Investing in Energy

Will the good times keep rolling? – Top upstream trends for 2023

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Key implications:

After navigating the treacherous waters of the pandemic and the downcycle, upstream operators had their best year in decades in 2022, fortifying balance sheets and delivering cash flow surpluses that were the envy of the equity markets. But moving from zero to hero has furnished operators with a novel set of challenges as they seek to build on their success to show sustainable value.

This report highlights our view of what will unfold in the year ahead both inside and outside the sector and will serve as a guide for the research topics we will tackle throughout 2023.

1. **Not screwing up the (last?) oil boom.** Cash will rain down again, but the blockbuster pace of capital returns in 2022 will decline as prices moderate and capital efficiencies erode due to continued service sector inflation and fewer DUCs available to liquidate. Importantly, companies will not "take the bait" and reinvest heavily to grow production. Global capex and project final investment decisions (FIDs) will reach pre-pandemic levels but won't adjust upward to account for the price upcycle, the 2020 investment hole, or the downshift in shale reactivity.
2. **Right or wrong, it is tough to bet on long-term oil.** The growing uncertainty around the trajectory of long-term oil demand tends toward less greenfield exploration and more exploration of green businesses. As governments and industry both accelerate promises of net zero, the perception of the risks to the future of oil and gas profitability rises.
3. **The new pricing rules create a playing field between $70/bbl and $120/bbl WTI. Less energy price panic and more acceptance of "higher for longer."** The global oil market continues its search for a new, reliable price formation mechanism as the 2015-2019 model–in which shale delivers all marginal barrels below $60/bbl–has disappeared. Finding the new mechanism and equilibrium will take time and the road will be bumpy. Yet we believe the market is learning about how supply and demand react at different bands of oil and gas pricing.
4. **"I'm not dead yet": Shale refuses to go on the cart and the sweet spot exhaustion story is overdone.** At WTI prices above $85/bbl, US shale outperforms the current (low) growth expectations. Even limited to less than 320 completion crews, the industry can deliver 700,000+ b/d of entry-to-exit growth for the next several years. Furthermore, our analysis suggests that well quality degradation is limited to the Eagle Ford, with other areas unable to improve much but maintaining recent productivity levels.
5. **North Americans and NOCs push harder on energy transition investment but stay close to core skillsets.** Meanwhile, the divergence of the aspirations and portfolios of European IOCs continues to grow. All sides of the energy transition debate are interpreting the upheavals of 2022 as validating their view of the need for change. In reality, everyone is in a better spot than a year ago and is moving faster.
6. **Buy 'em back.** With balance sheet repair completed and regular dividends re-established, companies will increasingly favor the flexibility and perceived permanence of share buybacks over special dividends, acquisitions, and increased capex.
7. **Looking for a piece of the global LNG bonanza.** The explosion of LNG prices in 2022 and the drive to disconnect Europe from the lifeblood of Russian gas is impacting portfolio decisions across the upstream sector.
8. **"We must carbonize before we decarbonize."** Producing countries in the developing world will become more vocal in the debate over the energy trilemma (clean vs. secure vs. affordable) and on their plans to leverage their hydrocarbons for development. Gulf countries/NOCs will position themselves as winners in all three dimensions.

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1. **Not screwing up the (last?) oil boom.** Cash will rain down again, but the blockbuster pace of capital returns in 2022 will decline as prices moderate and capital efficiencies erode due to continued service sector inflation and fewer DUCs liquidated. Importantly, companies will not “take the bait” and reinvest heavily to grow production. Global capex and project FIDs will reach pre-pandemic levels but won’t adjust upward to account for the price upcycle, the 2020 investment hole, or the downshift in shale reactivity. Service companies will also adopt a conservative approach, both due to potential stranding and to avoid repeating the overbuild of previous cycles.

