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THE END OF ABUNDANT ENERGY: SHALE PRODUCTION AND HUBBERT'S PEAK

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Crude oil fundamentals are very tight and risk getting considerably tighter. Investors continue to starve energy companies of much-needed capital, the lifeblood of a solid supply base. Although the trend of lower spending has been in place for several years, our models tell us we are nearing a critical inflection point: the growth in shale oil production -- the only source of non-OPEC+ production growth over the past two decades --- may be coming to an end.

Few of us properly appreciate the importance of the shales. Not only were they the only source of incremental growth over the past decade, but they were also tremendous in absolute terms. Between 2010 and 2020, US shale oil production grew by 7.6 mm b/d, while natural gas liquids (nearly all from shale) increased by 4.0 m b/d. Total liquid production from the US shales grew by 11.6 mm b/d – more than Saudi Arabia's production of 10.5 m b/d. Shale

gas production grew an incredible 65 bcf/d over the same period. When converted to barrels of oil equivalent, shale gas added another 10.8 m boe/d – equivalent to a second Saudi Arabia.

Few people have acknowledged shale's importance to global oil and natural gas markets. History books discussing Saudi Arabia in the middle of the last century devote most of their attention to oil industry developments. On the other hand, when people think of shale producers, they often think of “value destruction.” Instead of focusing on “value destruction,” commentators should emphasize the importance represented by unlocking the US oil and gas shales. In just ten years, oil companies brought online the equivalent of two Saudi Arabias in the same country. An incredible achievement, and yet today, the shales are primarily mentioned in the context of E&P company value destruction and climate degradation.

Shale development had many consequences, including massively shifting the US current account deficit and reducing the geopolitical influence of foreign oil producing countries.

In 1973, President Nixon announced “Project Independence,” an attempt to make the United States an energy exporter. For the next 35 years, the United States went in the wrong direction—importing more and more oil and gas. However, by the end of the 2010s, the US had finally become a net energy exporter, thanks to the shales.

Surging shale production also allowed many investors and analysts to forget about the energy challenges society had faced in years past. For example, in the early 2000s, investors were fixated on “running out of oil.” The rise of Chinese energy demand was running into a period of lackluster non-OPEC production growth, resulting in surging prices and widespread fear. Oil ran from \$25 to a record \$145 per barrel in just five years.

Amid such widespread concern, several theories surrounding resource depletion and energy economics took hold. Once shale production began to surge, most of these theories – which investors had taken seriously only a few years prior – were discarded and openly mocked.

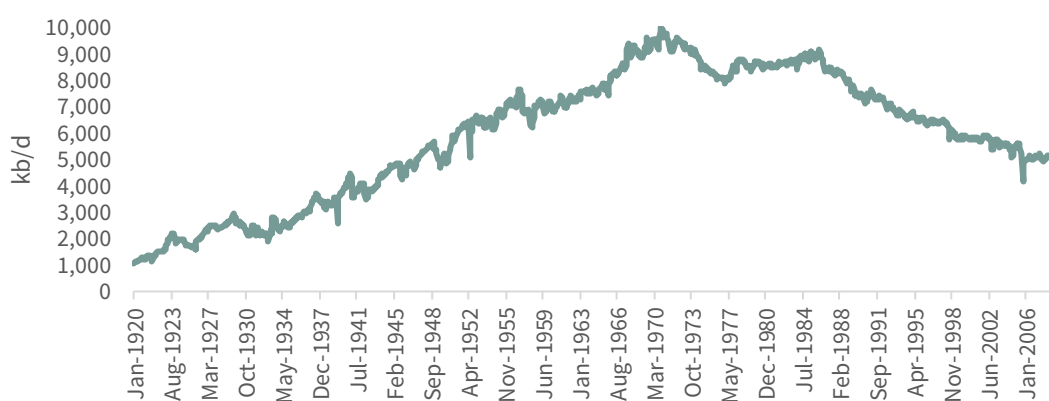
In recent years, Goehring & Rozencwajg has become convinced that shale production growth will slow and eventually turn negative. So far, the data has confirmed our thesis. If current trends continue and the shales do indeed plateau and roll over, global oil markets will have lost their only source of growth. Many of the resource depletion theories of the 2000s will likely return as critical issues in the 2020s. Investors would be wise to study them now.

The first theory we revived in 2018 was energy return on investment (EROI). Professor Charles Hall of the University of Syracuse first developed the concept in the 1980s. His

work focused on studying how much energy was required to produce usable work. Professor Hall's work was prevalent last decade as oil companies struggled to replace reserves and grow supply. The industry was forced into developing fields that required more and more energy (either oil sands or deep water offshore) for the same production level. Hall and others argued that ever-lower EROI would eventually impact economic growth. This thesis went from popular to ridiculed as soon as the shales ushered in a period of intense production growth. We found Professor Hall's work on EROI extremely important and used it to assess the poor efficiency of renewable energy.

The next theory we would like to revisit is Peak Oil. Ironically, today many analysts refer to peak oil demand, but originally peak oil referred to supply. The theory is associated with M. King Hubbert, a controversial Shell geologist from the 1950s and 1960s. Hubbert believed that an oil field production curve would resemble a bell-shaped curve under ideal unconstrained circumstances. Production would grow at an accelerating rate, then level off, plateau, and ultimately decline at a rate mimicking its growth phase. Hubbert also developed techniques known as "linearization" to estimate a field's total recoverable reserves. He believed that production would peak when half its reserves had been produced. At the Society of Petroleum Engineers meeting in 1956, Hubbert used his theories to predict that US crude production would peak in the 1970s at around 10 mm b/d. Hubbert made two predictions in his 1956 speech: one, assuming 150 bb barrels of recoverable oil, the other based on 200 bn barrels. In 1962, he repeated his 200 bn barrel projection, which implied production would peak at 10 mm b/d in the early 1970s. His presentation was shocking: US production had grown steadily over the previous years. When US supply did indeed peak in 1970 at 10 mm b/d, Hubbert's work gained widespread attention.

FIGURE 1 US Crude Production 1920-2008



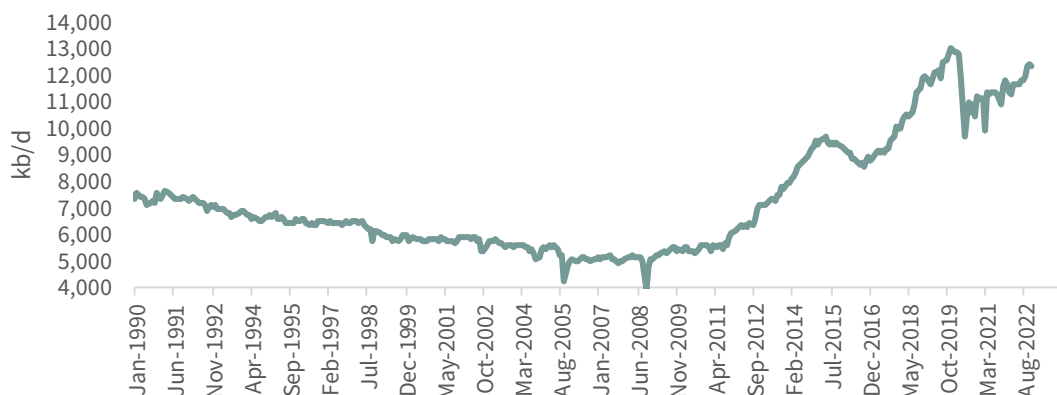
Source: Energy Information Agency.

Between 1970 and 2008, US production fell steadily. By the 2000s, most people saw oil as a scarce resource and believed society should treat it dearly.

The development of shale oil spelled the end of public interest in Peak Oil. Like Professor Hall, many openly dismissed and even ridiculed Hubbert's work., US production bottomed at 4 mm b/d in 2008 and, driven entirely by the shales, has grown since to become the largest

oil producer in the world.

FIGURE 2 US Crude Production 1990-2022

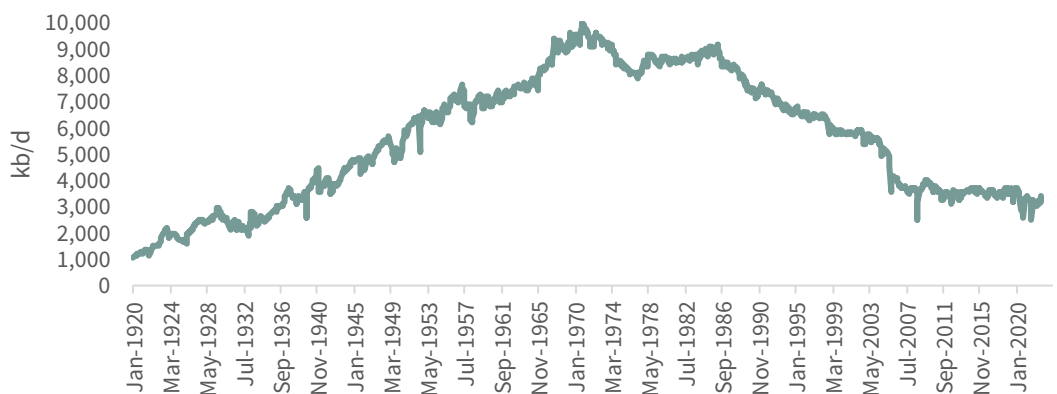


Source: Energy Information Agency.

Given surging production over the past decade, it is easy to understand why EROI and Peak Oil have been thrown aside and labeled “blown calls.” However, we think it is completely irresponsible to dismiss them entirely. There are valuable insights in both theories; those investors that ignore them, do so at their own risk. In the case of EROI, a proper understanding of the framework predicted the disastrous impacts of renewable energy we all face today. In the case of Peak Oil, we would argue that shale trends have completely obfuscated trends in the rest of the world.

While Hubbert’s predictions look ridiculous when considering total US liquids production, focusing only on conventional crude production suggests Peak Oil is alive and well. Last year, the US produced 3 m b/d of conventional crude oil – 7 m b/d or 70% below the peak reached 52 years ago. In other words, the shales bailed out total US production but did nothing to change the forces underpinning Peak Oil and depletion. On a global basis, conventional oil production (total production ex shale and Canadian oil sands) has exhibited no growth in 17 years.

FIGURE 3 Conventional Crude Production 1920-2022



Source: Energy Information Agency.

We agree with critics who argue that Peak Oil neglects the impact of new technologies that improve oil recovery. Shale development itself would fall into this category. However, it is equally imprudent to implicitly suggest the dramatic shale growth of the 2010s will continue forever and neglect the underlying forces of depletion and Peak Oil entirely. In the case of EROI, it regained relevance once we applied the framework to another energy source (renewables). In the case of Peak Oil, we believe Hubbert's theories will regain relevance once shale production rolls over and the underlying depletion problems of conventional oil are exposed. Our models tell us that the inflection point may be quickly approaching.

In 2019, we announced the results of some very original research regarding shale drilling productivity. We wanted to understand better why wells in the Big Three basins (Eagle Ford, Bakken, and Permian) were producing more and more oil. Between 2014 and 2018, the average well in the Eagle Ford, Bakken, and Permian grew by 50, 20, and 100%, respectively. Given such high levels of productivity, the industry was able to grow shale production by 1.6 m b/d in 2018.

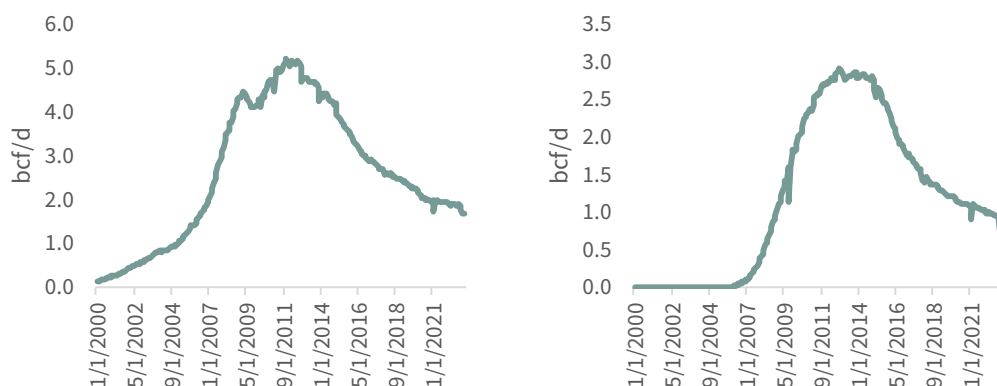
The conventional wisdom at the time attributed the increased productivity to better drilling and completion performance. In other words, the industry was getting better at drilling shale wells. We built an artificial neural network to help us better understand all the underlying forces that could impact shale gas drilling and production. Our artificial intelligence engine confidently told us what inputs were driving drilling productivity improvement. Drilling location was the most significant factor influencing drilling productivity, not how companies drilled the wells.

E&P companies successfully determined over time the "sweet spots" of the basins, where attributes such as thermal maturity, thickness, permeability, porosity, and organic content were ideal. In 2014, we estimate 45% of all drilling occurred within Tier 1 areas, whereas by 2018, it had surged to over 65%. If the industry were getting better at drilling wells, then previously low-productivity drilling locations would be converted into high-productivity locations, allowing production to continue to surge. Instead, we determined the industry was "high-grading" or drilling its best wells first. Our neural network told us that companies were drilling their best top-tier locations in all their basins. If our neural network was correct, we argued in 2019 that per well productivity would peak and begin to fall as tier 1 prospects dwindled, leaving the industry to either drill many less productive wells or, if not, see their production decline.

