# The Future of Oil and Gas

## How Technology is Driving Innovation in Exploration and Production

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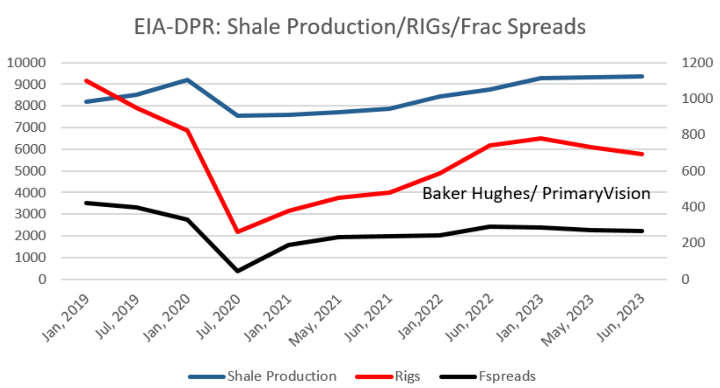
The last decade has seen, arguably, the most significant changes in the upstream oil and gas industry in modern times. A decade of unbridled expansion that began in the early 2000s came crashing to a halt in mid-2014 and was followed by a near decade of retrenchment, bankruptcies, and industry consolidation. Despite a resurgence from the pandemic lows of 2020, the industry has not yet returned to the levels-in terms of rig activity of that earlier era, nor is it likely to do so.

In the era in which the industry now operates, the paradigm has shifted away from ramping drilling higher in higher oil price periods to maximize production, as was done before 2014. Now growth capital is constrained to levels that will sustain the current production level, or deliver single-digit increases, in favor of balance sheet improvement and shareholder returns. What is truly amazing is that during this era, the production of oil and gas has nearly regained pre-pandemic levels.




How has this been possible? There are two reasons primarily. The first is oil companies began to draw down their inventories of Drilled but Uncompleted wells-DUCs, from over 8,500 in 2019 to just over 4,800 today. The second, and the factor we will focus on primarily in this report, is technology.

Technology has transformed the way we extract hydrocarbons from petroleum reservoirs in a startlingly short time. Beginning from the industry reset that occurred from the oil price crash of 2014, operators have used technology to: better understand their reservoirs, learn how to more efficiently drain, and drive down capital costs, such that many fields are economic at levels below $40.00 per barrel. A steep drop from a few years ago.

## Reservoir Development and Machine Learning

One of the challenges that always bedeviled the petroleum industry was the sheer volume of data that had to be processed to make a decision. Questions like where to drill, how to most efficiently and completely drain the reservoir, and many others hounded petroleum professionals into the 1970s, with the final answer often being, “Let’s go drill and see what we find.” Hardly a basis to spend millions of dollars and the success rate for new wells was commensurately low.

In the 1970s Rate Transient Analysis-RTA began to provide a basis for more sophisticated analysis of flowing well data, assisted by the rapid rise of computing power in the 1980s. This methodology rapidly became a sub-discipline of Reservoir Engineering with a core group of commercial software applications supporting it. An example of this would be Schlumberger's Petrel digital platform, with a full suite of applications to assist engineers in understanding not only optimal flow characteristics of the reservoir, but Reservoir Modeling, Geomechanics, and Drilling Applications. The industry had come a long way from "Let's drill..," but as the shale era began, it was found models and algorithms that had worked well in conventional reservoirs had limited application to unconventionals.

Trent Jacobs, writing in the Journal of Petroleum Technology-JPT, in an article titled, Reservoir Software Developer: RTA Had Its Day, Hybrid Modeling Now the Way noted:

*"Rate transient analysis (RTA) is defined as the science of analyzing and forecasting production data. But in its application to ultratight reservoirs, it's also been likened to an art form. There is no unified approach for reservoir engineers to follow in RTA, and as such, its solutions are nonunique. In other words, the accuracy of the analysis lies in the eye of the beholder. Another camp holds that the analysis method originally designed in the 1970s for forecasting in conventional reservoirs has reached its useful end in unconventional reservoirs."*

Machine Learning has stepped into the gap in shale plays. In an interview for this article, Ted Cross, Director of Product Management for Novi Labs, an oil and gas data analytics consultancy, laid out the role this revolutionary new technology is playing in helping operators to maximize production from shale reservoirs in an interview for this report.

