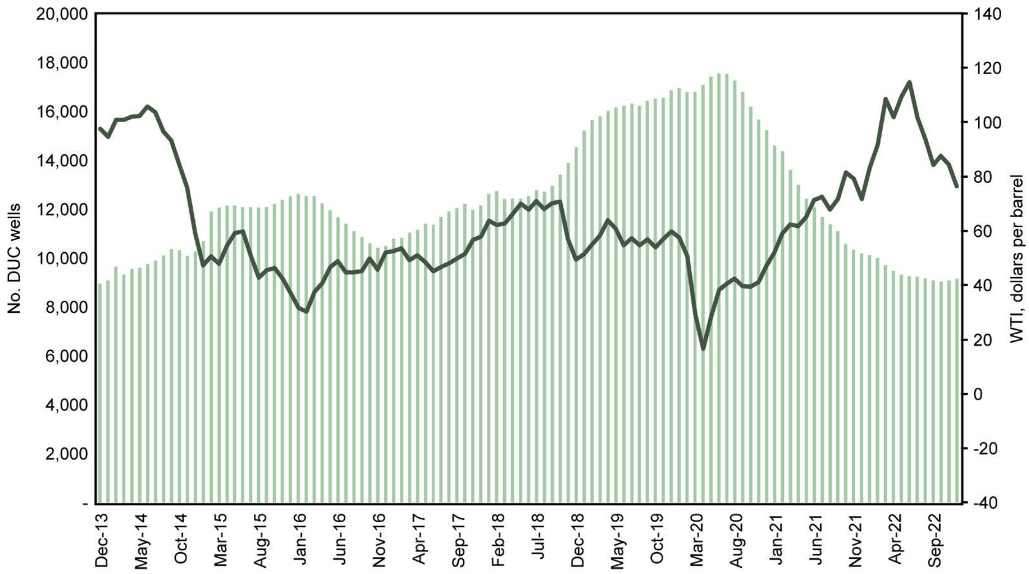
In addition to sweet spots, drilled but uncompleted (DUC) wells are another low-hanging fruit tapped into by many operators, especially during the COVID-19 pandemic. Most of the developments in shale space have been in new uncharted territories with limited pipeline and processing infrastructure. The pace of well tie-ins and the unprecedented demand for proppant, acid, and fracking equipment had not been keeping up with the pace of drilling. Thus, the number of DUC wells has been piling up over time. Following the demand destruction exacerbated by COVID-19, operators have exploited different means through which to further optimize the entire O&G value chain by reducing capital and operational expenditures, especially those associated with new drilling operations, and focusing on bringing DUC wells on-stream. The number of DUC wells in the shale sector has dropped significantly, by half, over a span of two years, despite the disruptions in supply chains during the pandemic, where many operators were challenged to procure new equipment and pipelines to tie in the wells (See Figure 14).

Figure 13. California gold production and gold prices.



Note: Gold prices are denoted by a solid black line (National Mining Association n.d.), and gold production is depicted as blue columns (Craig and Rimstidt 1998).

Figure 14. DUC wells in the shale sector vs. WTI.



Source: EIA, 2023.

On a different note, maximizing net present value (NPV) is one of the reasons that the oil industry ventured into shale in the first place. The incentives are still there to increase the upfront production value. However, increasing the longevity of wells is a hedge for larger firms. Some might argue that the advent of Big Oil is transforming the shale development landscape, driven by these companies' project management expertise and capital cushion to boost tight oil production. In the following section, we analyze the role of Big Oil in the tight oil sector.

Section 6: Advent of Big Oil

Big Oil or IOCs[12] such as U.S.-based Chevron Corporation or foreign-based BP were latecomers to the tight oil industry. These corporations invest primarily in finding and developing large, conventional O&G fields with horizontal breadth and greater vertical depths. Developing these assets requires fewer wells per barrel, where the overall production rate is higher and lasts longer. While these fields require long investment cycles, especially in terms of operations, their breakeven costs tend to be lower.

After a well has passed its most prolific years, or if the remaining volume requires additional operational and capital investment, it is suggested that IOCs shed their liabilities by divesting from these mature fields and selling them to independent producers specializing in small-scale mature operations (Van Vactor 2010). An example is BP's exit from the Prudhoe Bay oil field in Alaska. After nearly 60 years of operating in the field, the company sold its Alaskan proprieties for $5.6 billion to Hilcorp Energy in August 2019. Prudhoe Bay's sell-off coincided with BP's expansion into the shale industry, as it acquired BHP Billiton's shale assets for $10.5 billion in 2018 (Bousso and Nadkar 2019).

Most major oil companies paid little attention to shale in the 1990s, as it was deemed a contingent resource, despite its formidable volume. The operational granularity, intensity, and short well life cycles made shale an unattractive investment. As shale became commercially viable with rising oil prices, major players were eager to expand into the shale business. In addition to the size of the stake, moving from long investment cycles to shorter cycles was driven by many factors, including but not limited to investor pressure, fear of climate change policies, future market uncertainty, and plans by many to become integrated energy/power companies.

The O&G industry is cyclical; in recent years, geopolitical tensions and concerns over oil disruptions and energy security have mounted. Shale investments provide a different kind of risk exposure to exploration and production (E&P) companies. Major players see value added in terms of having shale assets in their investment portfolio and as a means to hedge against supply shocks and aboveground risks, which are part of overseas development (Balke, Jin and Yucel 2021) (Aastveit, Bjornland and Gundersen 2021).

There is a certain ambiguity about the future of oil demand given the heightened awareness of climate change and the dwindling amounts invested in hydrocarbons. The net-zero sentiment, ESG pressure, and fossil fuel shaming have become increasingly popular in the Northern Hemisphere and burden many major players. For instance, in late 2019, ExxonMobil prevailed in a lawsuit over climate regulations that began in 2015 (Peltz 2019), but more recent climate lawsuits in Europe against Shell have been resolved less favorably. In 2020,investor priorities were no longer shifting in the wake of BlackRock's January 2020 climate letter and the decision to join Climate Action 100+. Moreover, institutional investors were no longer shifting their tone but were stepping up their level of engagement to force companies to act. ExxonMobil's Annual General Meeting saw shareholders elect at least two new board members proposed by an activist investor who was critical of the company's climate stance and broader strategy.

Peak demand scenarios have proliferated, but the International Energy Agency's (IEA's) Net-Zero report is one of the most radical to date, as it advocates for a halt in investments in new unsanctioned O&G projects to meet the Paris Agreement's climate goals by 2050. This report sets forth only one path to net-zero emissions and excludes the use of offset credits. Moreover, this report assumes a lower uptake of negative emission technologies. Thus, many oil exporting countries and O&G companies bitterly resent the report and its findings. The path presented is narrowly focused and does not match industry scenarios (Al Suwailem and Rioux, Integrated Oil Companies and the Requiem for a Transition: How Are They Coping with Climate Change? 2022).

Additionally, there are speculations about the timing of the peak oil demand. European oil major players suggest that it will occur in the next two decades, while their U.S. peers expect the peak to occur beyond 2050 (Cook and Cherney 2017). European major players are heavily pressed to divest from fossil fuels and oil, while U.S. major players are not as pressured, despite talks on fracking bans and limiting drilling on federal land. U.S. oil firms are already sitting on a massive pile of permits, there are too many jobs in the sector at stake, the O&G lobby is enormous, and there are too many companies to police effectively. Conversely, the government cannot offer incentives to increase production in the O&G industry, particularly the tight oil sector. When prices surpassed $5/gallon at the pump following the beginning of the conflict in Ukraine, President Joe Biden urged O&G companies and refineries to do whatever it took to lower the costs. The only tool within the disposal of the current administration to influence prices was to release more oil from the Strategic Petroleum Reserves, which have hit their lowest levels since 1984 (Rapier 2022).

Upon their entry into tight oil, oil major players leveraged their expertise in integrated oil projects across the value chain of the O&G industry and exploited economies of scale. Unlike independents, who are risk-takers financing their tight oil projects through bank loans or equities by private investors, IOCs are primarily self-financed and undertake loans on an as-needed basis to finance capital-intensive projects (Again this piece of information on equity vs loan financing can be used earlier to set the stage for the arguments you have been making).

As fast followers, oil major players benefitted from the lessons learned by the independent pioneers. A few of such players began investing in shale assets by organically setting up partnerships with independents, with some IOCs acquiring small oil independents. ExxonMobil, for example, absorbed XTO energy in 2009 (Crowley and Davis, Bloomberg 2019) and most recently announced its plans to acquire PDC Energy to boost its presence in the Permian Basin (Valle 2023). Others hired personnel from shale firms and then bought land or obtained leases to develop tight oil fields directly, as in the case of Shell, which spent $1.9 billion in 2012 to expand into the Permian Basin (Crowley, Bloomberg Businessweek 2018).

From 2009 to 2013, these IOCs attempted to optimize tight oil operations and were challenged to integrate them into their portfolios. Big Oil companies are accustomed to a large-scale and prolonged lead-time mindset, requiring more attention to be paid to safety and protocols, unlike independents, whose priorities differ. The competitive advantage of independents relies on their brute force, freedom to experiment with “trial and error,” and rapid decentralized decision-making in drilling and completing wells and optimizing procurement processes to deliver crude oil to nearby markets.

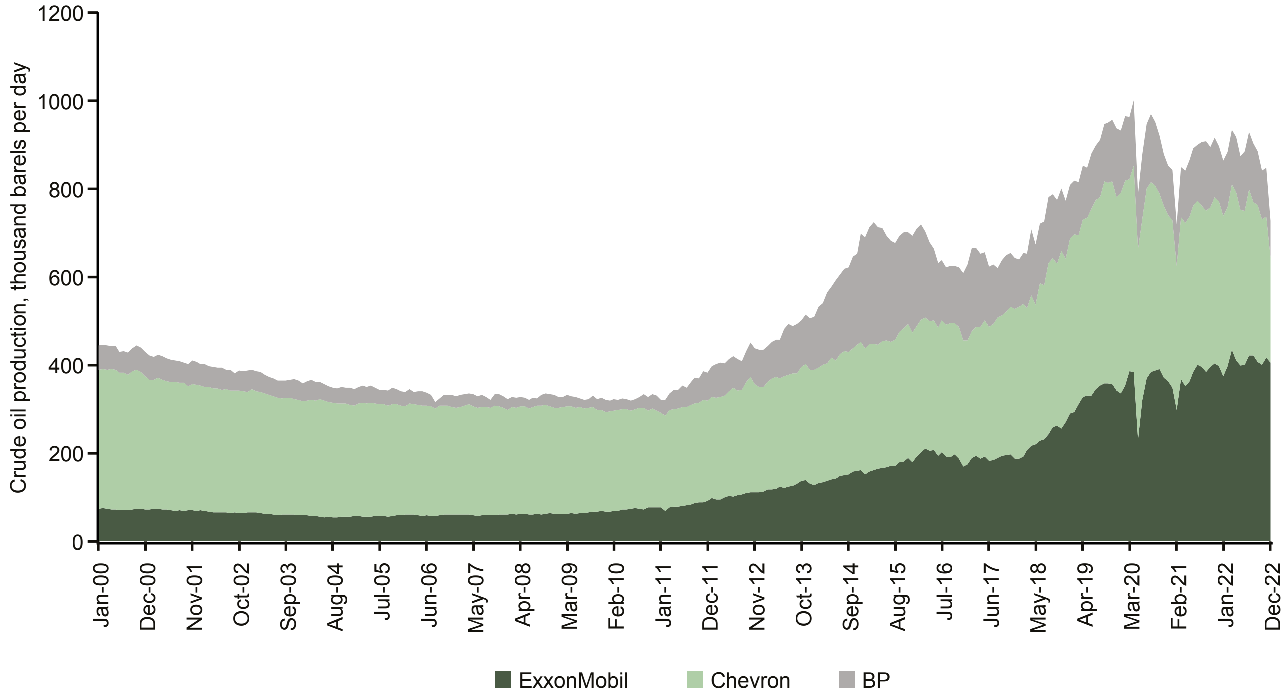
The integration process has not been easy, but the sheer size of the shale plays in the U.S. has motivated these developers to expand into the shale business, especially in the Permian Basin, and tune their business models to cope with U.S. shale assets (Figure 15).

These firms are progressively bringing economies of scale and project integration across the value chain of oil into the market. By jointly producing many wells, the share of fixed cost in overall cost decreases, resulting in the average cost of production declining, making large-scale development economically viable.

Since early 2018, many IOCs have quickly ramped up their levels of production in the Permian Basin. Due to the diversified portfolios of IOCs, they are expected to keep shale assets flowing during downturns in oil prices compared to independents. Further demonstrating the vulnerability of independents, shale pioneer Chesapeake filed for bankruptcy to reorganize and eliminate $7 billion in debt (Wethe 2020).