Simply put, we concluded the shales suffered from a depletion problem. Our conclusion was highly controversial at the time. Given the shale's prodigious production growth, almost everyone believed they were limitless. Analysts talked about chronic oversupply without once thinking about the underlying geological constraints. Although the shales are extremely large, we determined they behaved precisely like traditional (albeit enormous) fields. We

concluded that shale basins exhibited Hubbert-style production profiles: they ramped up, plateaued, peaked, and declined. The two earliest shale basins, the Barnett and Fayetteville, peaked between 2011 and 2014 and have both since declined by 70%.

FIGURE 4 Barnett and Fayetteville Production



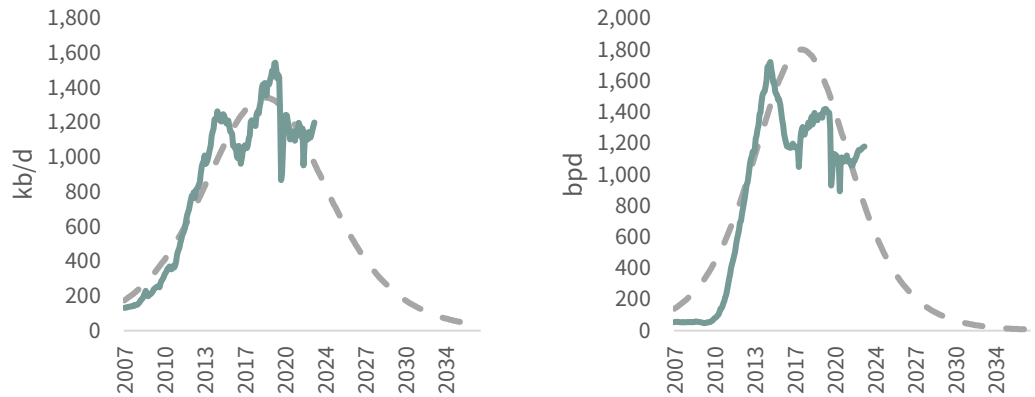
Source: zEnergy Information Agency.

Both of these early shale basins were gas fields, but our understanding suggested to us that shale oil fields would behave similarly. Looking at the Barnett and Fayetteville, we observed that production stopped growing once half of all the best wells were drilled and began to fall sharply once Tier 1 development reached 65%.

Looking at the Bakken and Eagle Ford, we concluded in 2019 that both fields had likely reached maximum production and would undergo a consistent decline. Our neural network determined that Tier 1 development reached 55% and 50% by late 2019 in the Eagle Ford and Bakken, respectively. Almost immediately after we published our findings, COVID resulted in widespread shut-ins of producing wells and a drilling decline of 70%, making our predictions impossible to verify.

With COVID impacts now behind us, and after two years where oil averaged \$81 per barrel, we can assess our results. Exactly as we expected, neither Bakken nor the Eagle Ford has been able to grow. Since the end of 2019, combined production from both basins fell by 500,000 b/d. Even an increase in drilling activity has had little impact. Since the end of 2020, completions in both plays have grown by 50%, yet production over that time has been flat. The explanation is well productivity, which has fallen by 10-20% since making its high in 2019. Our neural network was correct – the Eagle and Bakken were suffering depletion and running out of high-quality inventory. As you can see in the two charts below, both the Eagle Ford and the Bakken are tracing out near-perfect Hubbert Curves. In our following letter, we will discuss the forces that are working at producing these curves in both fields and how these same forces are firmly at work in the Permian today.

FIGURE 5 Bakken and Eagle Ford Production w/ Hubbert Curve



Source: zEnergy Information Agency and G&R Models.

In our 1Q19 letter, we explained how the Permian still had room to grow. We estimated that Permian production would peak at 6.5 m b/d – 900,000 b/d above current levels. Compared with the Bakken and Eagle Ford at nearly 50% Tier 1 development, we estimated the Permian still had 65% of its Tier 1 wells left to drill. According to our estimates, the Permian would reach maximum production sometime in 2024-2025 and then begin to peak and decline like the other two basins. Again, our models were correct. Unlike the Bakken and Eagle Ford, the Permian grew by 800,000 b/d since the end of 2019 and by 1.2 m b/d since 2020. Production fell during COVID but quickly rebounded and surpassed the old highs.

Interestingly, the Permian has been the only basin to grow drilling activity since the end of 2019. In the Bakken and Eagle Ford, activity remains 10% below pre-COVID levels, whereas, in the Permian, activity is 5% above late-2019 levels. The answer is the superior inventory of remaining Tier 1 locations.

Unfortunately, this superior inventory is being drawn down. We estimate that closer to 45% of all Tier 1 Permian locations have been drilled. The Permian is quickly approaching the same level of development as the Bakken and Eagle Ford in 2019. Our models tell us the results will be similar: Permian production will peak, plateau, and decline much sooner than anyone expects.

Since building our first neural network, we have dramatically improved model design and data quality. Our original model used longitude and latitude to help predict productivity. We now have access to subsurface geological data, such as thickness, thermal maturity, clay content, organic content, permeability, and porosity. Of course, we also have three additional years of data since we first published the results of our original model.

In our following letter, we will detail the results of our work. The early results confirm our intuition: we have mostly drilled out our best areas in the Permian, and once Permian production declines begin, shale growth will be difficult, if not impossible, to achieve from there.

As shale growth slows, investors will be re-confronted with the concepts of depletion and Peak Oil. The development of the US shales has allowed us all to forget about these problems for over ten years. We urge investors to familiarize themselves with these topics because our models suggest they will be crucial in navigating markets in the future.

Investors and policymakers tend to fight the last war and often are blind to the changes that will impact the future. In the early 2000s, investors' focus on Peak Oil left many unable to see shale's transformative potential. Today, investors remain convinced the shales are endless and fail to see that depletion problems have already taken hold.

Along these lines, we want to leave you with a curious thought. On December 22, 1975 – three years after OPEC stopped shipments to the West, ushering in the first oil crisis -- President Ford signed a bill that limited US crude exports. Ford announced the bill would pave the way towards energy independence – something few believed possible. Only five years after signing, oil prices peaked at \$35 per barrel and spent the next 18 years falling 70%. Ford was fighting the last war and neglected to appreciate the new oil development in Alaska, the Gulf of Mexico, and the North Sea. Ford's law was repealed in 2015, allowing US crude exports for the first time in forty years. Lawmakers argued the legislation was outdated, given the massive surge in domestic production. They argued that the US was no longer at risk of embargoes; energy independence was imminent. Ford's predictions took five years to begin being proven incorrect. COVID likely delayed "peak shale" by a few years due to slower drilling activity. However, our models suggest that eight years after repealing the ban, the idea of abundant US energy has also been proven incorrect. We believe the result will be much higher oil prices from now on. We predict new interest in Hubbert's theories. Investors should familiarize themselves and be prepared for the potential arrival of Hubbert's Peak. The economic dislocations and investment opportunities will be massive.

The Incredible Shrinking Super-Majors Part IV: What the Stock Market thinks of ESG

“BP’s CEO Plays Down Renewables Push and Returns Lag”

“Mr. Looney [(BP’s CEO)] has said he is disappointed in the returns from some of the oil giant’s renewable investments [...]”

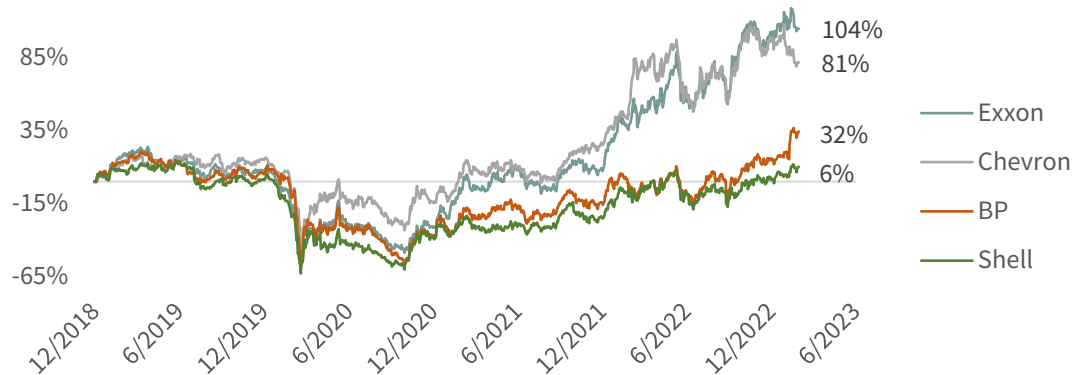
The Wall Street Journal, February 1st, 2023

Over the last five years, outside ESG advocates have pressured some super-majors into decisions that hugely impacted financial performance.

A considerable performance divergence has emerged between those companies that have bowed to ESG pressures and those that have not. Over the last five years, BP and Shell have actively pursued various ESG initiatives, while Exxon and Chevron have been more measured. The former have dramatically underperformed the latter.

Since the end of 2018, BP and Shell generated only modest returns. Exxon and Chevron generated 104% and 81% returns, respectively. Their shareholders also outperformed the general stock market. Investors were rewarded by owning Exxon and Chevron, two companies that stuck with their traditional hydrocarbon business.

FIGURE 6 Total Return Dec 2018 - Feb 2023



Source: Bloomberg.

We have discussed how super-majors have come under intense ESG pressure. Exxon replaced four members with those proposed by an ESG fund holding 0.04% of its common stock.

In response to a lawsuit filed by an environmental group, the courts ordered Royal Dutch Shell to reduce its CO₂ output by 45% before 2030. Shell has since come under attack from an activist shareholder that demanded it break itself in two. One company would be focused on hydrocarbons, and the other on renewables. The oil and gas entity would be starved of capital, which would be redirected into the renewable entity. The activist investor must have neglected to mention that renewable investment returns dramatically lag those of traditional E&P.

Shell's board last week announced it was being sued (this time in English courts) by ClientEarth, an "environmental law firm." The suit accuses Shell's board of "failing to manage

the company's climate risks" and "persisting with a flawed transition strategy." ClientEarth is attempting to replicate the success of Dutch environmentalists who won a lawsuit in 2021 under similar circumstances.

A US Congressional panel excoriated the super-majors only two years ago for not reducing their upstream capital spending fast enough. Today, the Biden administration criticizes these companies for not increasing their hydrocarbon production.

Chevron reported record 2022 profits and a \$75 bn share buyback program. In response, the Biden administration publicly criticized Chevron. "For a company that claimed not too long ago that it was "working hard" to increase oil production, handing out \$75 bn to executives and wealthy shareholders sure is an odd way to show it. We continue to call on oil companies to use their record profits to increase supply and reduce cost for the American people," said a White House spokesman. A White House spokesman also lashed out at Exxon following its 2022 profits a few days later: "It's outrageous that Exxon has posted a new record for Western Oil company profits after the American people were forced to pay such high prices at the pump."

Although the administration did not mention any specific recourse in these tirades, imposing a "windfall" profit tax is a serious consideration. Damned if you do, damned if you don't. The life of a super-major gets more complicated by the day. Even though all five super-majors have come under ESG pressures, responses have significantly differed. Exxon and Chevron have only minimally tried to shrink upstream capital spending. BP and Shell have decided to severely restrict upstream spending and redirect the capital into renewable energy.

BP and Shell's decision has negatively impacted their financial returns. The vastly different directions taken by Exxon and Chevron on one side and Shell and BP on the other have already been reflected in the financial returns and the stock market performance of all four companies.

Shell's ESG pressures have come from the outside—first from the Dutch government, next from an activist shareholder. In the case of BP, the ESG pressures have come from within the company. Twenty years ago, BP's chief executive, Sir John Brown, rebranded the company as "Beyond Petroleum" and pledged to keep emissions constant and be a "steward of the planet." Substandard returns on the original renewable investments under Sir Brown were eventually wound down and sold. However, Sir John Brown's green legacy at BP has re-emerged. BP's current CEO, Bernard Looney, worked directly for Sir Brown and was the BP executive responsible for managing the Horizon deep-water drilling blowout disaster and its intensely difficult multi-year cleanup, which has again directed BP in the "Beyond Petroleum" direction. Possibly influenced by Sir Brown and the deep-water Horizon drilling disaster, Mr. Looney has aggressively rekindled Sir Brown's goal of making BP a transitional energy powerhouse. Mr. Looney promised to slash BP's hydrocarbon production by 40%

by 2030 and that renewables would represent 50% of all capital expenditures.

ESG pressures have produced large underinvestment in Shell's and BP's traditional upstream businesses. Between 2007 and 2016, Exxon, Chevron, Shell, and BP each invested robustly in their upstream business. Exxon spent \$20 per BOE in upstream capital expenditures (\$30 bn per year). Chevron spent \$26 per BOE (\$25 bn per year), Shell spent \$25 per BOE (\$29 bn per year), and BP spent \$24 per BOE (\$17 bn per year).

Capital allocation diverged around 2016. Over the next six years, from 2017 to 2022, Shell spent only \$7.50 per BOE (\$10 bn). By 2022, Shell was spending only \$8 bn on its upstream assets – 70% below its 2006-2016 average.

BP's upstream capital spending followed a similar pattern. Between 2016 and 2022, BP slashed upstream capital spending to an average of only \$9 per BOE (\$8.7 bn per year), and by 2022 spent only \$6.50 per BOE (\$5.2 bn). Like Shell, BP reduced its upstream spending by 75% in 2022 compared with its 2006-2016 average.

Even though Exxon and Chevron also cut their capital spending significantly, their upstream investments remained much more significant on a per-BOE basis.