"First, physical modeling tools have proven inadequate at describing shale reservoirs due to the complexity of their geology and the fabric of the rock. The fracture networks initiated and the proppant placement are difficult to describe with the physical modeling tools taken from conventional. You can get in the ballpark with them, but these tools are just not suited for describing and predicting outcomes in unconventional wells.

Then there is the sheer quantity of the data being generated. Some fields, like the Eagle Ford, have as many as 30,000 wells. The use of Machine Learning statistical algorithms, which require large amounts of data to present an accurate picture, enables petroleum professionals to make more informed decisions about the reservoir. Finally, another enabler for the use of advanced technology in reservoir assessment is the big data analytics-cloud computing and AI algorithms that have been created by petroleum professionals to tackle these problems."

One of the ways the use of Machine Learning is contributing to better outcomes in oil and gas production is improved accuracy in forecasting production from a well. Ted commented that improvements of 30-50% had been gained by employing Machine Learning over previous methods by individual operators, noting that "cultural (individual) biases could lead to under or over-forecasting production from a well." This improved accuracy can play a role in optimizing completion styles and costs.

Another use case being actively employed by shale operators is evaluating reservoir development plans to develop lower-tier acreage. Ted noted there is a realization among operators that "what works for your Tier I rock may not work for Tier II rock."

## Drilling

In some respects drilling oil wells hasn't changed much in the last 100 years. The rigs look pretty much the same. The high-level drilling and completion processes-pipe, mud, cement, and logging, are much the same as when they were developed in the early era of oil exploration. But when you look more closely, you find all of these technologies are in a state of development that could scarcely be imagined even a few years ago.

This is important because the wells now being drilled are up to ~50% longer than wells drilled in the twenty-teens. It's now becoming common to drill 15,000' lateral sections in some reservoirs. Additionally, the stacked reservoirs in the Permian make wells called "Multi-laterals" drilled from concrete pads, with a "Fish-Bone" pattern possible. They also enable the use of "Walking rigs" that can be moved a few feet to the next slot without being broken down. How did we get here?

Necessity has been called the "Mother of Invention," and the nascent shale drilling industry was dealt an intentional, near-death blow from OPEC in 2014. The cartel, seeking to reclaim the role of Swing Producer, opened the taps in the middle of that year and flooded the market. This had the effect of making U.S shale production, much of which had breakeven costs above $60 per barrel, uneconomic as prices slid into the $40's.

Once the basic format of drilling horizontally and then fracturing the rock had been settled, production had grown by adding rigs and frac crews. In February of 2015, shale production peaked and began a decline that lasted until mid-2016, taking a million BOPD offline. The gauntlet had been thrown down to the U.S. shale drillers-cut costs or die. How the industry overcame this setback and drove production to new highs in 2020 is a story of technology coming to the rescue.

The chart below, with data compiled from the EIA Drilling Productivity Report-DPR, shows just how efficient we have become. In the most active basin, the Permian, in 2023, 342 rigs delivered a new oil average of 1107 BOEPD. In 2014, 568 rigs delivered just 247 BOEPD of new production. That's nearly a 4-fold increase in just eight years.

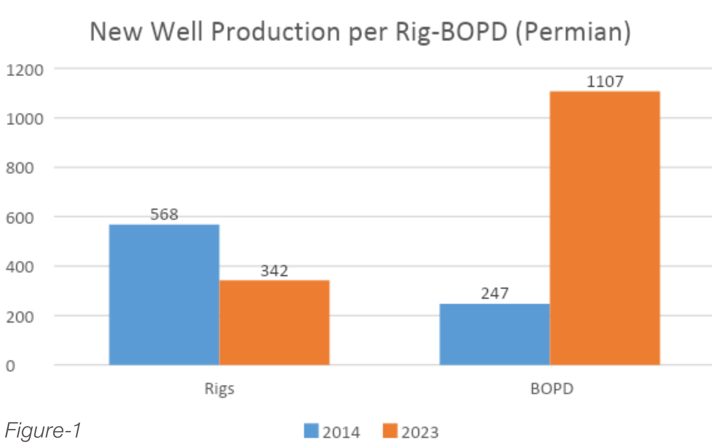



*Figure-1*

When I first got into the business, I was introduced to the "Days vs Depth" chart. The goal here is to establish the minimum, or Technical Limit, time and then to cost out an AFE estimate that actual performance can be measured against. The problem shale had was that the actual time was taking too long. This was due to a couple of things primarily.