As eager as these incumbents are to increase their presence and capture additional market share, independents of various sizes still dominate exploration and production activities. Some of these independents, such as EOG Resources, Marathon Oil, and Noble Energy, are now rivaling IOCs in this sector, also capitalizing on the principles of economies of scale in developing tight oil fields and expanding their operations overseas. Nevertheless, the abundant technically recoverable tight oil resources entice many to invest and generate profits.

Figure 15. Tight oil production from selected major IOCs in the Permian Basin.



Source: Rystad Energy, 2023.

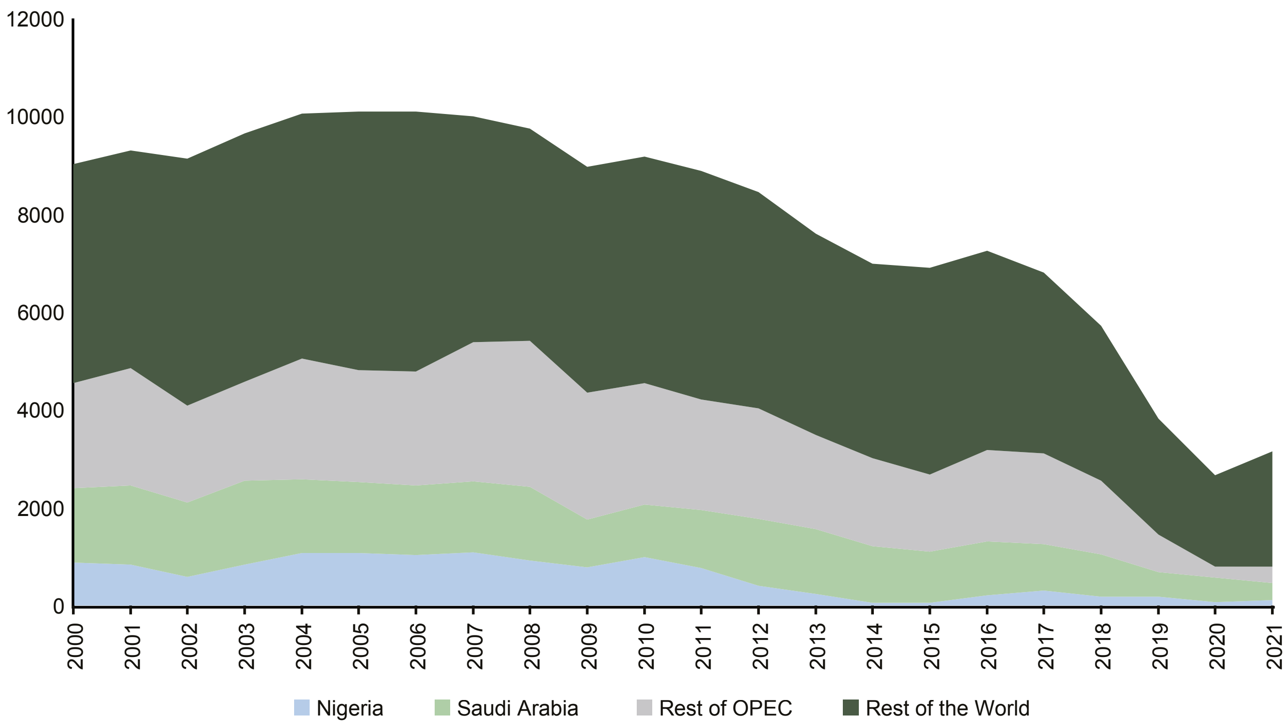
Section 7: Tight Oil Market Features

The tight oil industry replicates in many aspects the model of perfect competition described by Frank H. Knight, one of the founders of the Chicago School of Thought, in his book “Risk, Uncertainty, and Profit” (F. H. Knight 1921). Frank stated that markets are perfectly competitive if they satisfy the following four main assumptions, all of which apply to the U.S. tight oil industry:

1. Free and easy entry into and exit from all markets exist: Entry and exit from the tight oil industry in the U.S. are relatively straightforward, especially when compared to other industries, where governments exercise control over their hydrocarbon assets, discouraging entry by many players (Bayulgen 2010). Another feature differentiating the U.S. from most countries is that mineral rights below the surface in land owned by individuals or the private sector, except for federal or state land, can be transferred freely between private parties. Earlier, we saw how independents and IOCs, who were latecomers in this industry, could invest in the U.S. shale sector.

2. Products are standardized: O&G companies compete to exploit relatively standardized and slightly differentiated crude oil types in the tight oil industry. Tight oil is a light, sweet crude oil comparable to Nigerian crude oil. Moreover, the surge in U.S. tight oil production disrupted trade patterns. U.S. imports from Nigeria declined rapidly to 500 thousand barrels per day (Kb/d) in 2019, which was less than one-third of the peak of 1.7 MMb/d reached in 2003. U.S. tight oil exports were competing for Nigeria’s market share in European countries in 2019 (Browning 2019). Changes in the patterns of trade are not confined only to Nigeria and are also observed in the U.S. (Figure 16).

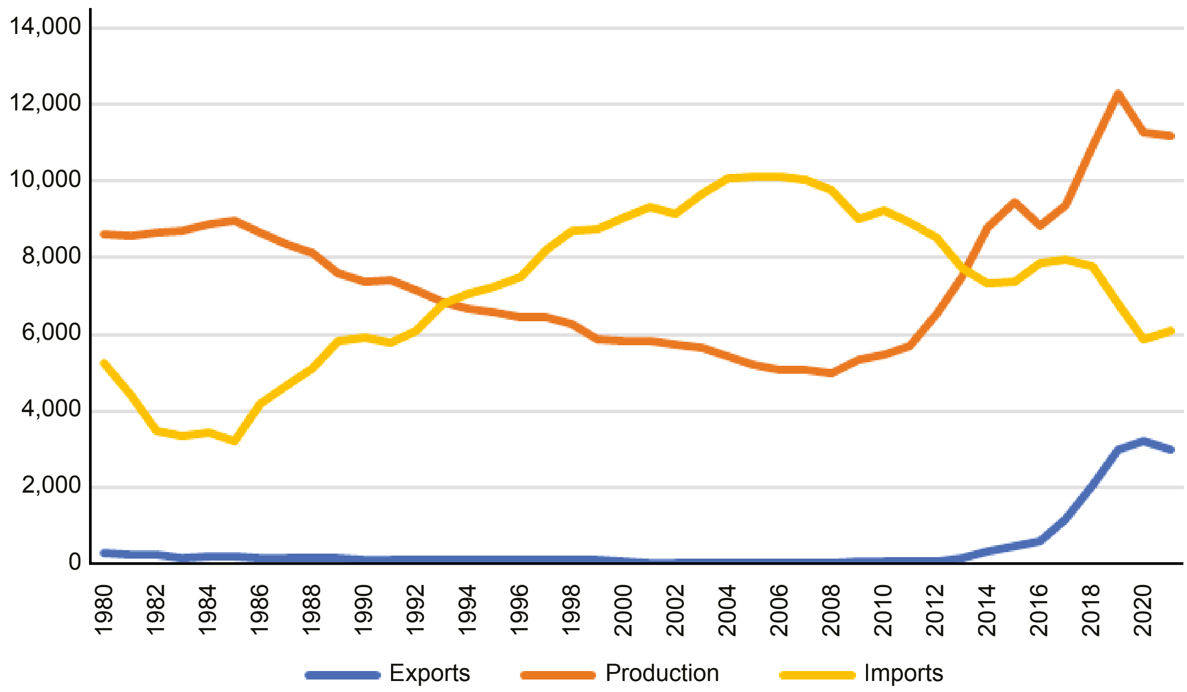
Figure 16. U.S. net crude oil imports (Kb/d).



Source: EIA, 2021.

3. There are many buyers and sellers in this market, with each maximizing its own utility or profit: The U.S. has the largest number of O&G companies worldwide. However, these producers had not been able to export their oil due to a 40-year ban on exporting U.S. crude oil overseas, with a few exceptions of course, and U.S. refineries were restricted to taking only up to a certain volume of U.S. oil. As prices started to decline in mid-2014 through 2015, the second shale revolution, characterized by adaptation, began. The industry responded with cost-cutting, high grading, and technical advances to maintain and grow its level of production. The removal of the export ban in September 2015 also supported such growth. The tight oil industry underwent another boom that lasted until the beginning of the pandemic in the first quarter of 2020, hence expanding the possibility frontiers of U.S. production and enhancing its terms of trade in oil as well as its welfare, as shown in Figure 17.

Figure 17. U.S. crude oil demand, production, and trade.



Source: OPEC Statistical Bulletin, 2022.

The above graph also illustrates the increased intraindustry trade of crude oil, where it exports light crude oil and imports a variety of crude oil to meet its relative domestic demand within the U.S.

4. Buyers and sellers know the prices: The two most popular types of crude oil are Brent Crude and WTI, which are traded on the Intercontinental Exchange (ICE) and New York Mercantile Exchange (NYMEX), respectively. They are used as benchmarks for global oil prices. U.S. crude oil has been extensively traded using WTI as a benchmark. WTI is a U.S. blend of several domestic light sweet crude oil streams. The delivery point is located in Cushing, Oklahoma, with a

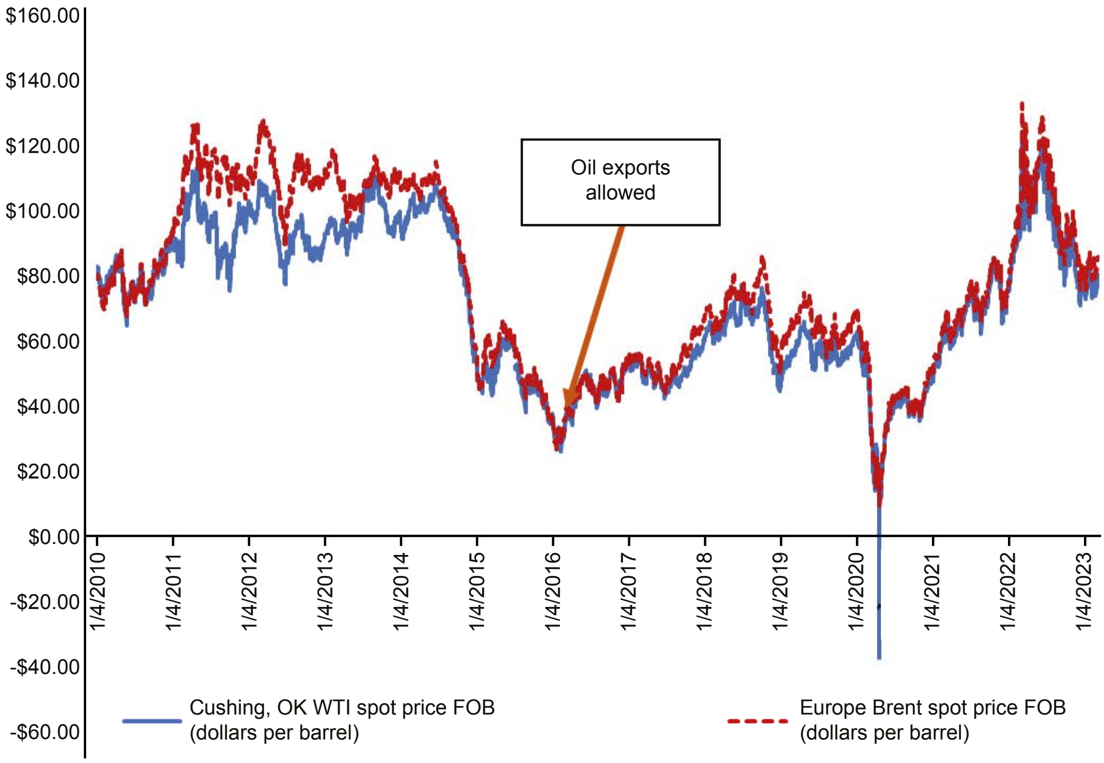
storage capacity of 90 million barrels. The hub features extensive infrastructure and serves as a critical trading hub for both refiners and suppliers.

Given its quality, WTI historically traded at a discount of $1-2 per barrel below the Brent price and $5-6 over the OPEC price. The reason for this is mainly due to the lack of storage at Cushing and the lack of pipeline capacity out to the Gulf Coast. Since lifting the ban on U.S. petroleum exports at the end of 2015, WTI and Brent relative crude prices have been converging, and the gap between them has shrunk, signifying how world prices are playing a role in price setting locally (Cunningham 2018). Concurrently, the pipeline outlets from Cushing were also expanded, which meant that the glut of WTI at Cushing was gradually absorbed.

However, in late 2017, prices began to diverge, with WTI trading at a discount of $4-5 per barrel with respect to the Brent price due to the supply oil glut driven by the second tight oil boom exceeding the amount that could be processed by domestic refineries (Figure 18). As previously explained, this bottleneck prompted the Biden Administration to reach out to the O&G industry and refineries to increase their output and reduce gasoline prices.