   In the North American shale patch–the poster child for chasing growth–capital discipline will continue to hold in 2023, especially as the absolute return of capital moderates due to lower prices. Sharp annual capex increases reflect only the rising run rate in 2022 and substantial cost inflation, and our new well counts through 2023 are consistent with the 4Q2022 activity level. Furthermore, we expect to see asymmetry at work: if prices come in below budgets in 1H2023, we expect companies to trim drilling and completion capex. However, should prices rise above the $75’ish levels that we believe are embedded in most E&P budgets, companies will continue to bank the windfall. While discipline will be touted, it is also true that the E&Ps’ new sobriety will largely go untested in 2023 due to continued service sector constraints that place practical limits on a return to the go-go performance of 2016-2019.

   Large US gas-focused E&Ps deserve special mention: they adopted the new business model even before the oil producers, but performance was constrained in 2022. In addition to widespread, massive hedging losses and infrastructure constraints in the three best gas areas, gas-focused operators devoted nearly 50% of their free cash flow to simply repairing balance sheets. While the window of $6+/MMBtu Henry Hub gas prices may have passed, the companies’ debt loads are in a healthier state and returns to shareholders should blossom as the group emphasizes free cash flow generation over volume growth.

2. **Right or wrong, it is tough to bet on long-term oil.** The growing uncertainty around the trajectory of long-term oil demand tends toward less greenfield exploration and more exploration of green businesses. As governments and industry both accelerate promises of net zero, the perception of the risks to the future of oil and gas profitability rises.

   In the financial markets, this phenomenon is playing out in the heavy discounting of long-term cash flows for oil and gas assets. In the parlance of Net Asset Value calculations, the “terminal value” for producers, which makes up a substantial portion of the total value of the enterprise, is low or even nonexistent. Along with the notion of cyclicality, this helps to explain the low trading multiple.

   In terms of upstream investments, we would argue that the risks to oil and gas demand are having an impact on the marginal investment. We believe that executives are (usually implicitly) applying a “stranding” risk to longer-term opportunities for traditional oil and gas production.

   This perceived strand risk already is manifesting itself in the form of cuts to exploration financing and budgeting–this activity being the purest and riskiest form of value addition in the upstream. Exploration today is increasingly the domain of the experts who want to retain portfolio optionality/flexibility and have proven that they can deliver value in the past (and thereby retain some boardroom support to continue). This group consists mainly of global integrated oil companies (GIOCs) and select larger independents, plus an ever-reducing number of smaller and contrarian players, who are continuing to seek to add new acreage "while we still can."

The gains that larger operators have made since 2014 in reducing cycle times is allowing them to commit to fast-tracking the successful emerging basins (Guyana, Namibia, Eastern Mediterranean). The group is applying selective focus on fast-track monetization of "their best stuff" and impressive efforts to reduce costs through standardization are paying off.

The exploration business currently is delivering more overall volumes and improved efficiency (volumes discovered per exploration well) versus the end of the last decade.

However, in the larger picture, the world of exploration is narrowing, with the number of players and the size of the effort constricting. The scale has contracted from an annual average of ~1,450 new field wildcats during the last upcycle from 2001-2014 to ~800 from 2015-2019. The pandemic further cut activity to 500 wildcats in 2020 and 2021, and we expect last year's tally to only achieve this modest level. Even though companies are flush with cash, we do not see a return to even the pre-COVID level of exploration activity. If you strip out inflationary effects, any increase in exploration and appraisal spending going forward looks likely to be quite measured.

Thus, we would argue that the uncertain future of the market for oil and gas is inhibiting, on the margin, the sort of drive to target anchor projects and prove breakthrough basins that has characterized activity in previous upcycles. This may be the first time in the 150 years of the oil business that a boom (should it be sustained) does not lead the cash-rich oil companies to aggressively hunt elephants on a collective basis. Rather, they are likely to continue to focus most of their efforts on "finding oil where they already found it." It is working.

Reinforcing this trend toward companies placing bets on fewer and better geographies, the subsurface and geologic prospectivity will matter less, while the degree to which the basin is advantaged by having strong margins, optionality for gas and green investments, and a low-carbon footprint will matter more.