First, drilling tool errors caused unnecessary bit trips. Anytime you are "tripping" pipe (running pipe into the hole or pulling it out of the hole), it is recorded as flat time on the days vs depth chart and adds costs in the form of rig time, third party time, and lost production.

These days "drill bits" are attached to amazingly complex devices known as, Measurement While Drilling-MWD assemblies form the Bottom Hole Assembly-BHA and perform the primary function of locating the BHA in the reservoir. These BHAs use telemetry to send a real-time signal to the surface where petro-technical professionals monitor its performance.

One of the things that had to improve was the reliability of these MWD tools as the complexity of the wells being drilled increased. Here again, AI-Machine Learning has played a role in the increased sophistication of MWD tools, leading to fewer failures resulting in unnecessary bit trips and improving well economics. But, it goes further than that, as highlighted in a recent JPT article.

David Gutierrez, writing in the JPT in an article titled, Space-Age Directional Drilling Improves Efficiency, Economics, commented on the use of modern drilling technology in improving performance and economics-

*"The foundation of the recommendation is built on real-time surface and downhole drilling data, the interaction between the BHA and the formation, and continuously updated trajectory estimates. The proprietary software system uses advanced artificial intelligence (AI) algorithms to refine the calculation of rotational tendencies and motor yield in real time to allow for reliable forward projections and optimized slide scheduling through each well section."*

The next major step-change was the advent of "Pad-Drilling," and the Super-Spec walking rigs that enabled simultaneous operations-simops, like "Zipper-Fracs." An article carried in JPT in 2014 noted-

"This shaves days off the time it takes to complete a multi-well pad. Many companies in south Texas are now using the completion method on almost every new pad site they drill into, saving tens of millions of dollars per year while accelerating the development of their well inventories."

Pad drilling began as a way to improve costly rig-up, rig-down times between wells, as noted in this EIA Bulletin. Pad drilling also enabled optimization in well spacing that was the outgrowth of "parent," "child" well interactions, called "frac-hits," that were deemed to interfere with production and maximum recovery. In fully developing shale reservoirs, it was found that planning for later child wells and thinking of the reservoir as a "cube," would promote better recoveries overall.

Walking rigs, also known as Super-Spec, capitalized on the firm surface and adjacency of nearby wells to avoid the traditional moving process that can take several days to accomplish. Less time to move equates to more rigs available to drill, as noted in a Reuters article in 2015, and has helped the industry achieve the four-fold increase in new oil per rig illustrated in Figure-1.

## Automation and Robotics in drilling

Drilling oil wells is a mechanical process that, until recently, had not changed a lot. Men in appropriate safety gear laid out individual joints of pipe in front of the rig's "V" door, where it was put into position to be hoisted vertically above the drill floor by a winch and made-up into a "stand"-2, 3 joints. Working sixty to one hundred feet above the drill floor, the Derrickman, and with the assistance of the Floorhands, racked back each stand in preparation for drilling activity to begin. A laborious and dangerous task that, in modern times, cried out for improvement.

Automation and Advanced Robotics have begun to displace humans on the drill floor. Writing in the December 1st, 2021 issue of JPT, in an article entitled, A Robot Takes Over The Drill Floor, author Steven Rassenfoss discusses the implementation of AI-assisted automation and robotics to create an "automated drilling floor," in a ground-breaking Nabors Industries rig-PaceR801, drilling on an ExxonMobil pad-site in the Permian basin. It only has one human, safely located in the Driller's cabin.

"Delivering on the promise of faster, better drilling requires a series of precisely executed steps with a minimum of time lost between movements. A rig floor video would show the robot reaching over to pick up the next piece of hardware—normally a 45-ft segment of pipe that had been measured and its threads doped previously by the system. The arm then moves it over the well center and holds it vertically in place while other machines recognize the thread pattern and spin the pipe to connect it with the right level of torque. Then another application takes over to lower the drillstring to the bottom and resume drilling according to ExxonMobil's specifications."

The article goes on to note that this prototype rig with the automated drill floor is being increasingly sought by new clients wanting to streamline and speed up the drilling process and remove humans from dangerous occupations.

This automation process is another step along the way toward improving the good economics that adds up to more wells being drilled without an increase in capex. Is this the Rig of the Future? According to the author, there is still a way to go, as interoperability between third-party systems is the next threshold to cross.