In summary, even though tight oil and the U.S. oil industry as a whole can be deemed a nearly competitive market, global oil markets do not behave similarly, and their forces are powerful enough to influence demand, supply, and prices.

Figure 18. Weekly spot crude prices ($/b).



Source: EIA, 2023.

Section 8: Why Can Tight Oil Development Not Succeed Outside the U.S.?

As previously mentioned, several factors have contributed to the success of the tight O&G industry in the U.S. The unique characteristics of this industry with low well productivity, steep decline rates, and high CapEx require a unique financial system, a robust and well-functioning service industry, existing takeaway infrastructure, and a grid of independent operators that are risk tolerant in a low-profit environment[13]. Such an ecosystem will not thrive without social acceptance, ease of financing, and government regulations.

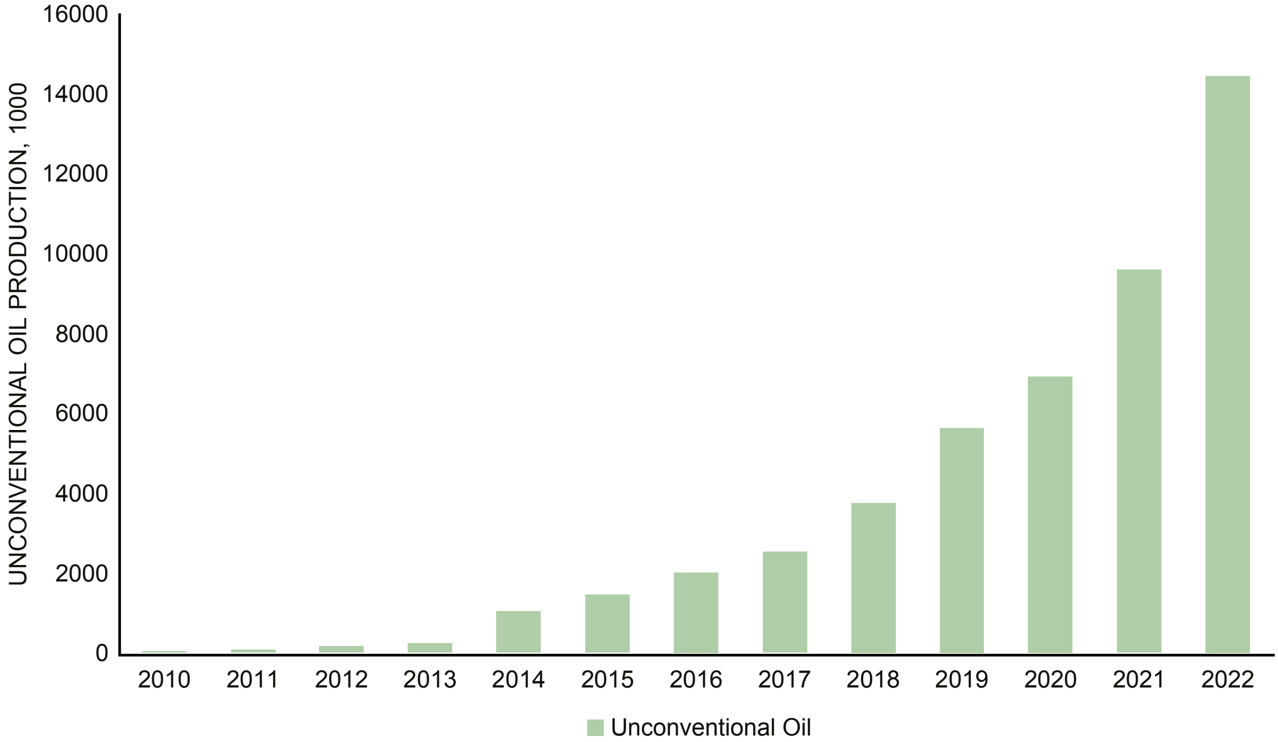
According to the IEA, by January 2019, there were 350 billion technically recoverable tight oil barrels outside the U.S. (Gould and McGlade 2019). However, the terminology used to denote tight oil barrels as technically recoverable does not necessarily mean that those reserves can be economically produced with the current technology. Thus far, only the U.S. has proven that those resources are recoverable. In theory, other countries can recover their vast tight oil resources, but no large-scale efforts have replicated tight oil development thus far. This development has seen significant advancement only in the U.S., while the shale revolution is unlikely to be replicated elsewhere, attributed to the depth of the supply chain—oil field services, for example—that support upstream operations in the U.S. Another critical factor is the ownership of subsurface resources in the U.S., held primarily by private landowners, as opposed to the state/government. The U.S. ownership model, rooted in the legal treatment of property rights, creates incentives for landowners to seek pathways for monetization that do not exist when mineral rights are owned by the state. This model cannot be replicated, absent a change in law, in most other places around the world (Medlock III 2022).

Efforts to recover shale reserves around the world have been stifled by high initial production costs. The development of Vaca Muerta in Argentina began in 2010. Production has increased over time, but the growth rates have been less aggressive than those in the U.S. shale sector, as illustrated in Figure 19, which is attributed to the lower number of players operating in Vaca Muerta. Technology spillover from international developers has helped commercialize the basin and accelerate its development (Alturki, Fattouh, et al. 2021). Nevertheless, the production cost of tight oils in Argentina remains relatively higher than most conventional crude oils produced there.

On a different note, China has a significant volume of lacustrine shale oil reserves. The production of tight oil in lacustrine fields presents lower production rates, an uneven distribution of high-yielding and stripper wells, no insights about the main controlling factors of shale oil enrichment, and no unified criteria for sweet spot selection and evaluation (Zhijun, Xinping and Zhenrui 2022). All the above characteristics drive production costs upward. Thus far, China has developed pilot tight oil projects with a production capacity of 1.86 million tons per annum (37.4 thousand barrels per day) (CNPC 2021).

The social license to operate is another critical factor that has contributed to the growth in the tight oil sector in the U.S. There is the relatively sympathetic public attitude toward O&G development in the

Figure 19. Argentina's unconventional oil production (1000 m3).



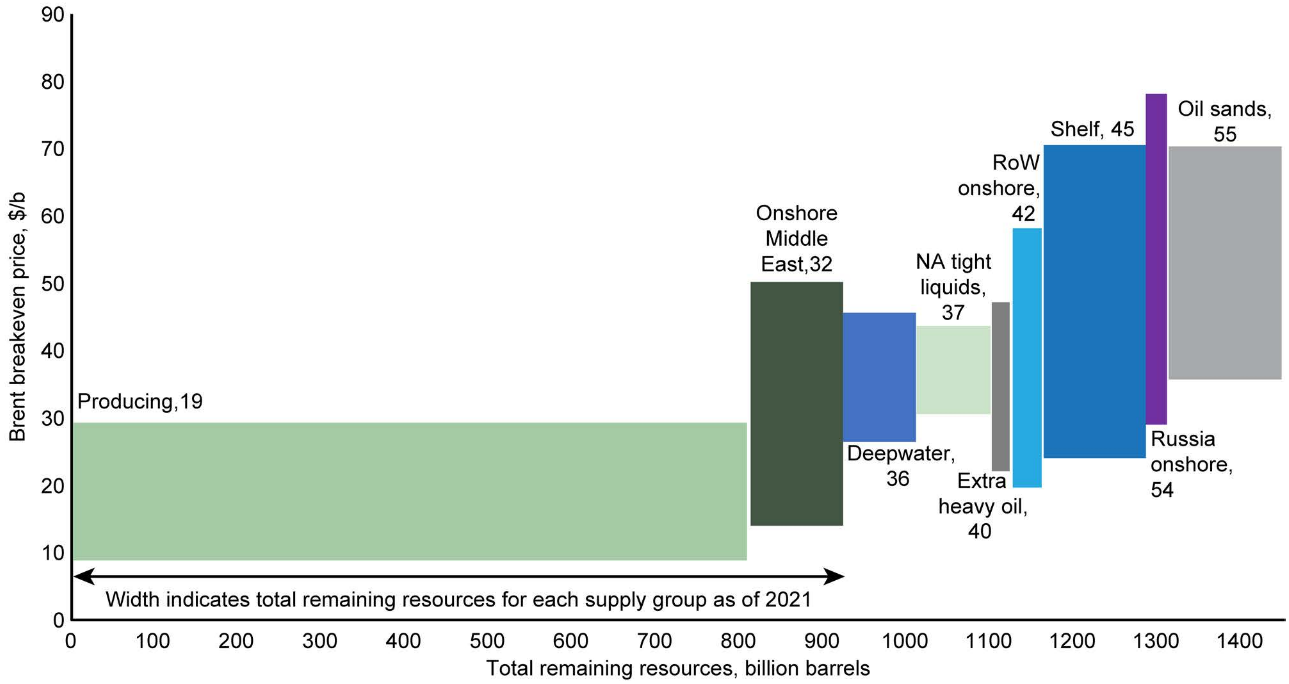
Source: Argentina's Ministry of Energy, 2023 (Argentina 2023).

U.S., given the fact that landowners stand to benefit financially from extraction—a condition not present in other countries. On a different note, public resistance to fracking over concerns related to freshwater contamination and induced seismicity have deterred the exploitation and production of shale assets in many parts of the world.

In some other cases, technology spillover from the U.S. shale industry has made exploiting international O&G fields possible. The most significant example is the Kingdom of Saudi Arabia, which is betting on producing its shale gas reserves, estimated to be the fifth largest in the world. Natural gas production at Jafurah Basin in the Kingdom is expected to commence in 2024. It is forecasted to reach up to 2 billion cubic feet per day of sales gas, 418 million cubic feet per day of ethane, and approximately 630,000 barrels per day of gas liquids and condensates by 2030. The investment will amount to $68 billion over that period and is expected to total more than $100 billion overall (Glackin 2021).

Figure 20 illustrates the long-run supply curve of crude oil reserves. An optimal global drilling plan would see the lowest-cost reserves developed first, with higher-cost reserves developed later in the planning period. The development picture is complicated by the national location/ownership of the reserves, taxes, environmental concerns, and the high volatility of world oil prices. Shale oil is relatively more expensive to develop than are onshore reserves in the Middle East, and some deepwater plays, suggesting that other options will be more resilient to periods of low oil prices, such as those witnessed during the COVID-19 pandemic.

Figure 20. Cost of supply for remaining global resources.



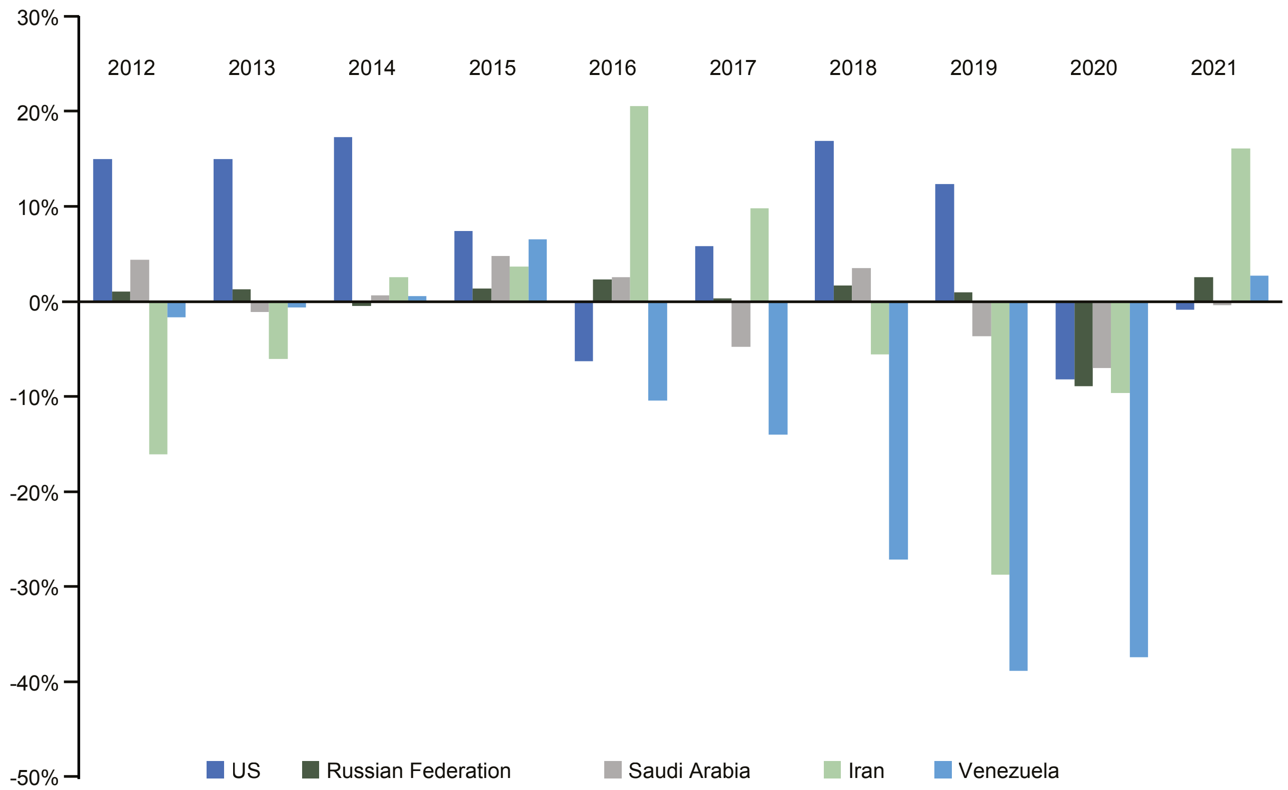
Sources: Rystad Energy, Oilprice.com, 2023.