Between 2016 and 2022, Exxon's annual upstream capital expenditures averaged \$12 per BOE (\$17 bn annually) -- 50% more than Shell and BP. In 2022, upstream capital spending reached \$13 per BOE (\$17 bn) – 60% more than Shell and double BP.

Between 2016 and 2022, Chevron spent \$14 per BOE (\$16 bn per year) – 90% and 70% more than Shell and BP respectively. In 2022, Chevron spent \$10 per BOE (\$10 bn) -- 13% and 37% more than Shell and BP, respectively.

Although Exxon and Chevron cut upstream capital expenditures by nearly a third between 2019 and 2022, they outspent Shell and BP, which cut their spending by roughly one-half. More robust spending by Exxon and Chevron resulted in much shallower production declines than either Shell or BP.

Since 2019, Exxon and Chevron's oil and gas production has remained relatively steady. From 1Q2019 to 4Q2022, Exxon and Chevron's oil and gas production on a BOE basis fell 4% and 1%, respectively. In comparison, Shell and BP's production fell almost 40% and 15% over the same two-year period, respectively.

As a result of the difference in upstream spending, Shell and BP's earnings have lagged Exxon and Chevron's, despite rising energy prices over the last two years. Exxon went from earning \$3.43 to \$14.05 per share between 2019 and 2022 – an increase of 300%. Chevron went from earning \$6.00 to \$19.58 per share over the same period – an increase of 226%. By comparison, Shell went from earning \$1.95 to \$5.72 between 2019 and 2022 – an increase of only 193%. BP went from \$0.54 cents in 2019 to \$1.06 in 2022 – the laggard of the group by far.

BP's poor earnings came from two ESG-related sources. Not only did BP reduce traditional exploration and production investment, but they also redirected the capital into a renewable portfolio earning sub-standard returns. By February 2023, BP's CEO was forced to admit the poor renewable performance on his fourth-quarter earnings call.

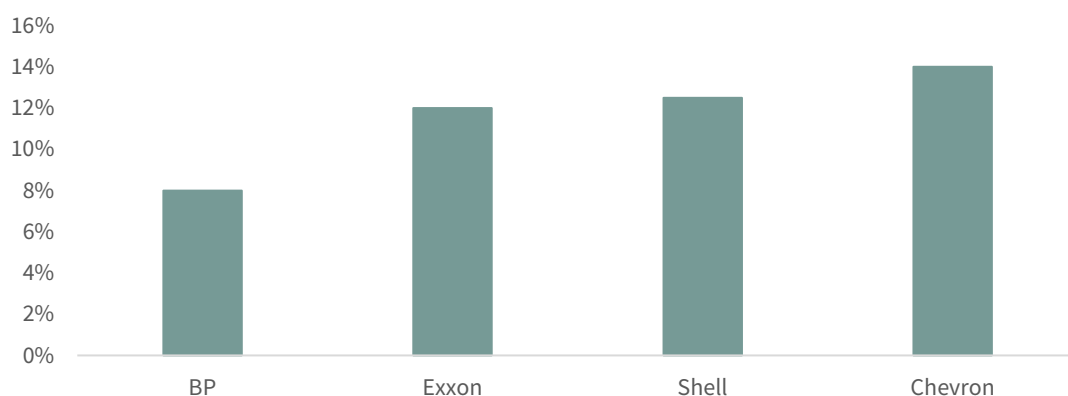
BP's decision to minimize high EROI (energy return on investment – our preferred metric for energy efficiency) hydrocarbon investment and to increase low EROI renewable investments has impacted its profitability. BP should serve as a warning to other super-majors contemplating a similar strategy. Dismal earnings are likely to follow.

As we have discussed extensively over the last several years, renewables' EROI is terrible compared with traditional hydrocarbons. We firmly believe that high EROI investments lead to high financial returns. Conversely, low EROI investments are much less financially profitable. It is no surprise that companies that are maintaining their upstream spending are seeing superior financial returns compared with those that redirected investment into renewables.

BP's renewable investments remain relatively small. Still, BP has admitted that its renewable portfolio's investment performance has negatively impacted total profitability.

Since 2019, BP generated an EBITDA return on assets of 7.9% compared with 12% and 14.2% for Exxon and Chevron, respectively – nearly 35% and 45% lower. Shell, which curtailed upstream spending but did not divert capital into renewables to the same extent as BP, enjoyed a return on assets of 12.6%.

FIGURE 7 EBITDA Return on Assets



Source: Company Filings, Bloomberg and Company Filings.

Several years ago, BP announced its intentions to reduce hydrocarbon production by 40% compared with 2019 and to have annual renewables investment reach 50% of total capital spending by 2030. In 2021 BP had a renewable base of 3.3 GW with a goal of reaching 50 GW by 2030. BP planned on increasing offshore wind and biofuel production to meet their lofty goal. BP just announced the takeover of Archaea, a landfill methane producer. BP paid \$4.1 bn for a company today with only 6,000 BOE of production and hydrogen. Their hydrogen portfolio includes the massive “Asian Renewable Energy Hub” (AREH) in western Australia. AREH will produce green hydrogen using electricity sourced from wind and solar farms. BP owns 40% of the project, whose total capital cost is estimated at \$50 bn. According to our research, renewable-powered green hydrogen has amongst the lowest EROI of any energy source – far below oil and gas. If we are correct, BP’s \$20 bn investment will yield inferior returns, even worse than those incurred in the rest of their renewable portfolio.

BP invested \$1 bn in multiple US east coast offshore wind projects that may never produce power. For those interested in the recent travails of offshore wind farms, please read the Renewable section of this letter, where we discuss the Commonwealth Wind quagmire off the coast of Martha’s Vineyard.

BP already has a sub-standard return on assets compared with its peers. If they continue with their ambitious renewable plans, their profitability will likely deteriorate significantly from here. BP is a prime example of how renewables impact a company’s profitability. Exxon, Chevron, and Shell should all take notice. An activist shareholder has called for Shell to reduce upstream capital spending further and divert the investment into renewables.

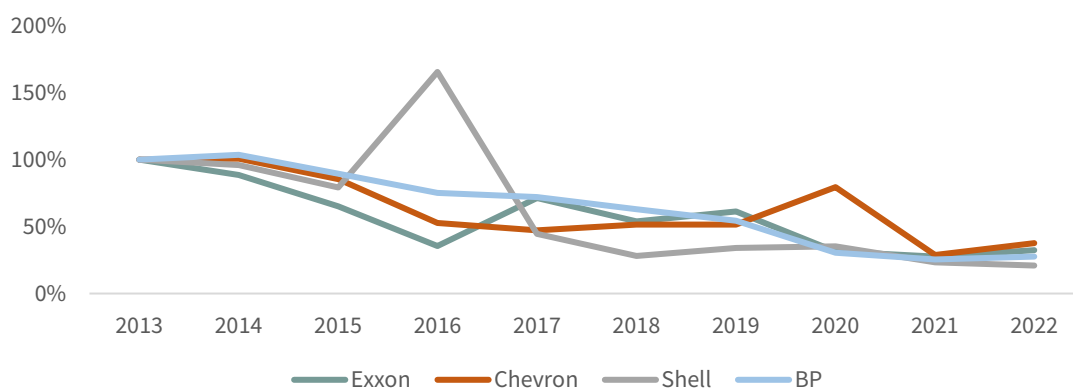
Shell’s underperformance thus far has come from cuts to its highly profitable upstream oil and gas business and not from an increase in renewables. Shrinking production combined with increased renewable investment would likely further hurt earnings and stock performance.

Update on the lack of super-major production growth:

All five companies in our super-major survey increased capital spending and production in 4Q2022. Spending grew 22% compared with 2Q2022 from \$11.1 bn to \$13.6 bn.

Year-over-year, super-major capital spending is up 25%. Increased spending was driven by Chevron (up 37%), Exxon (up 28%), and Shell (up 22%). BP and Total grew their spending much less: 10% and 5%, respectively.

FIGURE 8 Super Major Spending Index (2013=100)

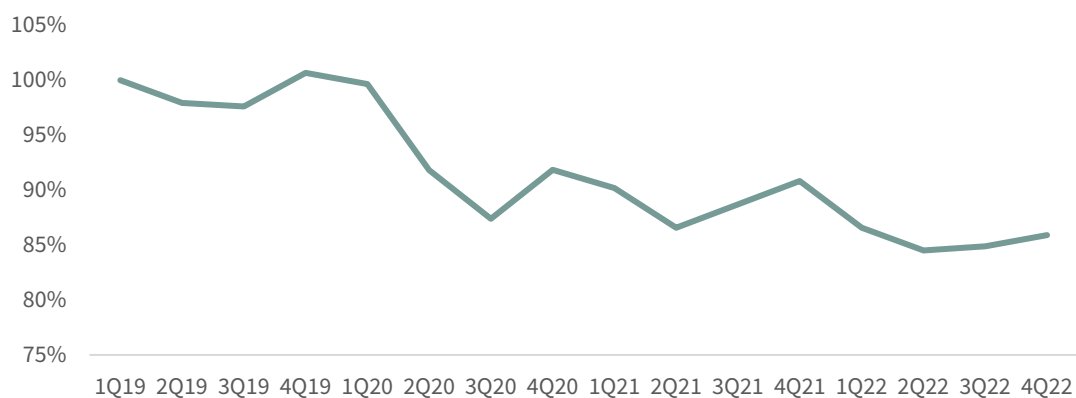


Source: Company Filings, Bloomberg and Company Filings.

Production still has downward momentum. Although liquids production grew 3% sequentially, it remained 1% below the same period in 2021. Total grew the most year-on-year (up 5%), followed by Exxon (up 3%). Chevron and BP saw production fall 4%, while Shell's oil production collapsed 8% year-on-year. On the natural gas side, production continues to slip. Sequential and year-on-year gas production fell 1% and 3%, respectively.

Combined, barrel of oil equivalent (BOE) production is up 1% sequentially but down 3% year-on-year. Since 1Q19, total BOE production has been down a staggering 14%. While downward production momentum may be slowing, the super-majors continue to shrink.

FIGURE 9 Super Major BOE Production



Source: Company Filings, Bloomberg and Company Filings.

Natural Resource Market Commentary: Q4 2022

Commodity prices rebounded in Q4. Natural resource-related equities were firm.

Investors came back into commodity-related markets, hoping that the worst of Central Bank tightening was in the past, combined with economic data that refused to confirm recessionary fears.

The energy-heavy Goldman Sachs Commodity index returned 3.4% in Q4. Reflecting the significant rebound in base metal prices, the metal and agricultural heavy Rogers International Commodity index rose 4.6%. After experiencing some weakness in Q3, natural resource-related stocks showed significant strength in Q4. The energy-heavy S&P North American Natural Resource Stock index rose 17.9%. The S&P Global Natural Resource Index, which has more metal and agricultural exposure, also increased by 18%. In contrast, US equity markets, as measured by the S&P 500 index, rose 7.1%, and global equity markets, as measured by the MSCI All World Index, rose 9.9%. For 2022, commodities and their related stocks significantly outperformed general stock markets. The Goldman Sachs Commodity Index, on a total return basis, returned 25.9%, The Rogers International Commodity index returned 19.8%, the S&P North American Natural Resource stock index returned 33.2%, and the S&P Global Natural Resource index returned 10.2%. In comparison, US equities, as measured by the S&P 500 Index, fell 18.5%, and global stocks, as measured by the MSCI All World Index, fell 17.8%.

Oil Markets

After pulling back a significant 25% in Q3, oil prices stabilized in Q4. West Texas Intermediate crude prices rose 1%. Brent prices were slightly better, rising 2.5%.

Although prices stabilized, investor psychology toward oil remains firmly bearish. Investors remain convinced that an imminent global recession brought on by aggressive Fed tightening is inevitable. The pronounced weakness in 2023 oil demand is consensus opinion.

The gap widens between the “paper” markets and the underlying physical market. In the paper oil markets, speculators have liquidated 125,000 futures contracts on the New York Mercantile Exchange since oil prices peaked back in the first week of March, pushing the oil price down by over \$ 50 per barrel or almost 40%. In contrast, reflecting the strength in global oil demand, global OECD inventories, adjusted for SPR releases, have fallen by another 180 mm barrels—a clear sign of continued market tightness. Now that SPR releases are scheduled to stop (except for another 35 mm barrels related to funding the 2021 Infrastructure and Jobs Act), we believe the deficit between demand and supply and the resulting tightness will be quickly reflected in the oil price.

In this letter's Oil section, we will show that investors are again completely ignoring underlying data. Other than a short-lived period of Chinese demand weakness experienced last summer in one of China's aggressive COVID-related lockdowns, global oil demand continues to surprise the upside. We have significantly passed through 2019 highs in demand. Global inventories, including SPR inventory withdrawals, continue their steep declines and have fallen considerably below their 2007 lows. With lifting all COVID-related restrictions in China, we believe that Chinese oil demand, which now looks to have declined by 800,000 b/d in 2022 versus 2021, could rebound significantly in 2023 and be a driving factor in pushing oil markets into continued deficit.