With exploration spending held in check, incremental spending will disproportionately go towards low-carbon activities instead. The Global IOCs will continue to ramp up investment (albeit at different paces among the various players) to meet medium- and long-term emissions reduction targets and build up new businesses. In addition, significant M&A activity in the low carbon sector by the Global IOCs in 2022 will put further upward pressure on organic low-carbon spending budgets going forward.

The other beneficiary of reduced appetite for projects with output in the 2030s is the North American shale sector. Despite often middling economics, shale competes well for capital due to its rapid NPV capture rate. In addition, its modular nature allows companies the flexibility to ramp up and down in tune with the margin cycle more easily. While not many companies have the portfolio that allows them to allocate to both shale and long-cycle projects, we believe those that do (ExxonMobil, Chevron, ConocoPhillips, etc.) will continue to prefer shale on the margin when considering new investments.

3. **The new pricing rules create a playing field between $70/bbl and $120/bbl WTI. Less energy price panic and more acceptance of "higher for longer."** The global oil market continues its search for a new, reliable price formation mechanism as the 2015-2019 model–in which shale delivers all marginal barrels below $60/bbl–has disappeared. Finding the new mechanism and equilibrium will take time and

the road will be bumpy. Yet we believe the market is learning about how supply and demand react at different bands of oil and gas pricing.

Our overall framework was that the global petroleum complex was not underinvested in the past seven years, but only because shale played such an outsized role in creating marginal barrels. Critically, however, that crowded out investment in the sort of long-cycle anchor projects that have traditionally underpinned new-source production. With shale hyper-elasticity diminished, those long-cycle resources may be technically available, but the time to initiate funding is long past. There is no possible way to bring those resources into production in the next several years. The system is thus effectively underinvested; the market is searching for the equilibrium price that balances this new supply side with a demand side that is only modestly price elastic in the short-term and evolving very slowly in a structural way (rising EV penetration, efficiency gains). If yet another unexpected major disruption arises, then the price risks are skewed to the upside as inventories remain heavily depleted and the levers that politicians used in 2022 may be less effective.

But barring another unforeseen tsunami, we believe petroleum prices across the board should consolidate the gains of the post-COVID era rather than set new highs. Oil prices should experience a soft floor as prices fall below $70/bbl, where OPEC acts and shale independents meaningfully pull back activity to maintenance levels, and a soft ceiling of $120/bbl, where affordability issues curb demand and consumer government interventions intervene meaningfully in markets. Both sets of forces begin at $90/bbl and become fairly decisive below $70/bbl and above $120/bbl.

Begrudging acceptance by consumers and consumer governments that oil prices have experienced a step change upward should also take some of the spotlight off the upstream. On a year-on-year basis, energy prices should be deflationary, though their rise in 2022 will continue to reverberate through consumer pocketbooks and damage disposable income. At prices below $90/bbl WTI, we would expect political pressure for extraordinary measures such as windfall profits taxes, price caps, and tax holidays to wane.

Global gas producers will similarly enjoy historically high prices, but the removal of the fear premium will make this year look quite different. 2022 demonstrated the old adage that nothing cures high prices like high prices. Demand did, in fact, respond to painfully high gas prices. In 2023, even if Europe has problems filling its storage, the market's elasticity and the successful expansion of supply via LNG should help keep prices in check. Furthermore, a portion of the reduction in European consumption will show itself to be a permanent gain in efficiency, further calming the market even in the event of no imports from Russia.

In North American gas markets as well, we expect subdued prices to fall below $4/MMBtu Henry Hub. Even without the recent warm weather, demand is structurally stagnant, export market demand will take a multi-year breather, and supply has shown that it will respond to signals such as those we saw in 2022. In fact, given supply and demand trajectories, we would not be surprised to see a (price) overshoot to the downside to force a moderation of gas-directed drilling.

4. **"I'm not dead yet": Shale refuses to go on the cart and the sweet spot exhaustion story is overdone.** At WTI prices above $85/bbl, US shale outperforms the current (low) growth expectations. Even limited to less than 320 completion crews, the industry can deliver 700,000+ b/d of entry-to-exit growth for the next several years.