Section 9: Future of the Tight Oil Industry

Following the collapse of oil prices in 2014 and 2015, the OPEC and some non-OPEC allies agreed to cut their production levels voluntarily. However, Iran and Venezuela were not forced to participate, as they were already suffering from involuntary cuts due to sanctions imposed by the Trump Administration, adversely affecting their oil exports. These sanctions distorted the attractiveness of energy sources from both countries, effectively increasing the appetite for U.S. O&G worldwide. These voluntary and involuntary cuts helped oil prices recover, enabling free-riders in the U.S. tight oil industry to expand their market share in oil production at the expense of OPEC+ members in 2018 and 2019 (Figure 21). These gains have subsequently been reversed.

U.S. shale producers have been the beneficiaries of OPEC policies to stabilize world oil markets. Indeed, the temporary disruption of OPEC+ cohesion in March 2020 had dire consequences for the industry. Following the long uninterrupted, three-year streak of cooperation between the OPEC and some non-OPEC producers to manage outputs and regulate balances in what was called OPEC+, the agreement faced an interruption in March 2020. During those years up until March 2020, the production rates for non-OPEC+ producers increased significantly. First, the OPEC+ cut 1.2 MMb/d in late 2016 (Soldatkin, El Gamal and Lawler 2016) and, then, further cut 2.2 MMb/d in 2019 (Krauss 2019). In March 2020, the OPEC called for further cuts of 1.5 MMb/d because of the ongoing global downturn due to the

Figure 21. Percentage change in oil output for the U.S., Russia, Saudi Arabia, Iran, and Venezuela.



Source: BP Statistical Review, 2022.

COVID-19 pandemic. However, the world witnessed a short end of the alliance on March 6, 2020, during the 8th OPEC and non-OPEC Ministerial Meeting. During that meeting, Russian Energy Minister, Alexander Novak, announced that no agreement had been reached and that production cuts were no longer obligatory as of April 2020 (Astakhova and Golubkova 2020). That statement led oil markets back to being liberalized markets, where survival in such circumstances was dictated by the fittest, with lowest-marginal-cost producers prevailing. Consequently, oil prices plummeted by over 50%, and the volatility level doubled in the Crude Oil Volatility Index (OVX), leading to calls for further cooperation.

Those prices were one of the factors that caused many operators to shut in their tight oil production, as it became uneconomic to produce such oil, and pushed many operators, including major players such as Chevron, to cut their 2020 CapEx. But the OPEC+ fracture of March 2020 did not last long. On April 9, 2020, the OPEC and its allies reached a new deal to stabilize prices, which urged a major round of cuts effective on May 1, 2020 (BBC 2020).

As a result of the new agreement, oil prices showed signs of recovery and increased. As they became profitable, tight oil operators cautiously reopened their shut-in wells and resumed production (Slav 2020). Although the tight oil industry mimics a perfectly competitive market with its sheer number of players, it is still part of a larger industry with influential stakeholders. Nevertheless, by Q4 of 2021, production levels in the Permian Basin reached prepandemic levels, with Eagle Ford and Bakken lagging, despite still growing.

Hence, in this report, we outline three shale revolutions: the first started with rising prices, while the second and third focused on adaptation and capital discipline. Indeed, while the second revolution concentrated on cutting costs, its main objective was to expand market share. During the third revolution, shale producers focused on generating revenues to attract more investments. Some forecasts estimate a shale oil production growth of 3-6 MMb/d within the next seven years, while others argue that tight oil has peaked. Therefore, what is the future of tight oil? To answer this question, we examine the role of tight oil as a swing producer, oil price volatility, and the level of market participation.

1. Tight Oil as a Swing Producer

In early 2015, analysts and forums started discussing the role of tight oil as a swing producer in balancing oil markets. Tight oil production can quickly come online in less than three months, which, in a world with limited spare capacity, can be beneficial to the market in terms of reducing volatility (Balke, Jin and Yucel 2021).

However, with an estimated 3-4 MMb/d in spare capacity from OPEC+ members, tight oil's role is limited. Poor maintenance, low investments, and the shrinking production capacity of some OPEC+ members threaten the group's total spare capacity. Key oil producers in the OPEC, such as Saudi Arabia and the UAE, are expanding their production capacity to around 13 MMb/d by 2025 and 5 MMb/d by 2027, respectively. Thus, in a scenario with no additional spare capacity, shale producers could play the role of expedited suppliers.

Competitive oil prices should also boost the tight oil industry, which counts on a fast reaction alternative. However, this industry guarantees supply only in the presence of competitive oil prices. To summarize, tight oil can be considered a short-term swing alternative in a supply crisis, but its upside potential might not be sufficient for global demand in the long term.

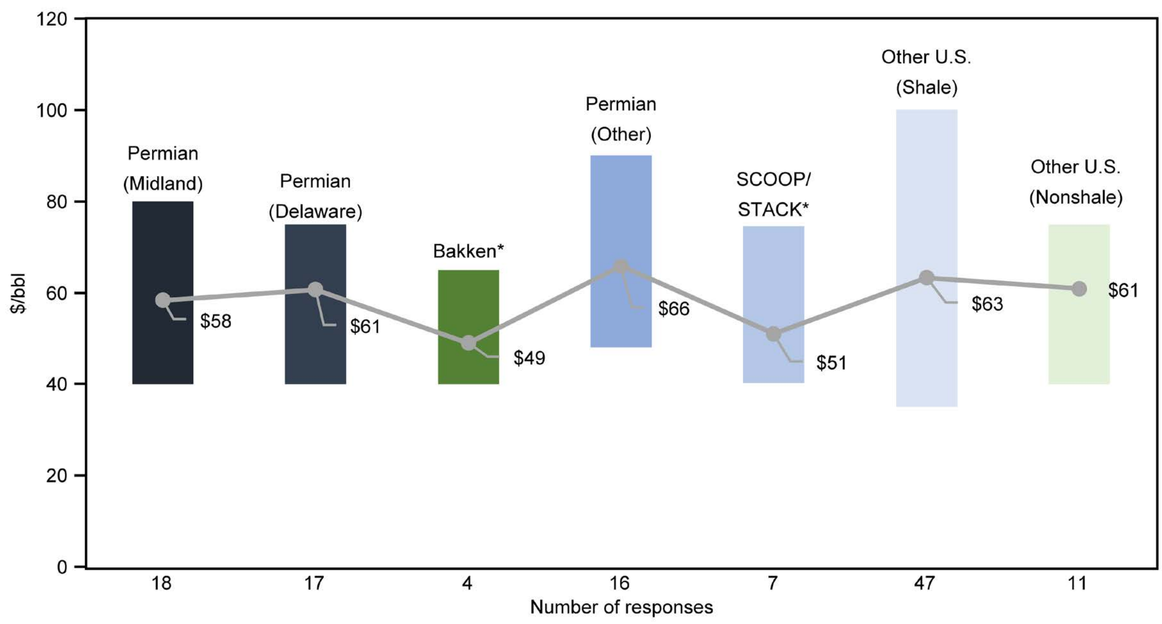
2. Prices above 60 and Shale Reducing Volatility

When it comes to tight oil, prices are essential. Indeed, for shale to thrive, prices should remain above $50/b. It is estimated that 50% of the remaining recoverable resources in the Bakken Basin (8 billion barrels) can be economically developed if the oil price remains near $50/b (See figure 22) (Smith, Estimating the future supply of shale oil: A Bakken case study 2017).

Current geopolitical circumstances are driving oil prices to levels not seen between 2008 and 2023. During the first weeks of March 2022, ICE Brent reached levels close to $140 per barrel, moved by concerns about the Ukrainian crisis and delays in the potential return of Iranian crude oil to the market (Mehta 2022). Experts estimated that high oil prices could stay for a prolonged period of time.

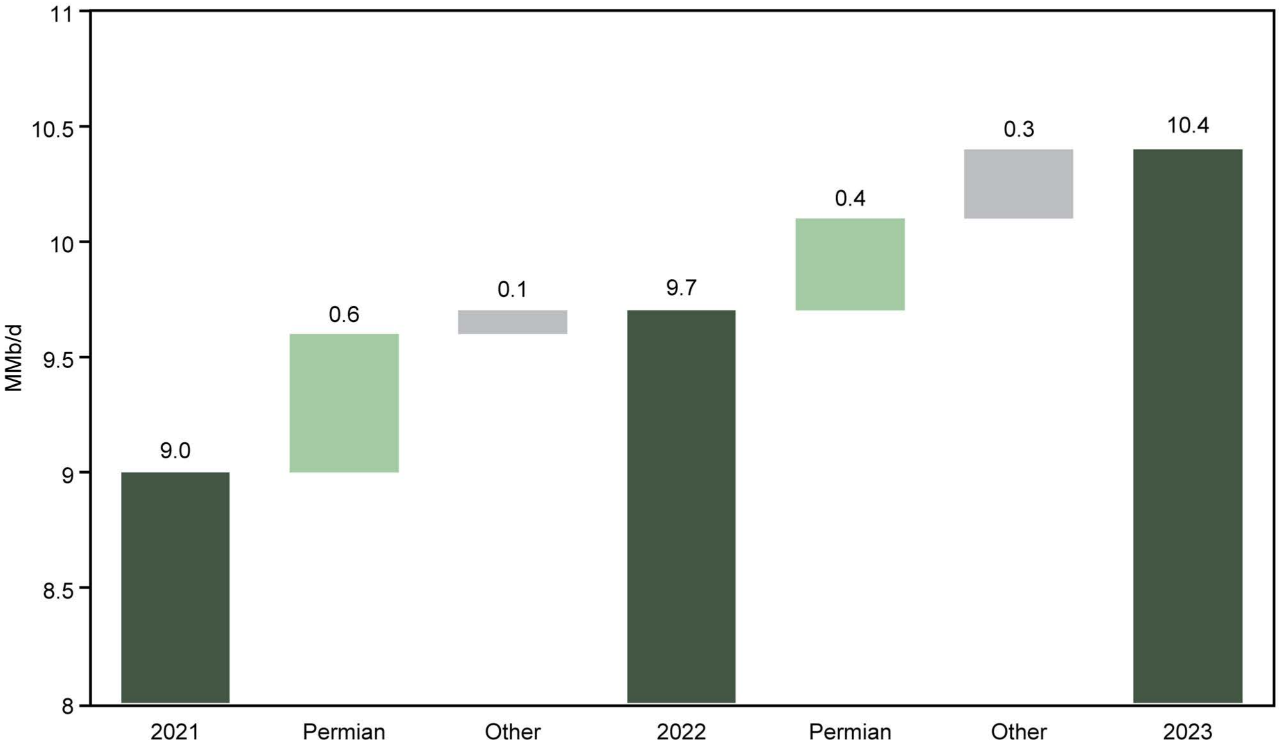
Recognized institutions are reestimating their U.S. crude oil production forecasts based on the abovementioned perspectives. In its Short-Term Energy Outlook (STEO), the EIA estimates that the amount of U.S. crude oil production will be 12.44 MMb/d in 2023, up 560 Kb/d from 2022, and 12.63 MMb/d in 2024, up 190 Kb/d from 2023. Most of this predicted increase will come from new tight oil production in the Permian Basin (EIA, Short Term Energy Outlook (STEO) March 2023). This forecast was laid out in March 2023 under the assumption of a Brent crude price average of $83 per barrel in 2023 and $78 per barrel in 2024 (Figure 23).

Figure 22. Breakeven prices of new wells based on a survey.



*Based on survey results prior to 2023.
Source: Dallas Fed Energy survey, 2023 (Bank of Dallas 2023).

Figure 23. Crude oil production by selected regions in the lower 48 states of the U.S.