John Willis, vice president for drilling and completions for onshore and carbon sequestration for Occidental, in his keynote address at the recent IADC Advanced Rig Technology Conference (ART) covered by the IADC Drilling Contractor, commented that  "When we go to try to buy automation, it's really hard to get," Willis said "We're largely limited to what's available from individual drilling contractors. It's very difficult, if not impossible, to take something from another third party and add that to a rig. And none of our rigs have what we would consider to be a full system of automation today."

Clearly, the industry has made substantial progress and still has miles to go in delivering the level of automation desired by the industry.

## Drilling fluids

Drilling fluids play a crucial role in the industry's ability to drill the horizontal wells that are necessary to provide the well bore for fracking. In a conversation with Matt Offenbacher, Director of Technology at AES Drilling Fluids, the challenges being put to drilling fluids suppliers by the shale industry were highlighted.

"Operators are definitely coming to us for new solutions for rate of penetration, hole-stability, torque reduction, and a minimized environmental footprint," Offenbacher noted. "And, of course, they want all of this at the least possible cost."

To meet these criteria a new suite of drilling fluids is being offered to drillers. Offenbacher mentioned one such offering from his firm, AQUA-FLEX that hit these targets through performance additive selection to address the risks when and when they occur "We have this big data set that helps us prequalify a fluid like AQUA-FLEX for a particular field. If history tells us that it's likely we are going to experience torque issues beyond a certain horizontal length, or if penetration rate or cost are the big drivers, for example, then a system like this-AQUA-FLEX, can tick most of the boxes."

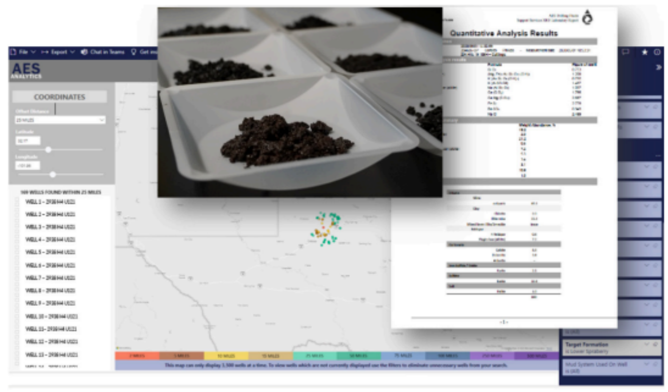


**Figure 1.** *AES ANALYTICS map tool feature allows users to quickly filter data to a target formation, where dozens of XRD/mineralogy lab results can provide further understanding of location-specific drilling risks.*

*Picture: Courtesy of AES Drilling Fluids*

While drilling fluids are the least costly of all the components of new well construction, they fill a critical role in the industry's desire to drill farther with less direct cost.

## Completions

Completions account for over half the cost of a shale well, so there is a lot of room to realize savings. At a high level, shale completions consist of setting plugs in the casing to establish a "Stage," perforating through the casing into the rock to provide a pathway for water and sand to be pumped in the next phase, and then continuing this plug, perf and pump repetition until all the stages have been installed.

Ron Gusek, President of Liberty Energy, a major provider of pumping services to the fracturing industry, commented for this Report that some of the steps that have been taken to realize savings have come from improvements in completion optimization and execution.

"If you take a typical horizontal, say 10,000' as of 2022, and divide it into stages, you have 50, 200' stages. Over the last 5-7 years, we have progressed from shooting holes in the middle of that section to install the frac, leaving ~100 feet of rock on either side unstimulated, to breaking each stage up and perforating in 15’ or 20’ intervals to create more entry points, but shooting fewer holes per entry point. The goal is to ensure that when we pump water, a fracture grows from each and every one of those entry points.

*Photo: courtesy Liberty Energy*

Gusek went on to note, “There are a couple of benefits from doing this. First, we get accelerated recovery from the well. Perhaps that’s 65-75% of the benefit, having the oil come at us faster, and the rest is increased total recovery-EUR from the well.

Then there is the application of AI technology to the surface equipment, pumps, valves, sensors and the like. Gusek continued-

“We continue to get more and more efficient, particularly in terms of pumping time. It used to be that if you averaged across our fleet, we managed 45% of a day pumping. Now we often hit 65-70%, even counting location moves. How do we get there?

Predictive analytics. Everything we can instrument is instrumented. As a result, we know vastly more about how our equipment is performing in real-time than we used to. Over time we’ve compiled this massive data set that if a component like an engine is going to experience a catastrophic failure, we can see it coming and do something before it happens. What all of that means is better equipment uptime and faster reactions for our mechanics and techs who are supported with AI analysis. This all leads to better performance for an asset we put in the field.