It is true that shale is constrained by both financial (capital discipline) and physical (equipment, logistics, and labor) factors. But our analysis suggests that the plateau in oil production from January through August 2022 demonstrated less an inability to grow than a delay in the cycle time from spud to onstreaming. Thus, the ramp in activity during 1H2022 did not show up in the summer, but it does appear to have yielded our expected results in the latter half of the year. In 2023, the expansion may again be jagged, but our view remains that operating more than 300 completion crews to complete the specific wells being spud yields growth in the US onshore of 600,000-800,000 b/d in 2023. While this is a far cry from the go-go years, it still represents the largest addition to global supply and is significantly above the current consensus growth outlook.

Another aspect of 2023 US growth will be a reversal of the trend toward domination of activity and wedge production by private operators. As the US L48 onshore industry emerged from lockdowns in 2021, public companies took the opportunity to fully pivot their businesses into cash-generating operations–a task long thought impossible by many. However, private operators either did not get the memo or saw their opportunity to catch the upcycle wave. They aggressively ramped up activity to pursue growth. However, the privates' share of activity peaked in 3Q2022 at about 55% of horizontal rigs. We expect 2023 will see larger companies–both supermajors and independents–pick up rigs that privates lay down as they find it difficult to manage cost inflation.

Adding to the debate about US production, the mainstream press and some analysts have trumpeted the notion that most companies have relocated to inferior acreage due to exhaustion of the core areas. The concept of sweet spot exhaustion is uncontroversial. Material well productivity degradation is the eventual fate of every shale play, and we believe technology improvements will not overcome the fundamental differences in rock. And while it will be a factor in 2023, our evaluation of the data does not support the conclusion that well productivity–when properly normalized–is degrading in a widespread way. The productivity of the average 2022 oil shale well is only modestly below previous years, with slightly deteriorating performance in the very best acreage somewhat offset by improvements in non-core areas.

When parsing the inevitable barrage of stories in 2023 about the demise of shale productivity, a few observations on shale productivity dynamics are good to keep in mind:

- Development theoretically proceeds from the best to the worst acreage. However, reality is much messier. Every company only has the acreage that it has, and many are not in the core. In addition, it is rational in multi-bench areas to prioritize development of lower quality rock if the cost synergies of co-development overcome the penalty of lower production.

- The erosion of well performance due to forced migration to lower quality areas or tight spacing/interference has begun to occur to selected players but is not yet widespread. The clearest signs are in the Eagle Ford core. The Bakken and the Wattenberg/DJ are not far behind.

- Per foot productivity gains from controllable factors (especially completion design) became incremental after late 2018. The era of rapid improvements is over.

The other drag on performance has been dilution: As noted above, we expect publicly listed independents to account for a greater proportion of new wells in 2023, which should help to bolster average well productivity modestly. Over the past four years, private operators have adopted best practices for fracking wells. As a result, there is currently very little difference in productivity between a private's and an independent's well. However, it is true that the acreage endowment of the privates is generally lower quality than that of the listed companies. Thus, the rising share of private operators in 2021 and 2022 modestly diluted the average well drilled, creating a slight headwind to production growth. That should turn to a tailwind in 2023.

5. **North Americans and NOCs push harder on energy transition investment but stay close to core skillsets.** Meanwhile, the divergence of the aspirations and portfolios of European IOCs continues to grow. All sides of the energy transition debate are interpreting the upheavals of 2022 as validating their view of the need for change. In reality, everyone is in a better spot than a year ago and is moving faster.