Note: Production estimated for 2023.
Source: EIA, February 2022

Moreover, Big Oil firms are changing their perspectives on tight oil developments in the U.S. In February 2022, ExxonMobil's CEO, Darren Woods, informed that his company's production level in the Permian Basin was set to rise by about 25%. In the same line, Chevron aimed to increase 10% of its Permian Basin production, according to Mike Wirth, CEO of the company (Crooks 2022).

3. Need For Better Organization for a Sustainable Future

The tight oil industry has undergone multiple changes and is finally reaching maturity in its third revolution, where capital discipline is geared toward shareholders. In short, shale companies have become fully established, and thus, the need for aggressive unbridled competition no longer exists.

Nevertheless, for this industry to make its mark in the energy mix and become an enabler, tight oil producers need to defend their interests against emerging challenges such as federal land accessibility and climate change concerns and, at the same time, "*coordinate and unify petroleum policies… and ensure the stabilization of oil markets to secure an efficient, economic and regular supply of petroleum to consumers, a steady income to producers and a fair return on capital for those investing in the petroleum industry*" (OPEC, OPEC 2022). Surprisingly, the above text came from the OPEC's mission, as stated in its statute.

There is no doubt that tight oil has become part of the oil ecosystem, showing fierce competition between the OPEC and its partners in terms of market share. COVID-19 has exposed the vulnerability of both parties, with tight oil undoubtedly the weaker of the two. An extensive literature review reveals that the actions taken by the OPEC and its allies have reduced the degree of market volatility. Ironically, the increased volume of tight oil has also contributed to market stabilization. Even though no formal coordination exists, the OPEC and U.S. shale producers are holding a semi-annual meeting in March during CERAWeek to discuss industry concerns (Hampton and Somasekhar 2022) (Kniazhevich, 2023).

However, right on cue, consuming countries suggest that oil producers are not doing enough, asking for a rapid increase in production volume to offset prices (Hunnicutt and Mason 2021). In the U.S., Biden's administration has requested that domestic producers raise output (C. Knight 2021). These calls have been set forth, even after producers asserted that such high oil prices are due to an ESG inspired shortfall in investment in hydrocarbons and unanticipated geopolitical circumstances and not due to a lack of effort from producing companies (Lawler and El Dahan 2022). Additionally, the Inflation Reduction Act (IRA) clause has opened new federal land and offshore blocks for exploration.

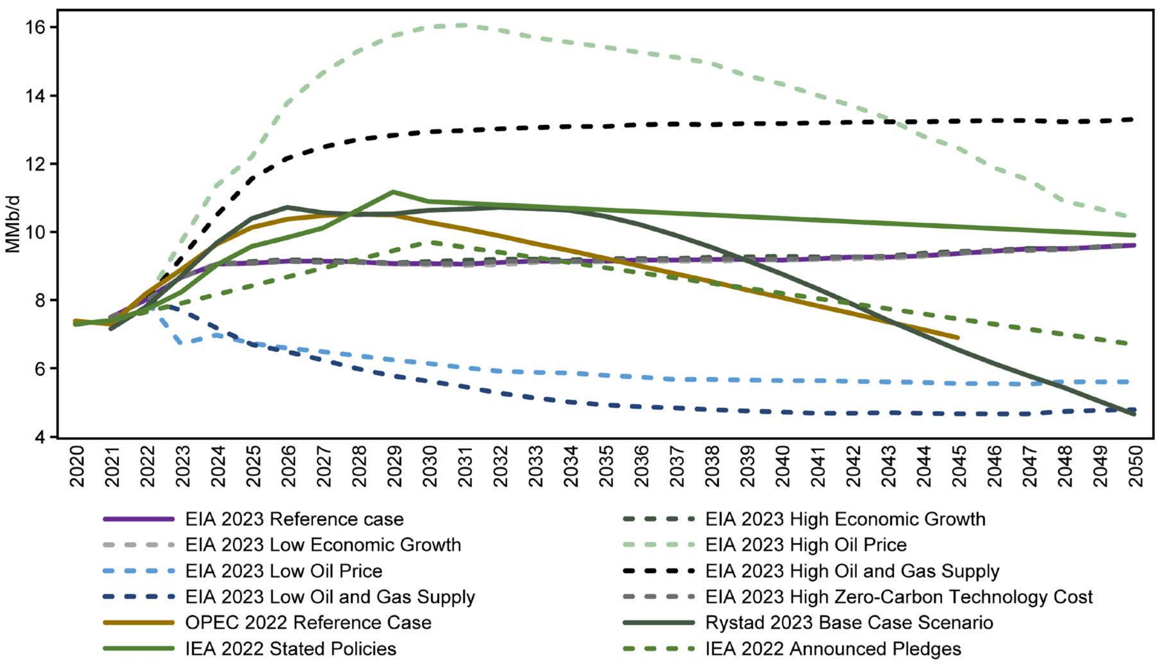
In February 2022, Bruno Jean-Richard Itoua, the OPEC's president, also clarified that no "immediate solution" to high oil prices is possible. At the same time, the oil market was suffering from a lack of investment, cutting the alternatives to rapidly increase production (Reuters 2022). Along the same line, tight oil producers informed their limitations to ramp up production. Some reasons that the tight oil industry was not contributing as expected in 2022 were a shortage of workers and equipment, low-level investment incentives, and a scarcity of sand used in fracking to extract shale oil (Isidore 2022). Many of these same trends and conditions are present at the time of writing (2023).

Section 10: Future of Tight Oil in the Long Term

Tight oil perspectives in the short and medium term are positive (Figure 24). Global oil production has already reached prepandemic levels, and thus, demand will likely rise. However, in the long-term, U.S. tight oil is expected to peak in, at most, eight years.

The 2022 OPEC World Oil Outlook estimates that the U.S.'s tight oil production will peak by 2028 (OPEC, 2022 World Oil Outlook 2045 2022). However, the possibility of achieving this peak sooner than expected has grown due to the current high oil prices, the pressure of consumers to increase production rapidly, and the imperative need of the U.S. to reduce its dependence on oil from some regions due to geopolitical circumstances.

Figure 24. U.S. tight oil supply outlooks (MMb/d).



Source: (OPEC, 2022 World Oil Outlook 2045 2022), (IEA 2022), (EIA, Annual Energy Outlook 2023), and (Rystad, UCube 2023).

Despite the significant amount of economically recoverable tight oil resources, there are several reasons to believe that tight oil production will peak sometime in the next 8 years. Some of these reasons are presented below.

Transition to cleaner production technologies. Despite some studies confirming that greenhouse emissions from tight oil fields are similar to those from conventional production (Ghandi et al., 2015; Brandt et al., 2015), the shale industry produces a significant amount of methane from flaring and venting and wastewater that contaminates aquifers around the production area. Fracking activities are also well known to cause artificial seismic activity that discomforts nearby populations. The above factors are all combined with an average area of 40 acres needed per well involving the continuous operations of truck trips. Altogether, these factors are dissipating the attractiveness of this industry among investors. Big Oil companies are looking for cleaner production options to reach their net-zero targets.

Middle breakeven price. The amount of gas flared due to U.S. fracking activity per basin and land ownership—whether federal, state, private, or Native American land—is given in Appendix B. The tight oil industry highly depends on small independent producers that are nimble players and willing to take risks. However, climate change concerns and the new working preferences of new generations result in a pile of unnecessary measures with which small companies may be unwilling or unable to deal. The IRA of 2022 requires royalties to be assessed on all gas produced or lost by venting, flaring or negligence (IEA, 2022), and beginning in 2024, new O&G companies with wells will have to pay $900 per metric ton of methane reported, increasing to $1500 for 2026 and beyond, according to amendments to the IRA approved in August 2022 (IEA, Inflation Reduction Act 2022: Sec. 60113 and Sec. 50263 on Methane Emissions Reductions 2022). Expensive measures—from implementing environmental, social, and governance (ESG) policies to new strategies necessary to attract a new workforce from a scarce labor supply—are putting small competitors out of business. Additionally, as previously mentioned, Big Oil firms are not interested in small-scale projects with low profit and high risk levels. This third revolution of tight oil could not only be the last revolution but also surprise us with a significant volume increase, depending on future oil prices.

The California Gold Rush effect. As mentioned, the tight oil industry could experience similar effects as those of the California Gold Rush. During the boom of both gold and tight oil, technological developments showed rapid advances. However, as investor interest has waned, the R&D of new emerging technologies has decelerated. Climate change concerns, a lack of interest among investors in the industry, low attractiveness of the industry among Big Oil companies, and the strengthening of ESG policies, among other factors, are halting the research in this field. Thus, whether this field can be motivated by improved future pricing remains to be seen.

Section 11: Scenario Analysis: Boom or Bust?

The future of shale oil is highly uncertain, and there are many potential scenarios for the development of the oil industry. We investigate two possible scenarios: (i) a bust, reflecting the growing international transition to a clean economy and the Biden Plan for a Clean Energy Revolution and Environmental Justice (Biden Harris, 2023), and (ii) a boom, reflecting supply shortages resulting from years of underinvestment in the industry.

1) **Scenario 1: Bust**

   The bust scenario has been designed to consider the following policies proposed by U.S. legislators.

   a. Pausing new O&G leasing on federal onshore land and offshore waters "to the extent consistent with applicable law." The Executive Order on tackling the climate crisis at home promises such a pause (White House, 2021).

   b. Ban on fracking. The U.K. has banned fracking or hydraulic fracturing, and there have been calls for the U.S. to follow suit (Jeong, 2022).

   c. A complete moratorium on investment in the U.S. shale industry. Pressure on investors and Wall Street to scale back their amounts of investments in new oil plays has been mounting over the past few years (McCormick et. al., 2022).

2) **Scenario 2: Boom**

   The boom scenario is designed to investigate the potential implications of a commodity supercycle. Higher commodity prices and the war in Ukraine have inspired a new wave of interest in O&G investment.

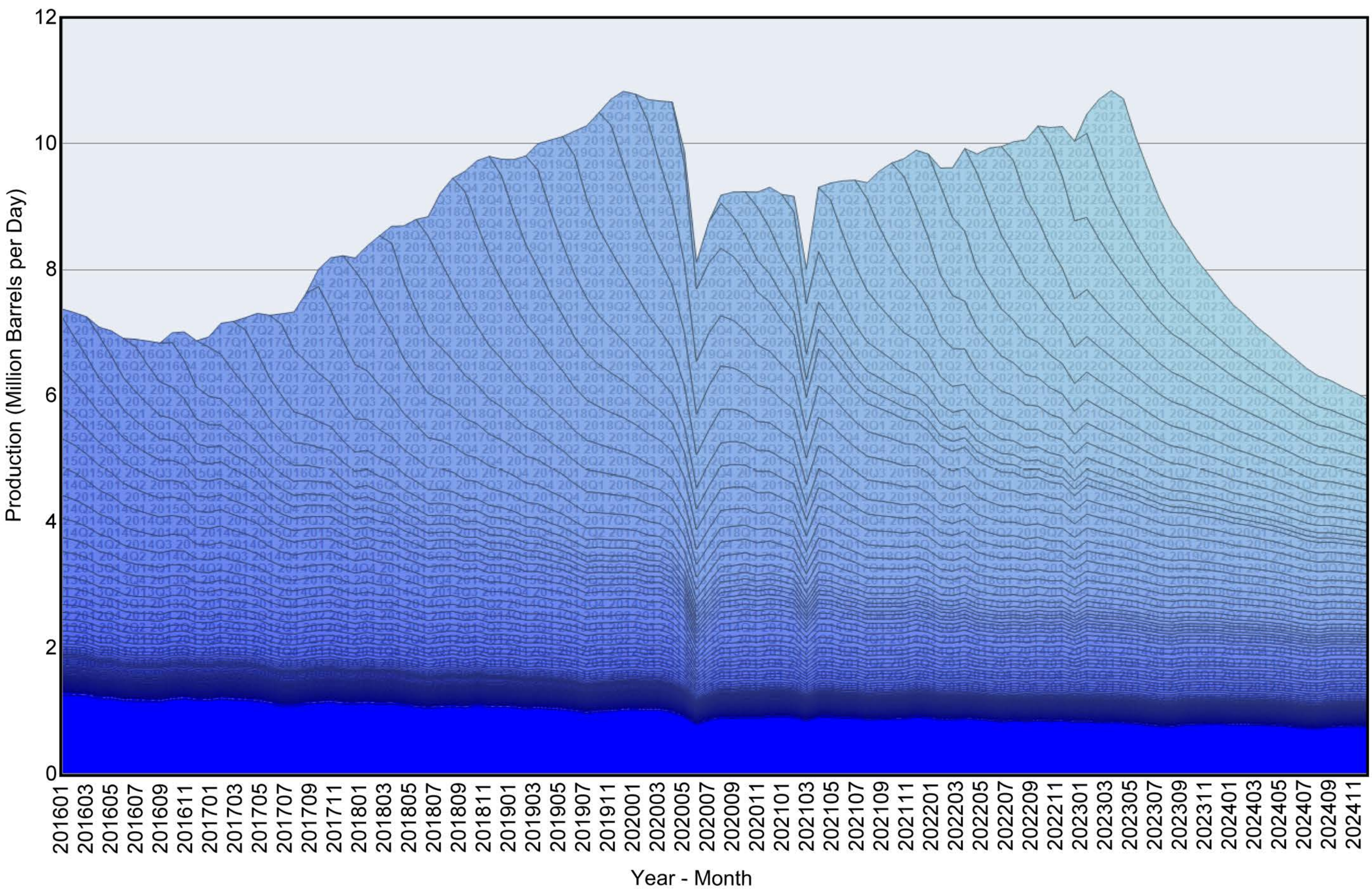
Scenario 1: Bust

Following developments in the U.K., there have also been concerns in the U.S., with proposals ranging from a complete ban on fracking to stopping exports and the construction of all new O&G infrastructure. If passed and fully enforced, any of these proposals would have dire implications for the U.S. oil industry (Figure 25).