Longer term, we are on the path to electrification. This will eliminate the mechanical banging and clanging that represents vibration and, ultimately, wear and tear. With an electric motor, the transmission goes away, and you go from zero to 2,000 RPM smoothly without any vibration or mechanical shifting. The uptime just gets better and better.”

Completion intensity, or the amount of sand packed away per foot of interval during a frac has also been on the increase. Early designs were built around 1,000 pounds per foot-PPF, of interval. Recently frackers in the Haynesville play have used ~3,000-3,500 PPF to pack as much sand as possible into their wells, with the idea that increased production will follow this increase in completion intensity.

Other basins, such as the Permian, have increased proppant loading into the 2,000-2,500 PPF, from earlier designs, as well. An article carried in JPT, in 2021 entitled, Data-Mining Approach Evaluates Production Performance In The Permian Basin, discussed this relationship between longer well lengths and the need for increased proppant intensity to fully optimize completions in this basin and found unequivocal benefits from higher proppant loadings-

“Tying cumulative production to completion and stimulation practices showed that increasing pumped proppant per well from 5 million to less than 10 million lbm yielded a 34% increase in 5-year cumulative average barrels of oil equivalent (BOE). Raising the pumped proppant per well to 10 million–15 million lbm and 15 million–20 million lbm increased 5-year cumulative BOE from the previous proppant range group to 27% and 18.5%, respectively.”

## Refracs

Finally, we come to Refracs. As the linked article notes, there can be a considerable amount of oil left behind from the initial fracture treatment. Particularly in wells that were fracked before current theories about well spacing and completion intensity became widely adopted. The idea behind a refrac is to stimulate rock that was untouched in an early treatment and receive production that has remained locked up over the years.

The article notes that one challenge to widespread implementation of refracs is the limited availability of equipment and manpower, but also notes the huge opportunity set refracs bring.

“While acknowledging there remain a number of challenges to wider uptake, proponents maintain that there are huge numbers of candidates spread across the big onshore US basins that are likely ripe for refracturing. Eventually, as they see it, the industry will pivot in a more concerted way to rejuvenate this inventory which may add up to tens of thousands of wells.”

## Improved Oil Recovery

Chemistry has been a neglected element in improving results from shale wells. For much of the shale era, oil companies have relied mostly on brute hydraulic force to overcome the rock’s frac gradient and inject tons of sand through the fissures created into the reservoir to obtain oil and gas. That is starting to change.

Ryan Ezell, CEO of Flotek Industries, (NYSE: FTK) sat down for a discussion on how chemistry is playing a role in what he calls, “Improved Oil Recovery.”

“We have this massive dataset containing physicochemical properties of over 20,000 wells that we have digitized and can allow us to analyze at the unique characteristics of a candidate reservoir and design optimized treatments that address the potential components of formation damage that pumped fluids could induce. We have proprietary software that uses utilizes AI-Machine Learning, drawing from the dataset to fine-tune our analytical procedures and subsequent recommendations.

This enables us to deliver a prescriptive recommendation of friction reducers, clay inhibitors and other elements of the treatment that are specific to the rock being treated. It not only improves the chemical formulation technically, but it also helps to control costs. We just pump what the program recommends rather than using speculative guesswork.

It is important to understand that shale reservoirs often have Nano-Darcy permeability. (A Darcy is a measure of the flow capacity of the rock) If we do not precisely match these reservoir characteristics, then we can do harm that doesn’t always show up immediately but may impair long-term recovery from the well.

We also have case studies where the IP30’s (the Inflow Performance over 30 days), has improved 15-20% using the application of thermodynamically stable systems like complex nanofluids, or CNF’s, versus offset wells where compatible chemistry was not deployed.”

## Summary

There is no way to cover every aspect of technological improvement that is helping to sustain current daily output. That said, we have explored some of the “Work-Horse” technologies-

- Understanding the Reservoir with applied Machine Learning,
- Drilling- Smart MWD BHA’s supported by AI applications, Walking Rigs, Improved-Fit for purpose drilling fluids,
- Completions-step change improvements in perforating and fracturing techniques that save time and deliver higher total returns from the wells.
- Improved Oil Recovery technologies that use optimized chemistries to increase oil output.

Collectively these technologies make substantial contributions to the industry’s ability to maintain shale output at current levels. All of the folks I interviewed were of the opinion that while challenges remained, the technologies they were individually deploying added up to a bright future for the shale drilling industry.