Investors, environmental groups, and governments continue to exert pressure on the global integrated oil companies

(GIOCs) to progress with the energy transition, and the recent energy security challenge in Europe has strengthened the argument for accelerating it. Accordingly, GIOCs are expected to continue to increase spending on low-carbon activities in absolute and relative terms, with differentiators being the types of low-carbon businesses being pursued and the degree of diversification in such businesses. The group will continue to rely on revenues generated from oil and gas production (and in some cases, divestments) to fund these low-carbon business activities. Furthermore, local or regional market incentives are also playing an increasing role as countries seek to re-shore supply chains and protect jobs. With most of the GIOCs having set net-zero emissions targets by 2050, GIOCs are likely to be increasingly more transparent and exhaustive in their emissions-related disclosures, providing more operational metrics and interim objectives. Nevertheless, it still remains to be seen to what extent, if any, the stock market will reward the GIOCs for these changes in strategy and investment. Thus far, that has been elusive.

For many NOCs, the focus is likely to be more on decarbonizing their oil and gas supply chains than investing in organic low-carbon activities as standalone businesses. NOCs–particularly those with relatively higher hydrocarbon reserve lives–have a strong interest in extending the fossil fuel era for as long as possible. Pressure to decarbonize, however, from civil society, governments, domestic voters, and concerned citizens continues to build. While improving operational efficiency, reducing GHG emissions, lowering methane intensity, and making progress–however slowly–in reducing Scope 1 and 2 emissions will be an ongoing priority for most NOCs. Some, especially certain NOCs in South America, have been expanding into lower carbon businesses (power transmission, solar, wind, etc.). For NOCs, 2023 could also be a breakout year for decarbonization projects that support 'core carbon' activities i.e., oil and gas production. NOCs will move faster on incorporating proven and scalable technologies such as electrifying offshore operations to show progress on emissions intensity and will also explore emerging technologies such as CCS as part of new project developments as these reach FID. However, long-term decarbonization targets are unlikely to be aggressively pursued by most.

We expect a further step up in low-carbon investments by US E&Ps. Up until now, the US E&Ps have limited their emissions reduction efforts to minor, relatively lower cost, operational enhancements like replacing old valves. Every company is focusing on methane reduction (which makes sense), and we have faith in the industry's ability to be very successful in this endeavor now that energy and capital are flowing in earnest. In 2022, we saw a lot of effort being put into flare reductions, pneumatic device replacement, leak detection, and emissions measurement. In 2023, we expect more companies to become more creative in finding ways to generate further emissions reduction. Electrification is the other theme, and a number of companies are working on leveraging solar/wind and hybrid power sources and other ideas in order to reduce diesel consumption and reduce reliance on the power grid. We also expect more new initiatives targeting water demand in 2023. Finally, because virtually no operator has found a way to deal with the "hard-to-abate" emissions, many will continue to rely on carbon offsets to reach lofty goals. For more, please see North American E&Ps are committing to improve ESG performance, but reporting standards need to align.

As the operational enhancements considered "low-hanging fruit" for emissions improvement become exhausted, US E&Ps will naturally seek greater diversification of their businesses. They remain wary of the returns of energy transition investments, and are also concerned about whether they have (or can realistically attain) a comparative advantage that allows them to perform. This has led the industry to perceived ancillary spaces where they can leverage existing skillsets–namely in the areas of CCUS, gas integration, and blue hydrogen. In this arena, 2022's Inflation Reduction Act (IRA) will spur significant activity but expect mostly cautious forays into these spaces this year, including announcements of heads of agreement, contingent investments, etc. Overall profitability remains unclear and allocating value and risk to the various segments across the long chains of such projects will take time to figure out.

6. **Buy 'em back.** With balance sheet repair completed and regular dividends re-established, we believe companies will increasingly favor the flexibility and perceived permanence of share buybacks over special dividends, acquisitions, and increased capex.

   The macro environment is reinforcing the attractiveness of buybacks. The sector entered 2022 with a wide yield advantage between their dividend payments and other interest paying options, with the Fed Funds rate near zero. But this yield spread relationship flipped later in 2022, with the Fed Funds rate moving currently higher than the median dividend yield for the large US oil-focused group. With risk-adjusted dividends less competitive, the mismatch of surging cash flows and persistently low trading multiples made buybacks compelling. Our assessment of the results of various alternatives for cash disposition suggests that share buybacks emerged in 2H2022 as the most effective way to add value, though the situation varies by company (for more, please see Return of capital strategies matter–Assessing the relationship between return of capital and stock valuation). Companies should be more selective on the timing of purchases, but the fundamental conditions that drive the appeal remain in place.