Figure 26 illustrates the potential implications of a complete moratorium on new fracking activity in the U.S. To display the bust scenario, we show a simple decline forecast of light oil production from wells from 2023:Q1 to 2024:Q4. The analysis assumes a base case WTI midland price forecast of $79.17 U.S. per barrel in 2023:Q1 (see Appendix A). Given these assumptions, the level of light crude oil production would fall by 4.9 MMb/d, from 10.846 MMB/d in March 2023 to 5.9 MMB/d in December 2024.

The simple decline scenario represents a worst-case scenario and is unlikely to occur. Policy discussions have been heated, and unanticipated events such as the war in Ukraine and the security of supply issues have changed the tone of negotiations. A consensus appears to be forming around a more moderate proposal involving a ban on fracking on federal and Native American

Figure 25. Tight oil production in the U.S. assuming a complete ban on fracking (barrels per day).

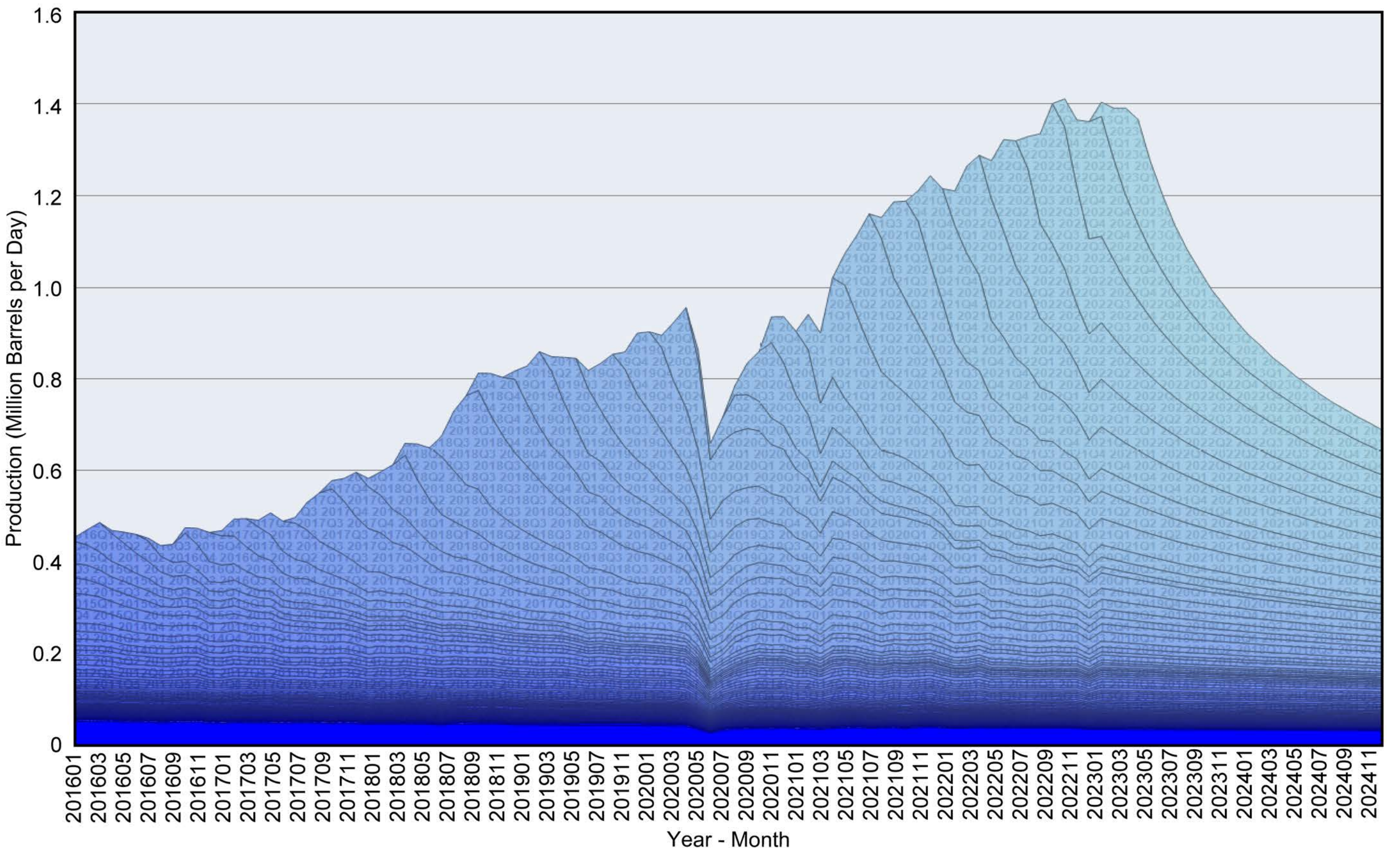


Note: Forecasts start in 2023:Q1
Source: Rystad, KAPSARC, February 2023.

land, but even this might be an overestimate. On January 25, 2021, Native American tribes became exempt from the Biden Administration's 60-day pause and temporary suspension of U.S. O&G leasing and permitting on federal land (Reuters, 2021). Assuming that the ban is implemented on only federal land, light crude oil production will fall by considerably less to 688,000 b/d by December 2024, a 700,000 b/d reduction from the 139,000 b/d reported in March 2023 (see Figure 27).

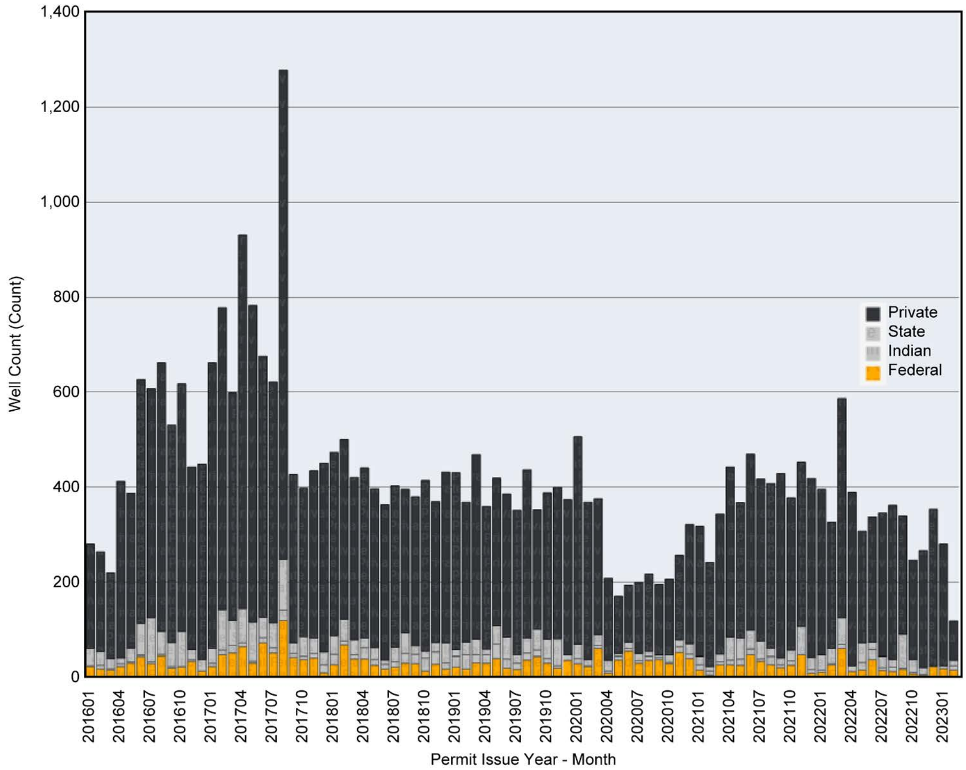
While the simple decline model can depict the direst consequences of a ban on fracking in the U.S., it is likely to be a gross oversimplification. The proposed ban on fracking on federal land is more likely to result in the reallocation of capital to private acreage and a race to secure permits before implementation, a phenomenon that is well underway (see Figure 28) (Brown and Bussewitz, 2021).

Figure 26. Tight oil production on U.S. federal land assuming a ban on fracking on federal land (barrels per day).



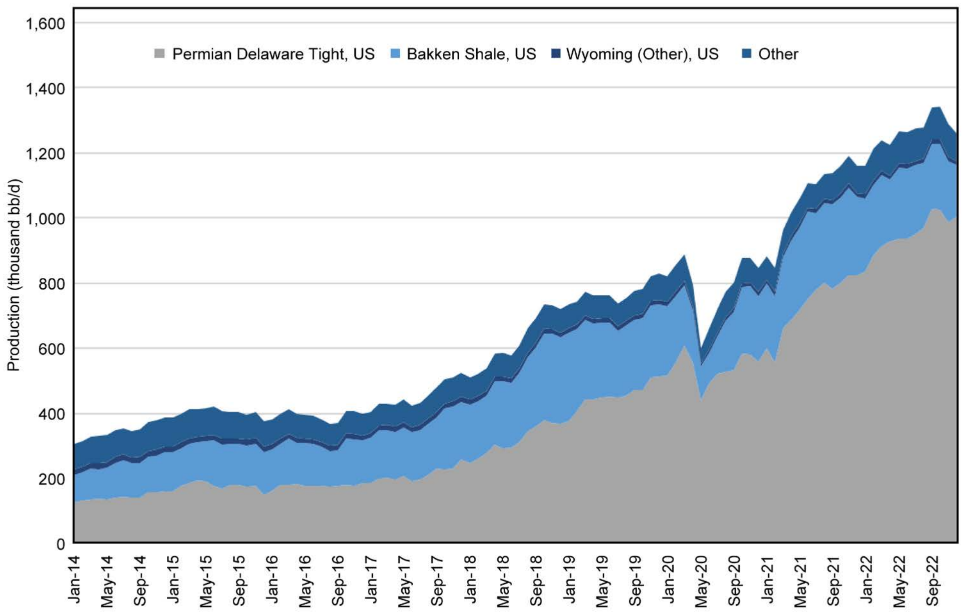
Source: Rystad, KAPSARC, February 2023.

Figure 27. Permits issued on federal, Native American, state, and private land.



Source: Rystad, KAPSARC, February 2023.

Figure 28. Federal acreage oil production by basin.