On the supply side, we will again discuss recent developments in the US shales. After over a decade of phenomenal growth, the US shales continue to expand. The importance of the shales on the global oil balance cannot be overstated. Total non-OPEC supply growth in 2022 should approach 1.9 mm barrels per day, but few people comment on the breakdown of this supply. 80% of the 1.9 mm b/d of growth (1.5 mm b/d) comes from unconventional sources; 1.2 mm b/d from the US shales, 0.16 mm b/d from the Canadian oil sands, and 0.15 mm b/d from biofuels. But what people may miss is that almost 100% of the 1.2 mm/d of US shale growth comes from the Permian Basin. In past letters, we extensively discussed how the other extensive shale basins—the Bakken and the Eagle Ford- peaked and were now in decline and how the Permian only had several years of production growth left. However, more evidence emerged that the Permian is nearing a production peak, possibly in 2024. Drilling productivity increases in the Permian have weakened considerably over the last two years—to the extent that several E&P analysts have commented on the trends. As our readers know, our research tells us that most of the productivity increases over the last decade have come from companies “high-grading” their drilling activity. Declining productivity strongly suggest that companies are running out of tier-one drilling inventory—a classic sign of field exhaustion and a precursor of future production declines. Please read this letter's introduction to learn more. We are reaching a point where we believe almost all non-OPEC oil supply growth will come from just six counties in the Permian basin. Understanding trends in these counties will be vital to understanding the direction of oil prices.

Conventional oil production peaked in the non-OPEC world in 2006 and today sits almost three million barrels below that level. Including OPEC, conventional oil production peaked in 2015 and sits 4 mm barrels lower today. Twenty years ago, a colossal interest developed around the concept of Peak Oil and Hubbert's theories. Since then, interest has switched from peaking supply to peaking demand. We believe US shale oil production is nearing its peak. Given how dismal conventional oil discoveries have been over the last 20 years, we think it's time to bring back the subject of peak oil. If you attended our recent investor day, we continuously stressed that this decade would be the “Decade of Shortages.” Hubbert's peak is a perfect example of what we believe this decade will bring.

Natural Gas

Natural gas pulled back massively. The primary reasons were a significantly warmer-than-normal fall in the US and Europe and a late start to the North American natural gas withdrawal season. US natural gas prices fell 34% in Q4, while European and Asian prices fell 55% and 35%, respectively.

Weather is always a huge factor in the short term. Short-term weather trends produce spasms of price weakness, leading to substantial buying opportunities. We believe the significant price pullback experienced in Q4 today presents investors with another very opportunistic buying opportunity. We are confident that the global natural gas market remains in structural deficit and that the US gas supply, driven over the last decades by considerable expansions in the Marcellus and Hayneville fields, may be ending. When the global markets swung from “structural surplus” to “structural deficit,” international gas prices surged tenfold (from \$6 per MMBtu to \$70 per MMBtu) in just over 12 months. A high probability exists that a move of similar magnitude could happen in the North American gas market in the next 12 months. The Natural Gas section of this letter updates the bullish fundamentals we believe are now fully embedded in the North American natural gas market---bullish fundamentals that short-term bearish weather factors have obscured.

Coal Markets

After experiencing a substantial upward price move in the first three months of 2022, global coal markets pulled back in Q4. Central Appalachian and Illinois prices in the US were flat and down 15%, respectively. Thermal seaborne coal also pulled back in Q4. Thermal coal shipped from Richards Bay, South Africa (the API 2 and API 4 markets) fell by approximately 30%. Thermal coal shipped out of Newcastle, Australia, fell by 7%. Coal was a commodity price leader in 2022-- an exciting outcome given that coal entered 2022 as the world's most hated commodity by far. Even after the Q4 pullback, Central Appalachian coal prices advanced 125%, Illinois basin prices grew 280%, and Australian thermal coal prices advanced 140% for the year. Given the structural tightness in global natural gas markets, we believe global thermal coal prices will continue to rise. We believe radical underinvestment in global coal projects combined with continued energy demand growth means that coal demand will likely continue to set new all-time highs in the next several years. Coal-related equities have been the market leaders in the three great commodity bull markets over the last 120 years (1929-1945, 1970-1980, and 2000-2010). It looks like history is repeating itself.

Base Metals

After experiencing pronounced weakness in Q3, base metals prices staged a significant rebound in Q4, with nickel in the lead based on continued worries over future Russian supply. For the quarter, nickel advanced by 40%, copper increased by 11%, aluminum by 10%, and lead and zinc by 20% and 4%, respectively. Base metals-related equities were also strong. Copper equities, as measured by the COPX ETF, rose 27%, and larger-capitaliza-

tion base metals equities, as measured by the XBM ETF, rose 20%.

In our essay, “The Coming Shortage in Base Metals,” we highlighted how exchange-traded inventories of the six primary base metals—copper, aluminum, nickel, lead, zinc, and tin—now trade at levels last seen in 2005 and 2006. Given the underlying demand strength, driven by China, India, and renewables, along with the severe problems that have crept into the world copper mine supply, copper remains our favorite base metals investment.

In the Copper section of this letter, we discuss the continued unexpected strength in demand and the growing supply problems. Chile supplies 25% of the world’s copper mine supply. Its 2022 copper production has unexpectedly fallen almost 6% versus 2021. Back in the Q1 2021 letter, our introductory essay, “The Problems with Copper Supply,” discussed the operating history of the Escondida copper mine in Chile—by far the world’s largest—which is an excellent example of the enormous problems that are creeping into the world’s copper mining industry. We update what’s happening at Escondida over the two years since and what we believe it means for global copper mine supply from now on.

Agricultural

Grain prices were mixed, and fertilizer prices showed pronounced weakness in Q4. Urea prices slumped 27%, and phosphate and potash fell 18% and 16%, respectively. Q4 was dominated by worries that higher fertilizer prices in the first half of 2022 significantly impacted demand. Nutrien, the world’s largest fertilizer producer, on its Q3 conference call, cut its guidance for potash sales this year on disappointing sales volume. Nutrien said high fertilizer prices and dry North American soil conditions that hindered field fertilizer application significantly impacted demand.

As a result of the worst drought conditions in over 20 years in Argentina, the world’s third-largest soybean producer and the largest exporter of soybean meal and oil, soybean prices advanced 11%. Corn prices in Q4 were flat, and wheat prices fell 14% on news that farmers have significantly boosted their fall wheat plantings.

We believe grain markets will be highly susceptible to any possible black swan events shortly as tightness in the global grain market persists. The recent 175% surge in US egg prices, in response to a tight egg supply and an unexpected “avian bird flu” outbreak, provides an excellent example of a black swan event that could very well grip various agricultural markets as we progress through 2023.

Precious Metals

Precious metals prices finally broke eight months of persistent price weakness and exhibited strength in Q4. After peaking in March, both gold and silver have spent the last eight months declining in response to aggressive monetary tightening by the US Federal Reserve.

Responding to a Fed-Funds rate that has surged to 4.5%, up from zero at the beginning of 2022, gold prices pulled back 20% and silver 35% from their March peaks. Silver prices bottomed in mid-October, and gold prices in early November. In Q4, gold prices rose 10%, and silver prices rose 26%. Gold and silver equities followed the prices of both metals upward. Gold equities, as measured by the GDX ETF, rallied 21%, and silver equities rose 17%, as measured by the SIL ETF.

We believe the two-and-a-half years of price correction in gold and silver prices, which saw gold price fall back 20% and silver prices 40%, has now run its course. After flashing a solid sell signal in the summer of 2020 triggered by silver's furious "catch-up" rally to gold in March to August 2020, we significantly reduced our precious metals equity exposure; however, we believe more evidence has emerged that both gold and silver prices have made their lows in this cycle. Our analysis suggests investors may benefit from increased exposure to precious metals.

Uranium

Uranium markets were quiet in Q4. Spot uranium prices hardly moved, starting and ending the quarter at approximately \$48 per pound. Even though uranium markets were calm, new positive momentum keeps building in the nuclear power generation business. Even Oliver Stone, the famed liberal film director, delivered an impassionate speech at the World Economic Forum (Davos) on how, contrary to standard "green" dogma, nuclear power must be part of the solution to the world's CO2 and climate change problems.

In the Uranium section of this letter, we talk about positive developments. We also discuss the latest news regarding "breakthroughs" surrounding nuclear fusion. On December 13th, a scientist at the Livermore National Laboratory announced they had achieved "fusion ignition"—that is, researchers and scientists were finally able to create a fusion reaction that resulted in a net energy gain. The announcement generated massive excitement; however, the challenges to producing and harnessing energy from a fusion reactor are so incredibly complex we believe that fusion as a power source remains as far away as ever.

Why Oil Markets Will Outperform Expectations in 2023

We believe investors are being far too complacent about oil markets. After making a 14-year high of \$130 per barrel in March, prices have steadily pulled back to \$80. Concerns around the security of supply following Russia's invasion of Ukraine have given way to worries about recession and sagging demand. Oil has nearly given back its entire move higher since the attack took place on February 24th, 2022.

Demand fears are misplaced; we believe supply issues will drive the oil market for the foreseeable future. Crude demand has proved far more resilient than most analysts have expected for nearly two decades. For example, economic activity slowed following the 1980 oil price spike, and demand fell almost 10%. It took nearly ten years for demand to surpass the 1980

peak. On the other hand, economic activity plummeted following the 2008 price spike and the global financial crisis. Instead of falling by 10% (or even more), crude demand fell by only 1.5%, surpassing the 2007 peak in 2010. The difference was that in 1980, OECD countries made up 68% of global oil demand, whereas by 2010 it was only half. Emerging markets have a much different price elasticity and demand profile than developed countries: consumption is far more resilient. More recently, during COVID, energy analysts argued vociferously that global demand would never again regain 2019 levels. Less than three years later, the International Energy Agency (IEA) expects 2023 demand will be 1.4 m b/d greater than in 2019. In our view, the old energy demand models, centered on developed country trends, no longer apply.

On the other hand, investment drives supply, which remains extremely low. Between 2014 and 2019, global upstream E&P spending fell by one-third from \$900 bn to \$600 bn. COVID slashed budgets further, and they have not recovered. The IEA estimates that by 2022, spending was down by another 30% compared with 2019 to only slightly more than \$400 bn. We believe this is not enough. We have starved this industry for capital for eight consecutive years and are feeling the effects. We believe the energy crisis will only improve once the sector increases spending. Based on recent announcements, no material increase in spending is in sight.

This past year marked the second consecutive year of oil inventory draws. Since December 2020, global stockpiles have collapsed by 600 mm bbl – eclipsing the previous record set in 1999/2000 by 2.5 times. All indications point to an unprecedented third year of inventory draws in 2023. Stockpiles stand at four bn bbl – a level last seen in 2003. If our models are correct, inventories could end the year at 3.2 bn bbl, the lowest reading since 1986.

Somehow, after nearly three years of oil market tightness and two years of strong equity performance, investors still refuse to allocate capital to the space. Over the last two years, energy has outperformed any other sector in the S&P 500 by 130 percentage points and the index by 150 percentage points. And yet, energy still represents less than 5% of the S&P500's market capitalization – less than half its long-term average and 65% below the 2008 peak.

Has the two-year rally finally started to convince investors? Quite the opposite: since mid-2021, investors withdrew billions from the largest energy-equity-related ETFs -- the XOP and XLE. Over that period, the XLE (which tracks large energy companies) generated a total return of 72% while the XOP (which tracks independent E&Ps) advanced 45%, compared with the S&P 500 as a whole, which fell 1.6%. Despite the strong outperformance, the XLE saw \$1.3 bn in net outflows over the period, while the XOP saw \$1.8 bn in net outflows. Over \$1 bn of the combined net outflows occurred this year alone. Last year, we estimated energy companies generated 35% of the entire cash flow of the S&P 500 despite being less than 5% of the index's market capitalization; the relentless liquidation continues. Is it possible that energy executives are not keen to grow their assets when investor sentiment remains bearish?

Investor interest aside, oil market fundamentals remain extremely strong. Although demand was weaker than expected in Q4, our models suggest warm weather was a key factor. Following Russia's invasion of Ukraine, European policymakers dramatically switched from natural gas to help replenish stockpiles ahead of the winter. While coal and biomass were the primary beneficiaries, oil demand increased. As gas inventories grew and the winter proved warmer than expected, this crude demand fell. Some crude demand destruction likely took place, notably for gasoline and diesel. When West Texas Intermediate crude prices reached \$122 per barrel in June, refined product prices exceeded \$170 per barrel as refining bottlenecks caused crack spreads to expand dramatically.

Despite weaker-than-expected second-half demand, we estimate that global oil markets were in structural deficit by as much as 500,000 b/d throughout 2022. Furthermore, our models tell us this deficit will worsen as we progress through 2023. In their latest Oil Market Report, the IEA implies that oil markets will be in deficit by as much as 600,000 b/d this year. It is infrequent for the IEA to predict a deficit; typically, their estimates skew toward a surplus. We cannot recall any other time, under normal market conditions, when the IEA predicted a large deficit.

Our models tell us the deficit could be even more extreme. The IEA estimates that demand will grow by 1.9 m b/d, reaching 101.9 in 2023. However, several adjustments are necessary. First, the IEA has "missing barrels" in its balance sheet. As long-time readers recall, "missing barrels" occur when, according to the IEA, companies produce oil that is neither consumed nor added to storage. The result is a "miscellaneous to balance" line item on their balance sheet that we refer to as the "missing barrels." In reality, this oil is not missing but almost always signals forthcoming upwards revisions to demand. In 2022, the "missing barrels" ran at 300,000 b/d, including a massive 700,000 b/d figure in Q4. Assuming that the "missing barrels" are underreported demand, 2023 consumption could reach 102.2 m b/d. Chinese demand could also be higher than expected.