7. **Looking for a piece of the global LNG bonanza.** The explosion of LNG prices in 2022 and the drive to disconnect Europe from the lifeblood of Russian gas is impacting portfolio decisions across the upstream sector.

   The initial hopes for a bevy of high-priced contracts to feed Europe for several decades has given way to the reality of LNG's commercial complexity, inevitably long cycle times, and Europe's conflicted approach to gas (yes to short term, no to long term). Nevertheless, energy security concerns have effectively revived the notion of the "gas bridge" to the end state of the energy transition, and we believe companies will pivot toward increasingly favoring development of gas resources, and commit spending to exploration to that end.

   In this push for gas, we believe incumbents will be the best placed to take advantage of the opportunities for new plants. Qatar is likely the biggest winner of all; while the new resources to be developed in its expansion may not equal the profitability of previous investments, it remains a world-class asset. We believe that the timelines, scale of infrastructure, and risks of LNG development continue to make it difficult for new basins to enter the game, despite excellent resource bases.

   North America is the other obvious place for new supplies. Here, we expect to see some of the US E&Ps making strategic positioning moves around LNG exports. With the new US LNG export expansions scheduled to go on-line in early 2025, we expect 2023-2024 will be the time for US E&Ps to position themselves to exploit this opportunity to sell their natural gas production at higher than domestic gas prices.

   LNG positioning is a tricky business that calls for commercial expertise that US gas producers do not necessarily possess. And even the largest independent gas producers do not have the scale that LNG participation and risk management have traditionally required. But the arbitrage opportunity is massive, and E&P firms need new ways to add value, so we would expect to see producers get creative as they seek structured positions further down the value chain. This effort will include US natural gas-focused operators continuing to focus on independent certification of sustainably sourced gas. Even if it does not yield a premium price, demonstrating an impressively low-carbon footprint will be viewed as table stakes for sales to European LNG consumers.

The other result of chasing LNG is likely to be finding new resources dedicated to LNG feed gas. Our analysis suggests that the Haynesville, which is nearing the end of its consolidation (at least for the core), remains the pillar of gas supply growth but that the industry will need to de-risk and buy/develop new plays to provide reliable supply for long-lived, expensive liquefaction plants. Thus, gas resources in certain areas that companies rightfully ignored in a $2.25/MMBtu Henry Hub world, become attractive in the new range of gas prices. Importantly, these resource's assets must be able to access LNG facilities located along the Gulf Coast, using either existing infrastructure or intra-state pathways. In our view, the most likely candidates are:

- East Texas tight (not shale) gas.
- Dorado/dry gas window of the Eagle Ford/Austin Chalk.
- Permian areas that producers abandoned in the stampede to the oilier acreage.
- Central Oklahoma

8. **"We must carbonize before we decarbonize."** Producing countries in the developing world will become more vocal in the debate over the energy trilemma (clean vs. secure vs. affordable) and on their plans to leverage their hydrocarbons for development. We see Gulf countries/NOCs positioning themselves as winners in all three dimensions.

Last year re-introduced energy security into the balance. 2023 will see developing countries more assertively proclaim their plans to develop hydrocarbons to advance economically before having the level of wealth that makes a transition to deep decarbonization possible. In short: "We must carbonize before we decarbonize." This line of reasoning has reasonable arguments both for and against, but it is very controversial. We expect that it will become one of the central energy debates of 2023 and will disrupt some of the traditional alliances.

Gulf NOCs will be especially active in the discussion, as the UAE hosts the COP28 meeting in December and Saudi Aramco seeks to position itself as a leader on the issues. In recent years, Gulf countries have talked the talk about their ability to deliver a reliable, low-cost, and low-carbon engine of future supply. And while they still face criticism about their transparency or lack thereof, they now have the money to walk the walk.

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