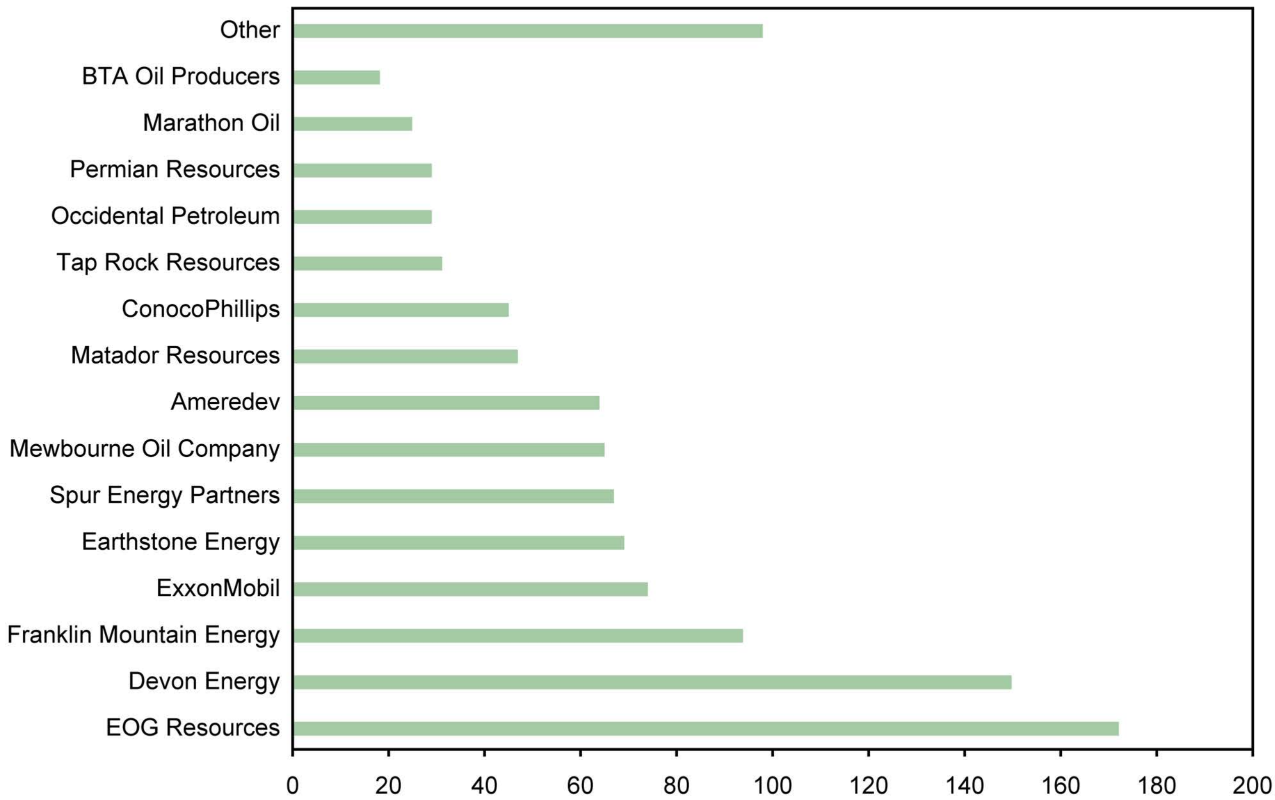
Source: Rystad, KAPSARC February 2023.

The following two points are worthy of mention:

Most drilling takes place on private and state land. As shown in Figure 24, the number of permits issued on private land accounts for approximately 80% of the total permits issued in the U.S. from February 2016 to February 2023. The percentage of permits issued on federal acreage increased from 5.8% in 2016 to 13.7% in 2020, a noteworthy increase in preparation for a Biden victory and his campaign promise to ban fracking on federal land.

A fracking ban on federal land would have the most significant implications for the Delaware Basin, where the share of federal land to total leased acreage averages 60-65% for most operators (see Figure 29) (Rystad, 2019). Remarkably, despite the temporary suspension of U.S. O&G leasing and permitting, operators in the basin have continued to build an inventory of permits. Companies are collecting permits on federal land at a higher rate than such land is being converted into oil wells. From 2018 to 2023, EOG and Devon Energy collected 322 horizontal permits for light oil wells on federal land that have yet to be drilled. Over 1,000 federal acreage permits were issued for oil wells in the Delaware Basin, New Mexico, representing an inventory of around 3.7 years, assuming a 2021 spudded well count (Rystad, 2021).

Figure 29. Approved but not yet drilled federal horizontal permit inventory for oil, Delaware Basin, New Mexico.



Note: The inventory does not include pre-2018 permits or directional or vertical wells.
Source: Rystad, KAPSARC 2023.

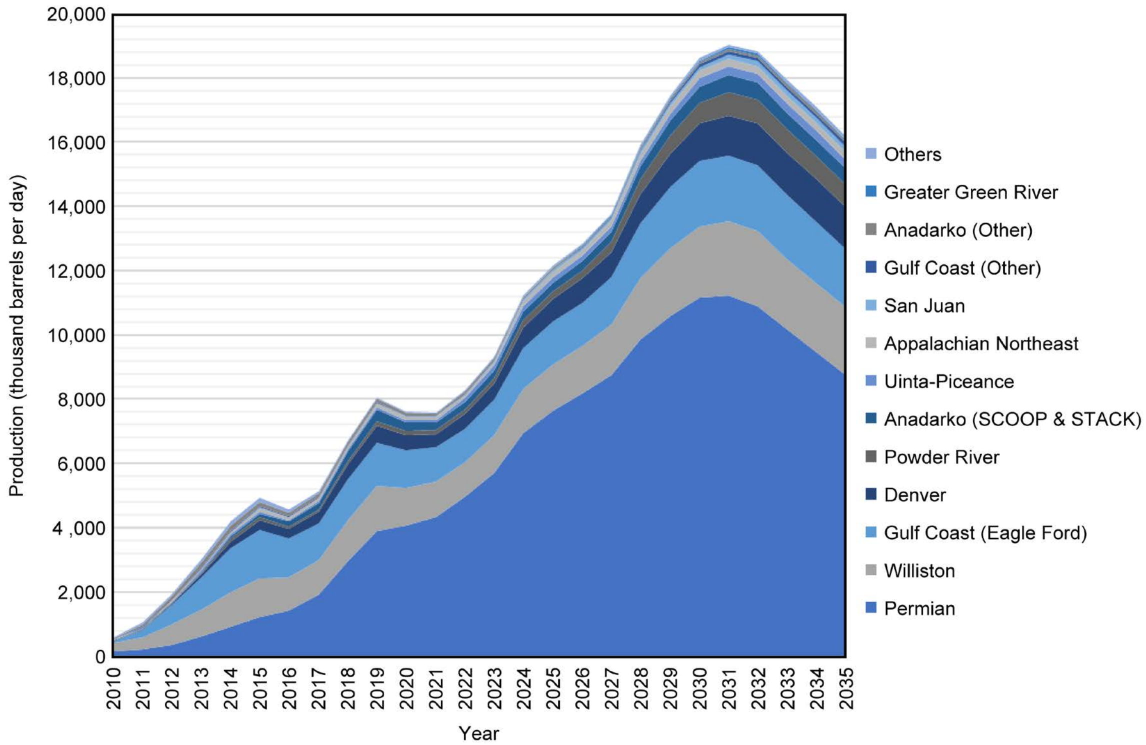
Scenario 2: Boom

Years of underinvestment in the oil industry, sanctions on Russian oil exports, and an increase in post-COVID-19 demand in China are expected to place mounting pressure on oil prices in late 2023 and beyond. According to Jeff Currie at Goldman Sachs, crude oil prices will rise above $100 in 2023 from the current levels of approximately $80.00 per barrel for Brent, reported in February 2023 (Di Paola, 2023). As spare production capacity runs out, supply shortages are expected to become a serious issue by 2024. Extended multiyear periods of boom and bust are known as commodity supercycles and are characterized by prolonged periods of high and low oil prices. We investigate the potential for a supercycle in oil and commodity prices by assuming a flat WTI price of $120 per barrel throughout the forecast period.

Assuming a sustained increase in oil prices and no additional constraints on U.S. crude oil permits and investment, shale oil production has the potential to proliferate, reaching 11.2 MMB/d in 2024 and continuing to rise to a peak level of 19 MMB/d by 2031.

The above two scenarios illustrate a range of potential years of peak shale oil amounts. Between an immediate decline due to a ban on fracking in the U.S. and a crude oil supercycle, we can expect the amounts of shale oil to decline sometime in the next eight years. The exact timeline will be determined by the struggle between environmental concerns and the commodity supercycle, as well as geopolitical security issues. Barring unforeseen circumstances and an unanticipated acceleration in extraction technologies, we can expect a peak this decade based on many forecasts by different analysts.

Figure 30. Tight oil production in the U.S. assuming a commodity supercycle (thousand barrels per day).



Source: Rystad, KAPSARC 2023.

Conclusions

The California Gold Rush and the more recent shale rush show very similar paths, where the inherent value of a product drives scale and innovation in the means of production. The abundant amount of U.S. tight oil resources (estimated at 78.2 billion barrels) saw dramatic improvements in scale and innovation level when prices were high and low, respectively, especially after the 2014 crash.

Independent producers who survived the early days of the market were rewarded for their tenacity and ingenuity to monetize this novel energy source. As knowledge spillovers from these pioneers spread through personnel exchange and acquisitions, larger and more organized outfits entered the sector, including those latecomer IOCs that bought their way in and leveraged economics of scale. The pace of growth has been astonishing, with flexible independents taking larger risks (and rewards) and IOCs relying on diversified portfolios, which enable them to absorb downside shocks and produce returns that are more stable.

According to the EIA, the technically recoverable resources of tight oil in 46 countries were estimated to be around 419 billion barrels as of September 2015, with the share of the U.S. being 18% (U.S. Energy Information Administration 2015). The geology in the U.S. is not unique, but some "uniquely American" aspects lent themselves to both the developments of the California Gold Rush and the shale rush. Property and mineral rights are both held by the landowner instead of the state, and thus, there are far more opportunities for exploration by private firms. The business structure in the U.S. also makes for easy formation, growth, and bankruptcy, creating an environment where risk is tolerated, as opposed to in state-owned enterprises, where failure is not an option. The organic growth, death, and merger of firms have created conditions where best practices and innovation can spread quickly. Outside of the U.S., some of this technology spillover is taking root, as seen in Vaca Muerta in Argentina and the Jafurah Basin in Saudi Arabia (Shabaneh and Al Suwailem 2020), but this is possible only because of explicit state support and a mature local industry.

Finally, historical factors have played a part. In the California Gold Rush, the siren song of gold, a new territory, and an immigrant population with nothing to lose composed a potent mix. During the Shale Rush, the price of oil and energy security concerns helped grow the technology, but the lifting of the ban on U.S. crude oil exports in late 2015 opened the floodgates for investment and increased the strictness of the U.S. terms of oil trade. The tight oil industry could free-ride on the OPEC's production cuts and enjoy much better returns.

U.S. tight oil is now exploitable, and exogenous factors, such as demand and supply shocks, may choke, but not put a complete end to, investments in exploration and production. As such, tight oil is here to stay and will remain an integral part of the O&G industry. The California Gold Rush did not end due to gold mines running out of gold deposits but rather due to mining becoming more specialized, which might be the case for the tight oil industry moving forward. However, organizing shale producers under a certain banner will benefit not only shale producers but also global markets by reducing volatility and allowing for longer and more sustainable growth. While the California Gold Rush is a singular and unrivaled event in U.S. history, the shale revolution has undeniable parallels.

The present shale rush should note the following last lesson from the California Gold Rush:

> *When the Gold Rush ended, boomtowns turned into ghost towns overnight.*

Policy-makers need to be wary of the boom-and-bust cycle of shale. Short-term profits and jobs are alluring, but there are problems on the horizon concerning environmental initiatives, bans on fracking, methane leakage, and the transition to renewables. Efforts to address these problems are underway, with sustainability measures to enhance the economic efficiency of tight oil. These measures include the reuse of water resources and flared gas management, both of which reduce the CapEx and operating expenses (OPEX) of project operators. The flared gas from the Permian Basin alone has the potential to ultimately serve the gas needs of the seven largest cities in Texas (Dickson et, al., 2019).

Many analysts are calling for a supercycle in commodities and the price of Brent rising to levels over $100 per barrel in 2024 (Tan, 2023). Another boom period for U.S. shale cannot be ruled out, but there are alternatives in the market that could displace such an effect. Middle Eastern onshore assets are very inexpensive, deepwater projects are capital intensive but very productive, and the risk of shale development has dropped to the point that non-U.S. resources are back on the table. There has been a flurry of consolidation this year, with ExxonMobil's purchase of Pioneer Natural Resources and the Chevron-Hess announcement - accompanied by rumors of Chesapeake-Southwestern, and Devon-Marathon - all promising to cut costs, increase production and optimize the value of U.S. shale reserves (Rystad, 2023).

However, there is always hope; harsh weather and waterflows in the Sierras have exposed new gold deposits in California, and the rush is on (Sunset, 2023).

Endnotes

[1] Shale and tight oil are used interchangeably. The U.S. Energy Information Administration (EIA) describes gas found in shale formation as shale gas and oil found in shale layers as tight oil.

[2] Hydraulic fracturing or fracking is a process that involves injecting water, sand, and chemicals under high pressure into oil- or gas-bearing formations to create new fractures in the rock that enable hydrocarbons to be extracted (US Geological Survey 2020).

[3] Tight oil is composed of light, sweet crude like Nigeria's Bonny light crude.

[4] Multiwell pad drilling, where multiple wells are drilled from a single site, allows for significant surface cost reductions.

[5] "The U.S. Internal Revenue Code section 613A(d) defines an independent producer as a producer who does not have more than $5 million in retail sales of oil and gas in a year or who does not refine more than an average of 75,000 barrels per day of crude oil during a given year. There are about 9,000 independent oil and natural gas producers in the United States. These companies operate in 33 states and the offshore and employ an average of just 12 people" (IPAA 2022).

[6] Well completion is the process of transforming a drilled well into a producing well.

[7] Proppants are sand particles injected along with fracking fluids to hold the fractures after creating them using induced pressure (Schlumberger 2020).

[8] Sweet spots are areas within shale plays that have the best or potential level of production (Schlumberger 2020).