The IEA predicts their consumption will grow by 900,000 b/d to reach 15.9 m b/d. Although this sounds like impressive growth, they are likely understating demand given how dramatically COVID-zero policies impacted 2022 figures. We estimate last year's lockdowns moved demand by 1.5 m b/d for at least seven months. Over the entire year, this lowered demand by 850,000 b/d, making this year's 900,000 b/d growth seem far too low. Once the rest of the world came out of the COVID lockdown, consumption surged due to pent-up demand. Although this snap-back eventually moderated, Chinese demand could grow far more than expectations for at least the next six months. Analysts are taking for granted that the world's second-largest oil consumer has let its 1.3 bn population out of lockdown. The impacts could be massive.

We also believe that China will soon begin a period of sizable stimulus to help assuage the

public's discontent following two years of restrictive lockdowns and weak economic growth. We believe Chinese oil demand can conservatively run 450,000 b/d ahead of expectations, taking global consumption to an astounding 102.7 m b/d.

On the supply side, the IEA expects non-OPEC+ supply growth of 1.8 m b/d, split almost evenly between the US and the rest of the non-OPEC+ world. Compared with Q4 production, the report implies that full-year US production will average 400,000 b/d ahead of the Q4 2022 supply. While this number may be high, we believe it is in the right ballpark. The IEA expects non-OPEC+ outside the US to average 600,000 b/d ahead of Q4 2022 figure, which we think is too high by half.

The IEA projects OPEC+ production will fall 600,000 b/d year-on-year to average 51.5 m b/d – more than 1 mm b/d below the Q4 2022 reading. This figure assumes Russian production will fall by 1.2 m b/d year-over-year compared with Q4 2022. The truth is that neither Goehring & Rozenwajg nor the IEA can know with any certainty. Russia has already announced a 500,000 b/d production cut in retaliation against the NATO-led \$60 price cap. While some pundits have argued that this cut signals unsold crude, we believe it may signal field fatigue instead.

Between 2010 and 2012, Russia drilled, on average, 16,000 km of new oil wells per year, resulting in annual net production growth of 170,000 b/d. Drilling increased by 65% to 26,500 km per year in 2021 and 2022, but annual net production growth fell slightly to 165,000 b/d. We estimate the average kilometer of new drilling went from bringing on 70 b/d per km to 40 b/d – a fall of nearly 40% over a decade. Since most Western oil field service companies have left the country, drilling productivity will likely fall more. For those interested in a much more in-depth discussion on the Russian oil industry and its reserve replacement problems, please refer to our Q4 2021 letter, “The OPEC Spare Capacity Issue Part 1: The Russian Dilemma.”

According to the IEA's base case figures, 2022 will be in deficit by 600,000 b/d. Adjusting for the “missing barrels” and pent-up Chinese demand, we believe the deficit could widen to 1.4 m b/d, leaving inventories at four-decade lows by the end of the year.

Investors are focusing on all of the wrong things. Stories of a near-term energy glut dominate headlines. Near-term demand is always noisy and prone to reversion. Longer-term, we believe the oil market will be dominated by the massive lack of upstream capital spending that has been chronic for nearly a decade. We expect the ongoing energy crisis will persist until investors regain interest in conventional energy and encourage companies to drill. There will be volatility, as always; however, we believe crude prices are headed much higher.

Weather Presents a Natural Gas Buying Opportunity

Our Q122 letter explained why North American natural gas prices would surge. After making a 25-year low of \$1.48 per mcf in June 2020, Henry Hub gas broke \$7.00 in Spring 2022 for the first time in 14 years. International gas prices were even more substantial. Driven by Russia's invasion of Ukraine, European LNG import prices spiked to \$70 per mcf in March before settling back around \$35 per mcf, a multi-year high. We argued that North American prices would converge over time with seaborne LNG prices, with dramatic bullish consequences.

Gas prices did rally sharply in the months following our letter. Henry Hub natural gas reached a high of \$9.68 per mmcf, and European prices reached an astounding \$91.02 per mcf in August 2022 following hot weather and increased hostilities in Ukraine. Since then, however, prices have collapsed. As we write, North American and international prices are the lowest since mid-2021, more than giving up the gains since the Russian invasion.

What's behind this collapse, and what does it mean going forward? Despite the considerable pullback, our thesis has not changed: we believe both US and global natural markets are in structural deficit. As you will see, we believe all weakness is due to one-off factors and should not repeat themselves. The underlying fundamentals remain incredibly tight, and we believe the current weakness presents long-term investors with an extremely attractive opportunity.

While our natural gas equity investments were down, they held in much better than the commodity. From the August 2022 high point until the end of January 2023, North American gas fell 71%, while imported European LNG fell 80%. Our natural-gas-focused equities, meanwhile, fell much less, selling off between 27 and 34%.

Although global gas markets remain in a long-term structural deficit, the supply and demand fundamentals did loosen on a short-term basis compared to last spring. In the US, curtailed LNG export capacity following the Freeport fire drove the loosening. In Europe, the market loosened dramatically due to much milder than typical winter weather. Both of these factors were one-time and are unlikely to repeat going forward.

Starting with the US, inventories were 300 bcf below long-term seasonal averages at the end of last March. On June 8th, 2022, a fire broke out at the Freeport LNG export terminal in Texas, leaving the facility completely inoperable. Between June 8th, 2022, and January 31st, 2023, Freeport lost two bcf/d of exports or 474 bcf of total demand. The onset of winter provided little relief. After a slow start to winter in November and early December, temperatures dropped into the year-end. Warm weather returned in January, so by the end of the month, total winter heating degree days were 5% below average, reducing demand by another 30 bcf in aggregate. By the end of January, the storage deficit had been completely repaired,

with inventories at 2.4 tcf, precisely in line with long-term seasonal averages. The lost exports from Freeport's closure and the mild weather increased inventories by over 500 bcf, with the vast majority of the impact coming from Freeport. Without these two factors, inventories would have ended January at 1.8 tcf, which would have been the lowest level in twenty years. On February 13th, Freeport announced its first vessel loading since last June, suggesting the most significant impacts of the fire are behind us.

Mild weather dominated European gas markets. Last March, European gas inventories stood at 1.1 tcf, nearly 475 bcf below five-year seasonal averages and the lowest March reading since 2018. On February 24th, Russia invaded Ukraine, severely risking the European gas supply. Russia has made up 55% of European gas imports in recent years, representing one-third of total demand. European leaders immediately took drastic measures, increasing LNG imports, curtailing industrial production, and switching to coal and biomass wherever possible. What is not widely appreciated, however, is that through May, Russian pipeline imports continued, albeit at somewhat lower rates. The European strategy worked, and by the end of October, inventories had gone from a 475 bcf deficit to a 150 bcf surplus. Over the summer, European stockpiles grew by 2.6 tcf -- 30% or 620 bcf more than the average summer build, despite the Russian disruption.

Mercifully, the current winter has been the mildest in recent history. The European heating degree days through January 31st are likely 15% below five-year averages, which reduced natural gas demand by an astonishing four bcf/d or 500 bcf over the four months. Continued industrial curtailment and gas-to-coal switching likely reduced demand by another two bcf/d or 250 bcf. Reduced demand, thankfully, more than offset lost Russian volumes. Although the final data is not yet available, preliminary estimates suggest that European inventories fell by only 860 bcf, 40% between October and January, or 570 bcf less than average.

As a result of warm winter and extreme policy measures, Europe ended January with 2.9 tcf of gas in storage, tied for the highest level in over a decade.

A lucky combination of export outages, tough choices, and warm weather helped repair the inventory situation in the United States and Europe. However, we believe long-term structural problems loom large on the horizon. The Freeport LNG facility looks to be back online, increasing US export demand by two bcf/d. In Europe, the extremely warm winter offered a reprieve; however, policymakers must now figure out how to permanently replace 18 bcf/d of Russian imports, equating to one-third of total demand. There are no easy solutions. Global LNG volumes total 52 bcf/d, so the seaborne market can only replace Russian pipeline imports for a while.

Moreover, given their climate goals, it seems unlikely Europe will accept burning record levels of coal on an ongoing basis. Although pundits are pushing for increased renewable penetration, there is a growing realization that underperforming wind and solar assets

throughout Europe have increased reliance on Russian gas in recent years as a backup. As the immediate threat of winter recedes, many Europeans face the daunting task of adjusting to the new energy reality.

In the United States, falling natural gas prices have led to a misguided sense that the worst is behind us. Over the past twelve months, Americans, in general, have felt a sense of remove from the gas crisis facing Europe. We argued that would soon change as US prices became locked into global prices through increased LNG exports. Today, the prevailing wisdom says this will not become a problem until 2025 when the next tranche of LNG export capacity comes online.

We disagree. We believe the US market could slip into deficit much sooner.

Since June, the US gas market would have been in deficit had it not been for the Freeport outage. With that facility now online, we expect balances will tighten. As Calcasieu Pass brings on its new terminal, nearly one bcf/d of additional export capacity will come online later this year. Next year, 3 and 3.5 bcf/d of new capacity will come online, followed by another 2 - 2.5 bcf/d in 2025. In total, 5.7 - 6.5 bcf of additional LNG export volumes will be online between now and the end of 2025 on top of the two bcf/d from Freeport restarting. Who will provide this new gas?

Over the past twelve months, US dry gas production grew by three bcf/d; however, we believe this will slow dramatically going forward. We argued in our previous letters that the Marcellus was nearing its plateau, while the Haynesville may enjoy one or two more years of growth before rolling over. Nothing we have seen has changed our view.

Since 2012, total dry gas production has surged by 50% or 34 bcf/d. Over half of this increase came from the Marcellus, with another 40% from the Permian. Less than 10% or 350 mmcf/d per year came from all the other plays combined, including the Haynesville. As discussed in our introduction, our models tell us that the days of prodigious Permian growth are behind us. The Marcellus, meanwhile, is following our prediction, with de minimis growth in two years. Production appears stuck around 25-26 bcf/d, a level reached in late 2020. Over the last twelve months, the Marcellus has declined by 300 mmcf/d. The Haynesville has been a bright spot, growing by two bcf/d in the previous twelve months. While our models suggest that the Haynesville can still increase from here, we believe production will plateau as soon as next year. The Haynesville is a costly play due to its high pressure, temperature, and formidable depths exceeding 13,000 ft. At today's gas prices, most of the play is uneconomic. The rig count in the Haynesville peaked last September, with gas at \$9 per mcf, and has fallen after that.

When we laid out our case for much higher gas prices last May, we warned that weather is

always the wildcard. Luckily for Europe, the weather turned very favorable. However, we cannot take that for granted. The natural gas market remains exceptionally tight after a decade-long grueling bear market dramatically starved the industry of much-needed capital. The recent weakness should prove temporary. Natural gas equities, meanwhile, represent extreme value in our view. With many gas producers having reported earnings, we can analyze their SEC PV10 values. Using the average of last year's gas prices, Range Resources announced a PV-10 of \$29.6 billion, or \$113 per share, after adjusting for the debt – four times today's stock price. Even using forward strip pricing of ~\$4.25 per mcf, the debt-adjusted PV10 is \$52 per share – twice today's price. EQT resources has a debt-adjusted PV10 of \$127 on last year's gas prices and \$65 using the forward strip – again four times and twice today's stock price, respectively. Antero has not yet released its SEC PV10 value, although we expect it will be as impressive.

The weather has substantially contributed to lower natural gas prices in the US and Europe. We believe the weather-induced price weakness is a short-term anomaly in a longer-term supply deficit story.

Base Metals: A Decade of Shortages Ahead

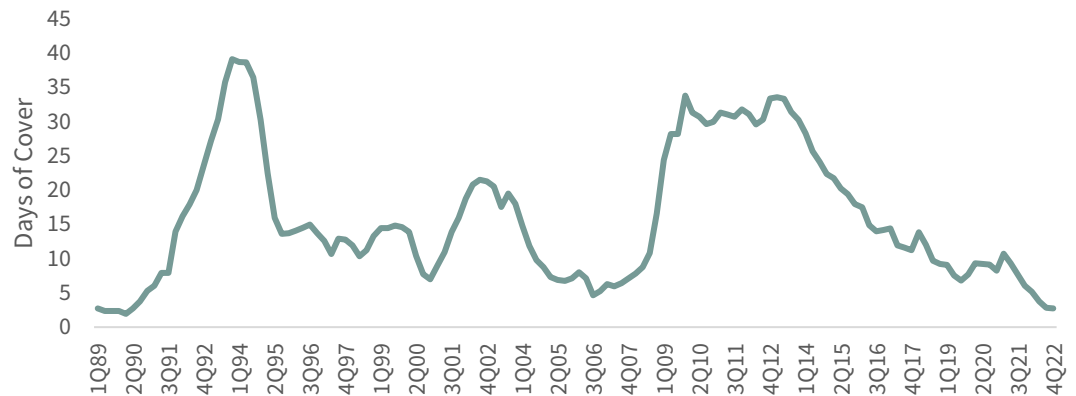
“The Decade of Shortages” was the unofficial theme for our investor day, held on November 3rd, 2022. Our audience heard presentations from five guest speakers and the two eponymous partners, outlining fundamental trends in various commodity markets that confirm our thesis. We discussed how we believe the shortages in the first two years of this decade were destined to be repeated multiple times in different commodity markets as we progressed through the remaining years. ESG pressures have forced significant redirection of capital spending away from extraction industries to renewable projects, shifts in global power from unipolar to multipolar, war, supply-chain breakdowns, changing weather patterns, and underappreciated shifts taking place in the geology or extractive industries — all were discussed as well their supply impacts on various commodities.

What was not discussed at our conference is a great shortage we believe is in the making.