[9] Multiwell pad drilling, where multiple wells are drilled from a single site, allows for significant surface cost reductions.

[10] Independents are O&G companies that are engaged solely in the exploration and production segments of hydrocarbons. Unlike IOCs such as Chevron, these companies do not engage in the processing, refining, marketing, and selling of hydrocarbons to end users (DiLallo 2014). The median size of an independent is 12 full-time employees (Independent Petroleum Association of America 2013).

[11] IOCs are privately owned and vertically integrated in a sense that they are involved in all aspects of the exploration, development, processing, marketing, and selling of hydrocarbons (McKinsey & Company 2020).

[12] IOCs are privately owned and vertically integrated in a sense that they are involved in all aspects of the exploration, development, processing, marketing, and selling of hydrocarbons (McKinsey & Company 2020).

[13] A low-profit environment in the oil industry is not necessarily equal to a low-profit environment in other industries. However, Big Oil companies are not very active in tight oil activities unless the profit expectations surpass certain levels.

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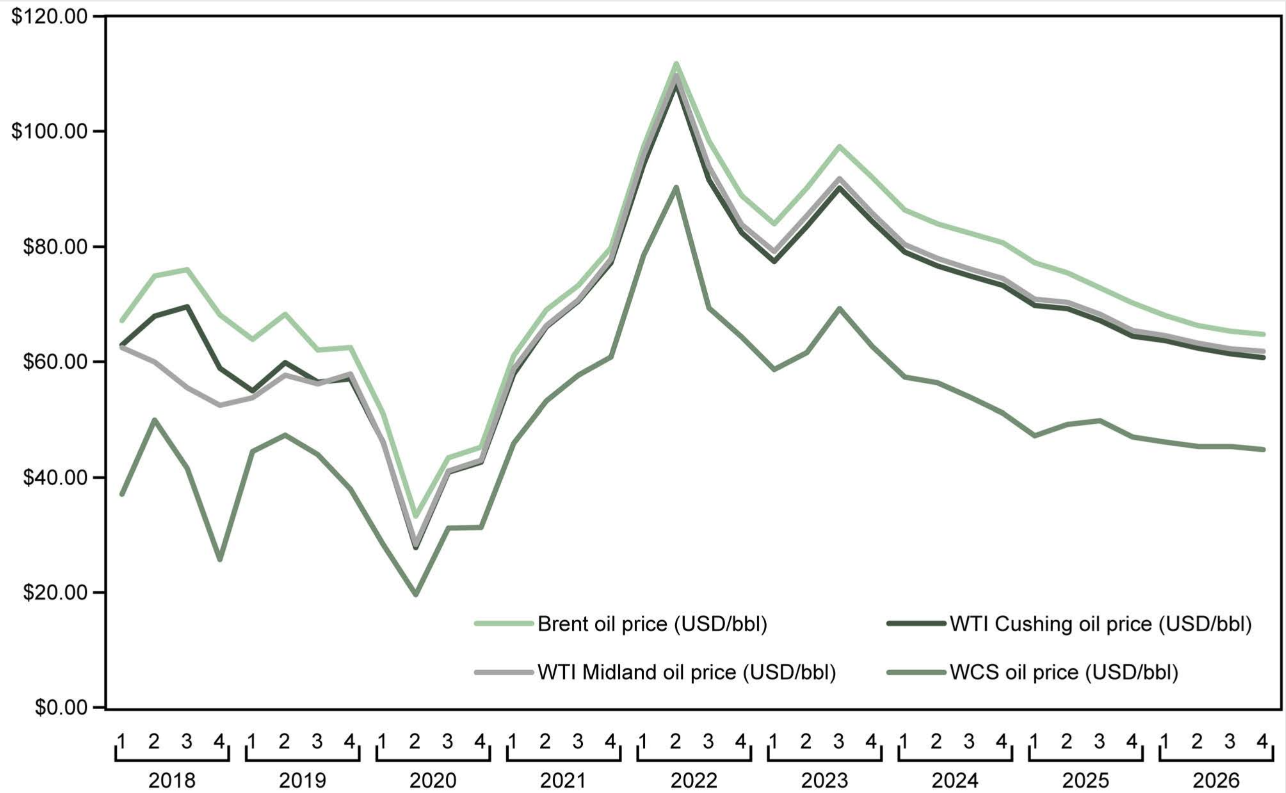
Appendix A

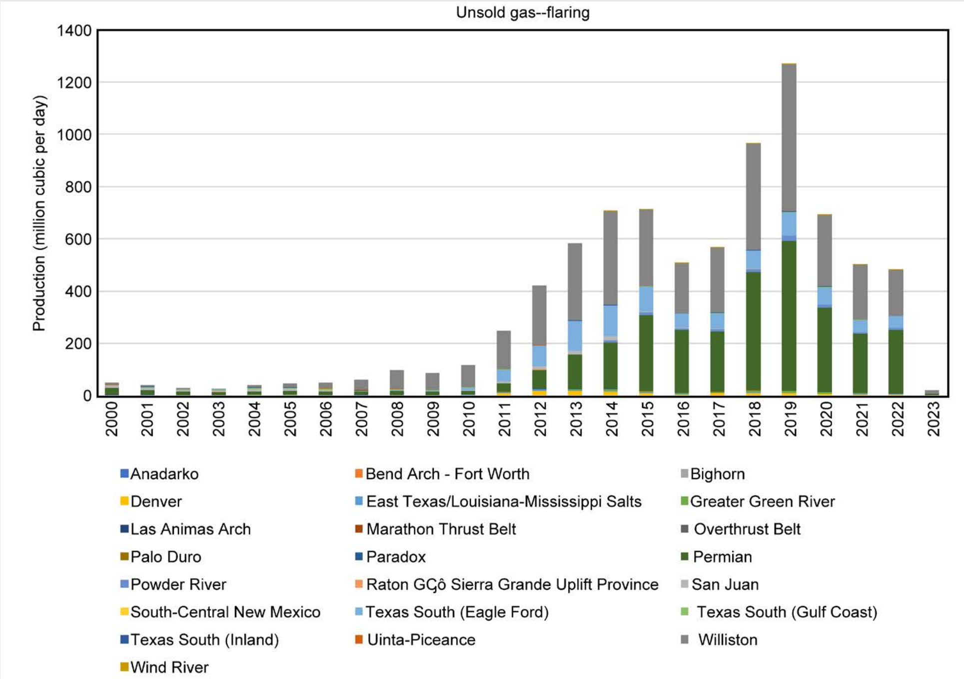
Figure A.1. Reference case: Crude oil price assumptions.



Source: Rystad, KAPSARC 2023.

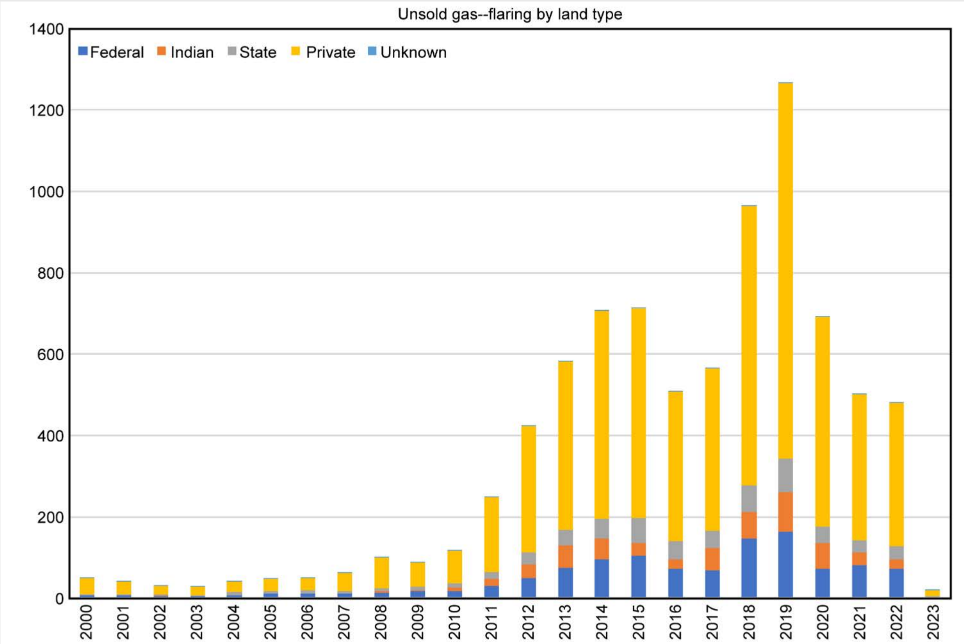
Appendix B

Figure B.1. Shale gas flaring by basin.



Note: This analysis assumes base case price assumptions.
Source: Rystad, KAPSARC 2023.

Figure B.2. Shale gas flaring by land type.



Note: This analysis assumes base case price assumptions.
Source: Rystad, KAPSARC 2023.

Notes

Notes

About the Authors

Majed Alsuwailem

Majed is a Fellow at KAPSARC with a focus on energy security, geopolitics, and hydrocarbon laws and regulations. He has more than 15 years of experience in the oil and gas industry in the fields of simulation and modeling, asset management, reserves estimation, oil field development, disruptive technologies, and business planning, gained at Chevron and Saudi Aramco.

Majed holds a B.S. degree in petroleum engineering from the University of Tulsa in the United States, along with two M.S. degrees in petroleum engineering and reservoir geosciences and engineering, respectively, from Texas A&M University and the Institut Francais du Petrole (IFP School). In 2021, Majed earned his Master of Science degree in public economics and policy from Purdue University.

Colin Ward

Mr. Ward started in the oil industry doing seismic work during high school in Argentina. In the intervening 20+ years, he earned degrees in Philosophy, Engineering, and an MBA, designed refineries and petchem facilities, became a cost consultant and development planner, and is now focused on market forecasting and environmental impacts. He is excited to see what the next 20 years have in store.

Jennifer Considine

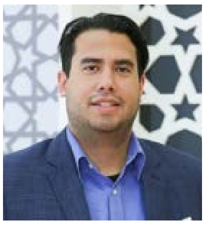
Dr. Jennifer Considine is a visiting researcher at KAPSARC and a senior research fellow at the Centre for Energy, Petroleum and Mineral Law and Policy (CEPMLP) in Dundee, Scotland. Previously, she led a number of projects involving options pricing, real options valuations of physical assets, including electricity generation facilities, storage companies, natural gas pipelines, and contracts, risk management and hedging techniques, and trading strategies for a variety of commodities, including natural gas, electricity, and crude oil.

Dr. Considine has worked with a number of international energy companies, including Ecopetrol, TransCanada Pipelines, Westcoast Energy, Coastal Corporation, Duke Energy, and ANR Pipeline Company. She is currently : (i) an Editorial Board Member of The Global Commodities Applied Research Digest, J.P. Morgan Center for Commodities & Energy Management, and (iii) an Editorial Board Member Commodity Insights Digest Bayes Business School - City, University of London (U.K.), and (iii) Honorary Oil and Commodities Correspondent, Intelligence Forums. Dr. Considine is a former member of the Board of Directors for Canada Post and a founding member of a number of initiatives to promote Scottish-Canadian relations, including the Canadian Friends of Scotland.

Julio Arboleda

Mr. Arboleda is a seasoned economist and civil engineer, boasting over two decades of expertise in the energy sector. Currently, he serves as an oil market research fellow at KAPSARC. Prior to this role, he held positions as a senior energy consultant within various international energy organizations. Notably, he played a crucial role in shaping the World Oil Outlook (WOO) at OPEC for several years. His professional experience encompasses energy policy, data analysis for international organizations, governmental advisory services, and the management of energy projects.

Mr. Arboleda is deeply passionate about sustainable energy and project management, both of which are underpinned by his post-graduate studies at institutions in North America and Europe. Over the last two years, Mr. Arboleda has spearheaded the global investment monitoring efforts, and his team is currently engaged in developing a model for forecasting investment requirements within the oil and gas industry.



Hamid Al Sadoon

Hamid leads KAPSARC's Oil Market Outlook (KOMO) quarterly reports. He focuses on all aspects related to short- and long-term energy forecasting, covering a wide array of topics, including demand, prices, inventories, etc. Prior to joining KAPSARC, he worked for three years in corporate planning at Saudi Aramco as an analyst. Between 2012-2016, Hamid was a negotiator for the Saudi climate change team at different United Nations bodies, covering various topics under the Paris Agreement, such as adaptation, transportation, etc. He negotiated on behalf of the Kingdom at the UNFCCC, Montreal Protocol, UNEP, IPCC, and ICAO, among others.

About the Project

The Future of Shale Development project aims to assess the impacts of U.S. shale oil and gas on supply and demand balances. This project also examines the performance of U.S. shale production and highlights the challenges that hinder shale oil and gas growth. These challenges include technologies, environmental policies, and access to capital.

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