Although the global mining industry, over the last decade, has been able to side-step most of the negative publicity that has engulfed the world oil and gas industry, ESG pressures have placed substantial downward pressures on global mining industry capital expenditures in the last ten years. Environmental and related permitting issues have made both greenfield and brownfield mine development projects extremely difficult to bring into production. Given the vast ESG-related restrictions put on mining projects today, it is not uncommon that significant, economically robust discoveries made over 20 years ago are still not in production today. In a world where metal demand is already beginning to see substantial

accelerations—ironically because of ESG-inspired environmental pressure - mine supply has, for many years, started to fall behind demand. If metal demand exceeds supply on a sustained basis, then metal held in quickly mobilized inventory should decline, which has transpired. Below is a chart showing the base metals inventories held at the three big metal trading exchanges: the London Metals Exchange (LME), the New York Metals Exchange (COMEX), and the Shanghai Metal Exchange.

FIGURE 10 Base Metal Inventories as Days of Cover



Source: Bloomberg.

Since peaking at 9 mm tonnes of inventory in Q1 2013, base metals inventories have drawn steadily and are down 90% today. Today, exchange inventories have fallen below 1 mm tonnes and are dangerously low. Adjusted for days of consumption, inventories have never been lower. In Q4 2022, exchange metal inventory covered daily consumption by only 2.7 days, surpassing 45% of the lows seen in 2005-2006 of approximately five days and reaching the lows seen 35 years ago back in 1988-1989.

The late 1980s saw robust base metals demand as the global economy boomed and Japan seemed destined for world economic domination. In response to inventory tightness, from 1988 to 1990, zinc prices surged 230%, copper rose 175%, and nickel prices skyrocketed 700%. However, the tightness in base metals inventories and the enormous upward pressure in prices were short-lived. The implosion of the Former Soviet Union (FSU) began in 1990, which significantly impacted the base metals supply fundamentals for over a decade. The FSU’s military-industrial complex, an incredibly intense and inefficient user of base metal, collapsed post-1990, flooding the West with new supply. After 70 years of communism, the FSU had become a massive base metals junkyard, and all this scrap added to the flood of supply headed west. Also contributing to the global inventory build post-1990 in base metals was the “popping” of the Japanese financial bubble. Japan became one of the world’s largest consumers of base metals from 1960 through 1980. The economic crisis, which eventually produced Japan’s lost decade, severely impacted their metals demand.

The flood of excess FSU supply and the easing of Japanese demand can be seen in the chart above. By 1993-1994, the days of demand cover of exchange inventories had soared to almost 5 mm tonnes, representing nearly 40 days of consumption, a level never seen since. Excess

base metals inventories significantly contributed to the second leg of the significant commodity price bear market, stretching 20 years—from 1980 to 2000.

It took the next 15 years to work this excess inventory off, but surging China metal demand by the mid-2000s again drew base metal inventory levels back to dangerously low levels. In 2006 exchange inventories fell to briefly 1 mm tonnes, and when adjusted by days of consumption, inventories had fallen to less than five days of consumption—the lowest levels since 1990. And just like in the late 1980s, base metals prices experienced a massive surge. From the end of 2004 to the beginning of 2006, copper, nickel, lead, and zinc prices surged between 300% and 400%.

High base metal prices kicked off a new mine investment cycle. The increase in base metal mine supply, combined with the 2008-2009 financial crisis and slower increases in Chinese base metals demand, caused the inventory pressure in base metals markets to increase markedly. Between 2010 and 2015, exchange inventories, when adjusted for consumption, had risen to levels not seen since the early 1990s.

Today with exchange inventories sitting slightly below 1 mm tonnes, these inventories cover only 2.7 days of consumption.

In global base metals markets, we are well past the former tightness levels experienced in 2005 and 2006. Given the strength of worldwide demand and supply constraints, we believe it's only a matter of time before shortages in various metals reach detectable levels, with potentially tremendous resulting upward price pressure.

Investors over the last year have become convinced the world will become gripped by several global recessions, driven by rising interest rates and continued real estate-related problems in China—both of which will produce noticeable impacts on global base metals demand. However, investors are missing the vast new sources of demand now embedded in international base metals demand figures.

In previous letters, we have stressed how metal intensive the coming renewable power investment cycle will be. Last summer, S&P Global's Commodity Insights paper "The Future of Copper: Will the looming supply gap short-circuit the energy transition?" received significant press attention. The study warned of an "unprecedented and untenable" copper shortfall of 10 mm tonnes as suppliers grapple with copper demand that will double by 2035. We believe³ even S&P's "pessimistic" copper supply outlook is still too optimistic.

For years, we have been warning that copper was slipping into a "structural deficit." The S&P study confirms this—including the under-appreciated copper metal intensity of renewable investment. Given that inventory of exchange copper adjusted for consumption has now

reached the record low levels of 1990 and 2005 and that we are only now seeing the structural gap emerge between copper demand and supply, we believe that the copper market will become the first base metals market to display severe shortage characteristics.

We believe this is going to be the decade of shortage across multiple commodity markets. Base metals markets give investors a great example of what a looming base metals shortage looks like. We find it fascinating that investors are paying no attention to base metals inventories that have reached record lows.

The Price Tag on Renewable Subsidies: The Inflation Reduction Act's Mal-Investment of Trillions

Analysts constantly state that renewable energy competes favorably against natural gas and coal-fired electricity generation on an unsubsidized basis. Although we disagree with this assessment, particularly once you adjust for intermittency, reporters repeat it headline after headline. Given the alleged cost benefits, we cannot help but wonder why policymakers continue to announce hundreds of billions of dollars in new renewable subsidies. Presumably, given ever-growing budget deficits and concerns around debt ceilings, we should be lessening the subsidies on wind and solar if they are cheaper than traditional power sources.

Instead, the Inflation Reduction Act of 2022 includes the most significant renewable power subsidies in history:

1. An investment tax credit refunds up to 50% of the capital costs of wind and solar power. This tax credit is in effect until 2032 or until the US reduces its carbon emissions from electricity by 75% -- a herculean goal that guarantees the subsidies will persist for decades.
2. The tax credit is uncapped: if power producers install new renewable capacity faster than expected, the impact of the Act will be more significant than budgeted.
3. A production tax credit of 2.6 cents per kilowatt hour (kwh).

The Energy Information Agency (EIA) claims incremental onshore wind costs between 2-6 cents per kWh on a levelized cost of electricity basis, while solar's LCOE is 3-5 cents per kWh. Therefore, the production tax credit equates to 30-100% of the total cost.

Combining the investment tax credit with the production tax credit, the cost of renewable power can turn negative. Our research tells us these credits may represent the largest mal-investment of capital in history.

Pundits argue these subsidies will help accelerate the transition from hydrocarbons; we remain skeptical. Throughout human history, society has willingly shifted away from one form of energy towards another only when it has been economically advantageous. Before Colonel Drake drilled the first oil well in 1859, whale oil was a dominant fuel source. In 1840, the US consumed 1.6 PJ of whale oil, equivalent to 710 barrels of crude oil equivalent per day. By 1870, whale oil consumption had fallen 75% to only 175 barrels of oil equivalent per day, while crude demand surged from nothing to 14,000 barrels per day. The economics of drilling and burning crude oil justified the transition. Society did not rely upon subsidies. Instead, economics and energy return on investment (EROI) drove the adoption. Our research shows that fully buffered renewable power has a much lower EROI than natural gas. By massively incentivizing the widespread installation of such an inferior energy source, the Inflation Reduction Act will ultimately usher in an energy crisis of unprecedented magnitude.

Many analysts quickly point out that the cost of wind and solar have fallen by 80-90% over the past decade. They argue that these massive cost reductions are evidence of a sharp “learning curve.” As the industry installs more renewable power, they claim, efficiencies grow, and costs fall. According to this logic, governments should heavily subsidize early renewable capacity to reduce costs and fast-track adoption.

Unfortunately, our research suggests that this strategy relies upon a faulty assumption. Over the past decade, most of the cost savings have come from cheap capital and energy costs and not dramatically improved manufacturing efficiency.

The 2010s were unique for two reasons: most primary energy sources fell by 90% from peak to trough, and the cost of capital turned negative for the first time in human history. Renewables are much more energy and capital-intensive than coal and natural gas-fired electricity generation. Is it any wonder their costs fell dramatically over the same period?

An efficient natural gas plant achieves an EROI of 30:1 after accounting for the energy needed to drill, lay pipelines, build the plant, and burn the gas. On the other hand, a top-performing onshore wind turbine is lucky to achieve an EROI of 12:1, while high-quality solar’s EROI is 8:1. These figures are on an “unbuffered” basis, meaning they do not adjust for renewable power’s intermittency. Utilities must install massive battery backups if they use wind and solar for base-load power. These batteries are very energy intensive to manufacture, lowering the buffered EROI to 6:1 and 2:1 for wind and solar, respectively. Therefore, it requires between 4 and 14 times more energy to generate a kWh of electricity on a buffered basis with renewables than with natural gas.

How do interest rates impact renewables? The levelized cost of electricity -- the most widely used energy cost metric -- is calculated by dividing the present value of all capital and operating expenses by the present value of all electricity output in kWh. While applying a

time value of money to the electrical output might sound strange, this is how analysts calculate LCOE.

For wind and solar, capital expenditures make up 90% of the total undiscounted cost, whereas operating expenses make up 95% of the total for a natural gas plant. In both cases, electricity output is flat over time. Therefore, with renewable energy, as interest rates fall, the present value of the capital cost remains unchanged while the present value of the output, discounted at a lower rate, grows. In the case of natural gas, the present value of the operating costs rises at the same rate as the present value of the output, leaving the ratio unchanged. A 600 bps fall in interest rates, experienced between 2010 and 2020, resulted in a 40% reduction in renewable LCOE but only a 4% reduction for natural gas. Conversely, renewable LCOE will grow much faster as interest rates rise.

We estimate that 65% of the reduction in wind and solar costs between 2010 and 2020 can be attributed to lower energy costs and falling interest rates. The “learning curve” explains only one-third of the observed decrease. If our models are correct, subsidizing wind and solar to help push costs further down the learning curve will be more than offset by rising energy and capital costs.

In Q4 2021, we predicted that rising energy and interest rates would drive renewable costs much higher. Less than two years later, we are already seeing the effects.

In early 2022, the Commonwealth Wind project (a 1,200 MW proposed wind farm off the coast of Massachusetts) signed an agreement with the Department of Public Utilities to provide electricity to the Boston area. Less than six months later, Avangrid Renewables (the project sponsor) announced that the “project [was] no longer viable and would not be able to move forward” without renegotiating their contract. The company blamed rising input and capital costs. In a matter-of-fact statement, in late January 2023, the company announced that the project “cannot be financed and built.”

In February, Duke Energy Corp. announced they would take a \$1.3 bn impairment loss on selling their commercial renewables portfolio – a reduction of nearly 50%. When asked if they had overvalued their assets, the company replied: “I wouldn’t call it overvaluing. If you decide to sell these assets at any point in their life, you’re setting yourself up for an impairment.” Dominion Energy Inc. announced a \$1.5 bn impairment charge on their 1,000 MW solar portfolio the same week.

Also, in February, BP announced it would slow its renewable transition pace after years of being the most vocal renewable supporter. On their Q4 earnings call, CEO Bernard Looney admitted that his renewable portfolio generated only a 6-8% margin compared with 20% for oil and gas investments. Shell made similar comments shortly after.

As energy prices and interest rates continue to climb, we believe many similar announcements will follow.

How can the industry explain all of these write-offs and about-faces if, as is widely stated, renewables are far more economical on an unsubsidized basis?

In our view, renewables can only work with abundant cheap energy and near-free capital. Unfortunately, a lack of upstream investment and persistent inflation means neither will be available. Nevertheless, policymakers insist on subsidizing more than 100% of the cost of renewable energy, a price tag of trillions of dollars. The result may be the largest mal-investment in human history. The vast energy disruptions and dislocations in Europe today provide a “road map” of what will happen here in the United States.

We estimate that over the next 15 years, the Inflation Reduction Act’s investment and production tax credits could total over \$1.5 trillion. Unfortunately, we expect much less energy will be available in the US. Consider the following. If you believe we are now in an energy-insecure world, there are two available power technologies: natural gas or coal and renewables. The former enjoys an EROI of 30:1, while the latter has an EROI of ~5:1. The IRA has now guaranteed that investors will divert capital from traditional energy to renewable power. We believe the net result will, of course, be much less available energy, severely limiting economic growth.

Nor do we expect renewable subsidies will limit CO2 emissions. Germany has had the world’s most ambitious renewable subsidy program to date. Unfortunately, the renewable capacity has underperformed expectations over the past several years. As a result, Germany had to rely increasingly upon Russian gas imports. Following Russia’s invasion of Ukraine, Germany was forced to turn to coal to meet its power needs, completely undoing 20 years and trillions of dollars’ worth of renewable subsidies. We believe German coal-burning reached a record in 2022, resulting in CO2 emissions not seen for over a decade. While some might argue this was only due to the Russian invasion, poor energy policy played a determining role.

A viable solution exists today in the form of nuclear fission. Generation IV nuclear plants offer EROIs over 180:1 – far superior to renewables and traditional energy. Furthermore, nuclear fission emits no carbon at all. While the IRA offers some nuclear power credits, it does not go far enough.

The cost overruns and write-downs in the renewable space are just the beginning. Until policymakers can understand the issues in terms of EROI, they will continue to tilt at proverbial and literal windmills.

Nuclear Fusion? Not so Fast

On December 13th, 2022, the U.S. Department of Energy (DOE) announced a nuclear fusion breakthrough. For the first time in history, scientists at the Lawrence Livermore National Laboratory achieved fusion “net energy gain,” releasing more energy than was consumed in the reaction. Immediately, journalists wrote near-utopian articles describing imminent abundant clean energy. Jennifer Granholm, US energy secretary, summed up the excitement: “This milestone moves us one significant step closer to the possibility of zero carbon abundance fusion energy powering our society.”

Unfortunately, our research shows that the likelihood of nuclear fusion’s usable power remains extremely low.

There are two “nuclear” reactions: fission and fusion. During a fission reaction, the nucleus of significant, heavy elements (notably uranium) breaks apart into lighter elements. During the transformation, elemental mass converts into energy per Einstein’s famous $E=MC^2$ equation. Only a specific rare uranium isotope (U235) is prone to spontaneous nuclear fission; if all uranium underwent fission, none would remain on Earth. The key to creating a fission chain reaction is to enrich natural uranium from 0.05% U235 by mass to 5-7%. Under particular circumstances, fuel rods of low-enriched uranium will see some of its U235 isotopes undergo fission, releasing energy from neutrons. These neutrons will lead to further fission reactions in nearby uranium atoms: a chain reaction.

The energy released during this chain reaction is absorbed (presently using high-pressure water and soon using molten salt) and used to spin a turbine and generate electricity. The reaction’s heat tends to be between 300-500 degrees Celsius. By varying the degree of enrichment, and the physical configuration, a fission reaction can either fizzle out, maintain a steady-state chain reaction (nuclear power reactor), or generate a super-critical uncontrolled energy release (an atomic bomb). Uncontrolled fission was first demonstrated at the Los Alamos test facility in New Mexico as part of the Manhattan Project with the Trinity Test in 1945. Controlled fission first generated power in 1951 at EBR-I in Idaho and has been used ever since.

Fusion, on the other hand, is a much more complicated reaction. Under the right circumstances, very light atoms (usually two specific hydrogen isotopes) fuse to create a heavier atom, releasing prodigious amounts of energy. Under normal circumstances, ions (atoms stripped of their electrons) repel each other. Extremely high temperatures and pressures (typically only found in stars) are necessary to overcome the repelling forces that prevent atoms from fusing.

The detonation of Ivy Mike – the world’s first thermonuclear hydrogen bomb - successfully demonstrated runaway fusion in 1952. An atomic bomb generated enough energy to create

the extreme temperatures and pressures needed to allow for the fusion of deuterium and tritium (isotopes of hydrogen and lithium, respectively).

As early as 1956, scientists hoped to harness nuclear fusion for helpful power production. However, while fission took six years from initial uncontrolled reaction to an early power station, controlled fusion has proved much more elusive.

The challenge comes from the extreme operating conditions, namely the temperature, and pressure. The Lawson Criterion maps the so-called “triple product,” or combinations of temperature, pressure, and time that will result in the fusion of two atoms. There have been several approaches to fusion, all of which involve extreme temperatures or pressures. The time element has been the most challenging considering the difficulties in maintaining extreme temperature and pressure over anything but minor time intervals.

In the seventy years since Ivy Mike proved nuclear fusion was possible, overcoming the Lawson Criterion to create a sustained fusion reaction has been impossible.

A critical element of a sustained reaction is the “Q” factor which measures how much energy the fusion reaction releases compared with how much energy it consumes to create the appropriate conditions (high temperature and pressure). Until late last year, no reactor had ever had a Q-factor greater than one – i.e., more energy released than consumed. In a widely heralded event last December, Lawrence Livermore’s National Ignition Facility (NIF) announced it had finally broken the elusive barrier, achieving a Q-factor of ~1.5x.

While the media was keen to push the breakthrough as “game-changing,” a closer analysis revealed many remaining challenges. First, the Q-factor was somewhat misleading to a non-scientific audience. The NIF’s laser generated a pulse that delivered 2.05 MJ of energy into a fuel pellet 1 cm in diameter. The energy immediately stripped the fuel of its electrons and heated the ions to an internal temperature of three million degrees, which precipitated the fusion reaction. The reaction released 3.15 MJ of energy, resulting in a Q-factor of 1.5x. However, the laser consumed nearly 300 MJ of energy, suggesting the reaction consumed ~100 times as much energy as it released. Moreover, the reaction lasted less than one-billionth of a second. To create electricity, the reaction must run continuously -- firing 846,000 times daily.

Theoretically, a Q-factor greater than one could lead to “ignition,” where the energy released is enough to allow additional fusion in a sustained chain reaction, similar to fission. The difference is that fission chain reactions are largely passive: fuel rods undergo sustained fission once inserted with little intervention. Generating the 1.15 MJ of net energy gain with fusion (enough to power a toaster for 15 minutes) required the precise placement of 192 large lasers focusing their output on a hyper-polished pellet less than 1 cm in diameter. The likelihood of sustained chain-reaction fusion is not practical.

Many journalists pointed out that even if December's breakthrough was not yet "ready for prime time," it proved that fusion's widespread adoption was only a matter of time. Unfortunately, this logic is highly harmful, especially if looking for readily adaptable solutions to the CO₂ production problem.

Nuclear fission is a proven technology that can be deployed at scale relatively quickly to improve energy return on investment and address carbon emissions. Gen IV nuclear fission reactors will generate as much as 180 units of energy for every unit consumed, produce little to no waste, and be "walk away" safe. Utilities could commercially deploy these technologies in at least seven years with open access to capital markets.

Instead of committing to next-generation fission reactors (small modular reactors), investors have poured ~\$5 bn into private nuclear fusion companies (N.B., none of which were involved in the NIF "breakthrough"). In our view, this technology will never be viable as a source of electricity.

We commend the scientists working at NIF and elsewhere for their invaluable contributions to scientific advancement. However, the answer to our energy needs lies in a much more prosaic technology available now and operating safely for seven decades.

Vaclav Smil describes nuclear fission as the most successful failure in history. It is successful because it has achieved all of its goals; it is a failure because we inexplicably refuse to adopt it.

Copper Demand Soars: Is a Price Surge Coming?

"Codelco Production Slump Shows Copper's 'Tremendous Challenge'"

Bloomberg 1/24/2023

Copper demand remains strong. According to the World Bureau of Metal Statistics (WBMS), demand for the first ten months of 2022 ran 3.7% higher than the first ten months of 2021. Chinese demand continues to surprise to the upside, even with ongoing property woes and COVID-related lockdowns. For the first ten months of 2022, Chinese demand ran 5.5% higher than in 2021. Indian demand also continues to surge. For the first ten months of 2021, it grew over 30% year-over-year. In previous letters, we have outlined our belief that surging Indian copper demand would be one of the enormous surprises this decade. Led by increases in Germany and Italy, European demand is also surprising, running 3% higher than last year.

Total mine supply has not kept pace with demand, having increased by 1.7% year-over-year, according to WBMS data. The biggest surprise in mine supply has come from the unexpected drop in Chilean production, which fell unexpectedly by almost 300 tonnes this year, equating to 6%. Half of this shortfall has come from disappointing production from Codelco, the Chilean national copper company.

In our 2021 Q1 essay “The Problems with Copper Supply,” we stressed how falling ore grades and skyrocketing capital costs would eventually produce disappointments on a global basis. We find the Bloomberg news article cited at the beginning of this essay interesting. The authors wrote: “While Chile has the largest copper reserves, ore quality has been steadily falling. That means mines need to move more rock to produce the same amount, pushing costs.” Project development is also getting pricier, with the cost of Codelco’s new Chuquibambilla underground mine 53% above original estimates and investments in El Teniente 75% over budget.

In our essay, we traced the 32-year operating history of Escondida, the world’s largest copper mine, using it as a prime example of the problems associated with depletion and the exponential rises in capital expenditures needed to mine lower and lower-grade ore. Our study ended with 2020 data, and it is instructive to update it for 2021 and 2022.

After completing Escondida’s massive 2017 \$7 bn expansion, which increased sulfide milling capacity by almost 70%, copper production rebounded to 1.213 mm tonnes of copper from 770,000 tonnes produced in 2017. Rapidly falling head grades started eroding the mine’s ability to maintain copper production soon after.

By 2022, copper production had fallen by over 200,000 tonnes since 2018. Escondida processed ore with a head grade of almost 1.0% in 2018, but by 2022 it had fallen to 0.78% -- a steep drop of over 20%. The head grade explains practically 100% of lost copper production over the last four years. And our analysis predicts the head grade will drop further.

In 2017, there were 5.35 bn tonnes of minable copper ore at Escondida, with an average grade of 0.65%. Today, there are 5.09 bn tonnes with an average grade of 0.56%. Escondida’s minable ore grade fell by 14% in just four years. In 2022, Escondida mined ore with a head grade of 0.78%, significantly above the reserve grade of 0.56%. Escondida mine managers continue to high grade, first mining their best remaining areas, leaving the poorer sections behind. This all but guarantees production disappointments from now on. Escondida’s operational and production shortfalls represent problems in other copper mines.

Head grades are just one issue bedeviling the industry today. Rising nationalism in a variety

of countries is putting additional uncertainty over supply. In the last two years, populist governments in Chile, Peru, Bolivia, and Panama have all threatened and proposed significant increases in mining royalties and taxes.

The most recent and high-profile dispute emerged in Panama, home to the massive Cobre Panama mine (300,000 tonnes of annual production). The Panamanian government declared the 2018 mining law under which Cobre Panama operates to be unconstitutional. The government wants to hike the royalty rate eightfold from 2% to 16% and wants First Quantum (the owner-operator) to guarantee a minimum payment of \$375 mm per year, regardless of production or profitability. First, Quantum has threatened to cease operations, and negotiations are ongoing. At this time, both sides remain far apart.

Civil unrest in Peru has now forced the closure of two large copper mines -- Glencore's Antapaccay and MMG's Las Bombas. At 470,000 tonnes of combined copper production, these two mines represent about 2% of total world production. No one knows how long the unrest and blockades will continue. Peru has become a substantial copper producer over the last ten years, representing 9% of the world supply. What happens in Peru has an enormous impact on global production.

Copper demand is now running significantly above copper mine supply, further drawing down exchange inventories. Inventories are now at levels last seen in 2005, just before copper surged nearly three-fold.

China is reopening, which will likely result in a surge in copper consumption. The copper market is in a structural deficit, and inventories are dangerously low. We believe copper could see a massive surge in 2023, -similar to the period between 2005 and 2006.

Will 2023 Bring a Grain Market Black Swan?

“Egg prices soar due to deadly bird flu outbreak.”

Times Union 1/18/2023

When commodity markets fall into structural deficit, prices remain muted until a black swan event occurs, last year's 20-fold surge in global natural gas prices being an excellent example. The recent rise in egg prices provides another. Will global grain markets become susceptible to a black swan event that causes grain prices to skyrocket?

Although grain and fertilizer prices have corrected over the last nine months, grain markets

remain tight. As our readers know, we firmly believe we have entered a global cooling cycle that will bring on much more challenging and adverse crop-growing conditions this decade.

For those who could attend our investor day on November 3rd, we presented how the 40-year global warming cycle has dramatically boosted global grain yields by significantly increasing the growing season. Fewer late spring and early fall frosts, combined with increased precipitation here in the grain-growing belts of North America, have resulted in record harvests year after year.

We stressed that global warming had been the best thing for a world ever more hungry for animal protein and grain. If we are right that a new cooling phase has begun, we should see significant impacts on grain yields brought about by adverse weather conditions with much greater regularity.

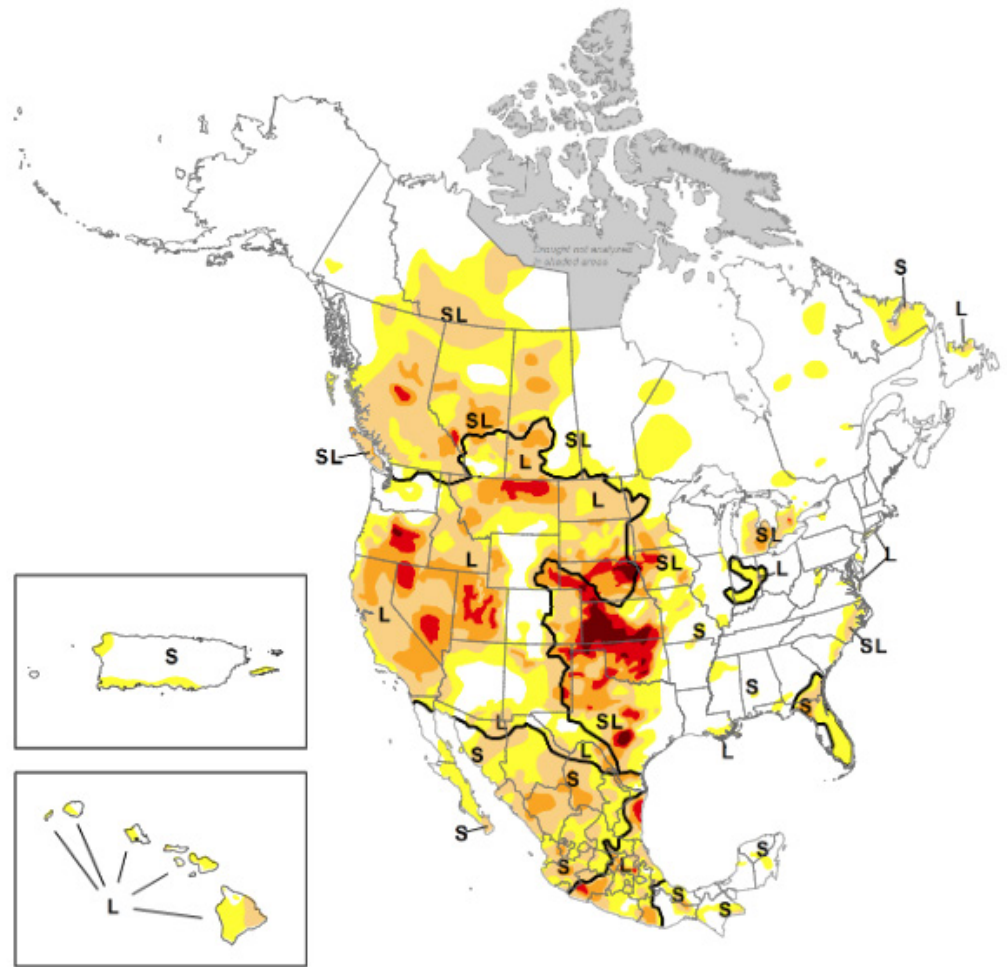
In what may be a forerunner of what to expect, adverse weather conditions experienced during the 2022-2023 growing season continue to impact grain balances. In their January World Agricultural Supply and Demand Estimates report (WASDE), the USDA unexpectedly reduced their 2022 estimates for corn acres harvested and soybean yields. Arid weather in parts of the western corn belt damaged the corn crop, so farmers decided against harvesting those acres. In their previous estimate, the USDA reported 80.8 mm acres would be harvested. In their January report, they cut this number to 79.2 mm acres. Because of drought conditions, the USDA spent almost all of the 2022 corn growing season reducing estimates for both acres planted, acres harvested, and yield. In their original May estimates, the USDA reported that 89.5 mm corn acres would be planted, 81.7 mm acres of which would be harvested, with an expected yield of 177 bushels per acre. By January, acres planted had fallen to 88.6 mm acres, acres harvested to 79.2, and realized yields to 173.3. The USDA initially estimated the US corn harvest would reach 14.46 bn bushels. They now estimate it will only be 13.73 bn bushels, a drop of 5%. The US 2022-2023 corn ending stock figures have fallen to 1.24 bn bushels. Corn ending stocks are expected to hit levels seen only twice in the last 45 years. When adjusted for daily consumption, they are at record lows.

In soybeans, extremely hot weather damaged crops more, and the USDA reduced soybean yield by an additional 0.7 bushel per acre in their January report. Like corn, the USDA underestimated dry and hot conditions in the soybean growing belt and overestimated the crop size. In their original projection last May, the USDA estimated 91 mm planted soy acres with 90.1 mm harvested acres and a yield of 51.5 bushels per acre, a new record. In their latest January WASDE report, the USDA estimates that only 87.5 soybean acres were planted, 86.3 were harvested, and yields would reach 49.5 bushels per acre. The original size of the soybean crop was estimated at a record 4.64 bn bushels. The USDA now estimates the soybean crop will only reach 4.28 bn bushels, almost 8% lower. Soybean ending stocks are now estimated to reach 210 mm bushels -- again approaching dangerously low levels.

Weather-related supply disappointments in the United States, Europe, and India, combined with war-related supply disruption in Ukraine that will continue into 2023, mean that global grain markets will remain tight. A black swan event would have a devastating effect.

What might this event be? We believe that it will be related to the persistence of today's La Niña weather pattern. Much of the dryness impacting large swaths of both the central and western US and western Canada can be attributed to the La Niña in force in the Pacific Ocean since the summer of 2020. Late last year, weather models strongly suggested that the La Niña would shift into an El Niño once 2023 was over. If this happened, the drought that has gripped a large swath of the US and Canada's central and western sections would most likely ease, with highly positive implications for crop-growing conditions in both countries. However, it now looks like the weather models have flipped and strongly indicate that the present La Niña should extend through 2023. Dry and potentially severe drought conditions may continue to grip the midsection of the US and Canada this coming year.

FIGURE 11 North American Drought as of 1/31/2023



Source: North American Drought Monitor.

North American dry weather this year and next could be worsened by the upcoming Gleissberg solar cycle, a phenomenon named after the

German scientist Wolfgang Gleissberg. Gleissberg noticed how variations in the sun's magnetic fields repeated every 90 years or every nine solar cycles. The last Gleissberg cycle occurred in the early 1930s, coinciding with the infamous Dust Bowl; the next is expected in 2023-2024. For those interested in sunspot activity and the potential impact on weather, please refer to our Q1 2019 essay, "What Sunspots Mean for Global Growing Conditions," which gives a broad overview.

Sunspot scientists believe the Gleissberg cycle contributed significantly to the extreme drought conditions in the 1930s. While vigorous debate surrounds the Gleissberg cycle, significant evidence shows that record droughts have coincided with the cycle throughout history.

Given the projected persistence of La Niña into 2023 and the Gleissberg sunspot cycle, we run the risk of severe drought conditions here in North America over the next two years and another considerable run-up in grain prices at some point in 2023, as adverse growing conditions have the potential to impact supply significantly.

Unlocking the Potential of Precious Metals

Precious metals markets flashed a vital sell signal back in August 2020: silver staged a furious catch-up rally after lagging the gold market for nearly two years by almost 50%. Starting in May 2020, silver rallied, more than making up for its underperformance over the previous 18 months. Catch-up rallies of similar magnitude happened in 1973-1974, 1979-1980, and 2010-2011. After each occurrence, both gold and silver prices experienced significant and prolonged price setbacks. Heeding

silver's sell signal advice was the right thing to do every time. After the 1973-1974 sell signal, gold and silver prices fell 45%, and gold stocks, as measured by Barron's gold stock index, fell 70% in the following two years. After the 1979-1980 catch-up silver rally, gold, and silver prices spent the next 20 years falling in a grueling bear market. Gold prices ultimately fell 70%, silver prices fell 90%, and gold equities, as measured by Barron's gold stock index, fell 80%. After the 2011 sell signal, the precious metals complex spent the next four years in a bear market. Gold fell 45%, silver fell 70%, and gold equities, as measured by the GDX ETF, fell 80%.

In contrast to these periods, the 2020 sell signal has only produced a mild pullback in precious metals and their related equities.

Gold stands only 5% below its all-time high. Silver's decline, although more prominent, has also been shallow compared to those other episodes. Peak to trough silver's decline has been only 40%, and today it sits only 15% under its 2020 highs. Gold stocks have also held up significantly better. Since peaking in November 2020, gold equities bottomed in September 2022 down 40%, and today they sit only 20% below their 2020 highs.

As outlined in previous letters, we believed this pullback in precious metals, triggered by silver's sell signal, would be similar to the 1974 correction in a larger bull market instead of an outright lengthy bear market like what happened post-1980 and 2011. Gold's low valuation and its limited investor interest made it unlikely a new precious metals bear market was about to unfold.

Starting in 1973, the Fed aggressively raised interest rates in the face of rapidly rising inflation brought on by the 1973 Arab oil embargo. The Fed doubled the Funds rate to 14% in the summer of 1974, and the back of the gold bull market, which started in 1971, was eventually broken; however, the pullback in precious metals prices lasted for just two years. By the summer of 1976, gold had bottomed at \$105 (silver had bottomed earlier in February of 1976 at \$3.85), and both were about to start substantial new bull market moves.

In a repeat of 1973-1974, the Fed aggressively raised rates from zero to 4.25%, and just as in 1974, the steep rise in interest rates forced a period of correction on precious metals markets.

We firmly believe that the gold bull market has only started and that a substantial new bull market leg stands directly before us, but the question remains timing. When should investors significantly increase their exposure to the precious metals complex? We're watching these underlying data points.

Positioning of COMEX traders: Bullish/Neutral

When commercial COMEX precious metals traders go long, that's a bullish sign. The commercials represent "smart" money and usually maintain short positions to hedge their long physical inventories; however, in the few instances when they do go long, that's usually a very bullish sign. Conversely, when speculators (the trend followers) go short, that often signals a buying opportunity. Having both commercials going long and speculators short usually indicates that a significant buying opportunity has arrived. Following last summer's silver price pullback, COMEX silver traders flashed a strong buy signal as both commercials went net long and speculators went net short in the first week of September. However, as you can see from the chart below, traders in the COMEX gold markets

did not confirm the buy signal flashed from the silver trading markets. Back in the summer and fall of 2018, as gold and silver prices pulled back, both silver and gold COMEX traders

flashed buy signals that signaled

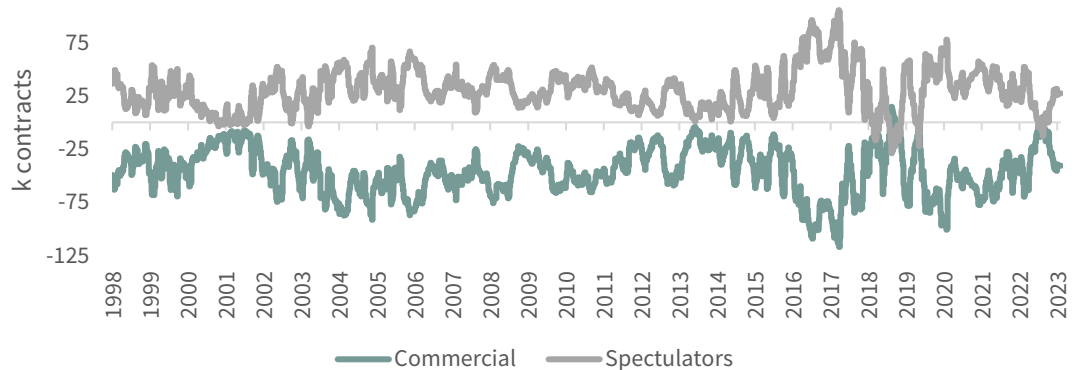
investors had reached an excellent entry point. Gold and silver and their related equities advanced strongly over the next two years.

We were hoping last summer's precious metals price weakness

would produce an oversold condition deep enough to register a buy signal from gold and silver COMEX traders, as it did in 2018.

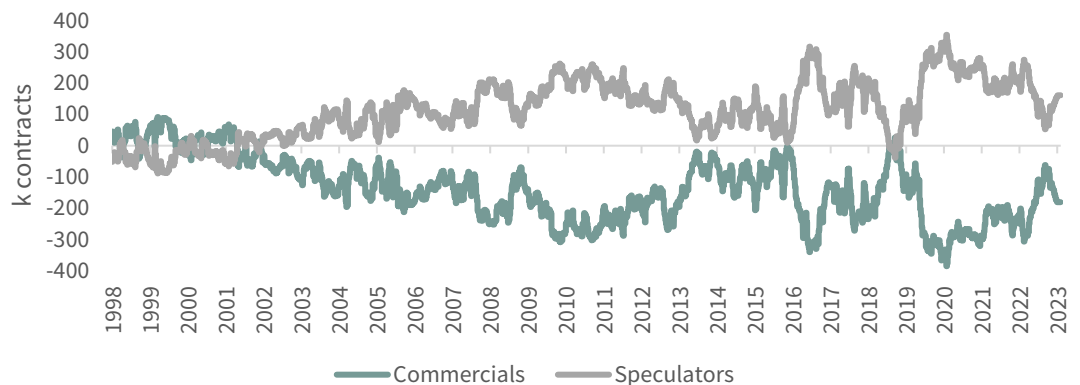
Although we did not get a buy signal from COMEX traders, please note that huge upwards moves in gold prices can occur without it, as has happened multiple times between 2003 and 2009. We would have liked to see a buy signal flashed from both gold and silver traders, as we saw in 2018, but maybe a silver trader COMEX buy signal will be the only one we'll get in the precious metals price pullback.

FIGURE 12 Silver Commercial / Spec Positions on Comex



Source: Bloomberg.

FIGURE 13 Gold Commercial / Spec Positions on Comex



Source: Bloomberg.

Central Bank Buying: Extremely bullish

Central banks' gold buying continues to set modern-day records. For all of 2022 central bank purchased one thousand one hundred thirty-six tonnes of gold, the second-highest amount ever. According to the World Gold Council (WGC), you must return to 1967 to find central bank purchases of that magnitude. The robust central bank buying in Q4 is of particular interest. According to the WGC, central banks purchased 417 tonnes in Q4 -almost surpassing the total amount of central bank purchases that occurred in all of 2021. The most important buy came from the People's Bank of China, which announced it had purchased 62 tonnes in November and December. China's central bank's last purchase occurred back in September 2019; now, China's official gold reserves are at over 2000 tonnes, 3.4% of total reserves. Given China's long-term desire to undermine the reserve currency status of the US dollar (look no further than China's proposal to the Saudis that they trade oil in renminbi),— it will have to own a lot more gold to reinforce the long-term value, integrity, and ultimate convertibility of the renminbi on global currency exchanges. Aggressive central bank buying, led by China, gives us further confidence that today's corrective price pattern in the precious metals markets is nearing its end.

Western Investor Buying: Neutral—but about to turn positive?

Nearly 100% of gold's move from \$250 in 1999 to \$1,900 in 2011 can be attributed to buyers in China and India.

However, individual Eastern investors have lost their appetite for gold in the last five years. As value buyers, their hunger receded with gold at \$1,900, not \$250. In 1999, before the bull market started, with gold priced as low as \$260 per ounce, China and India consumed 205 tonnes and 840 tonnes of gold, respectively. By 2010, China's gold consumption had soared to over 600 tonnes, and India's hit 965 tonnes.

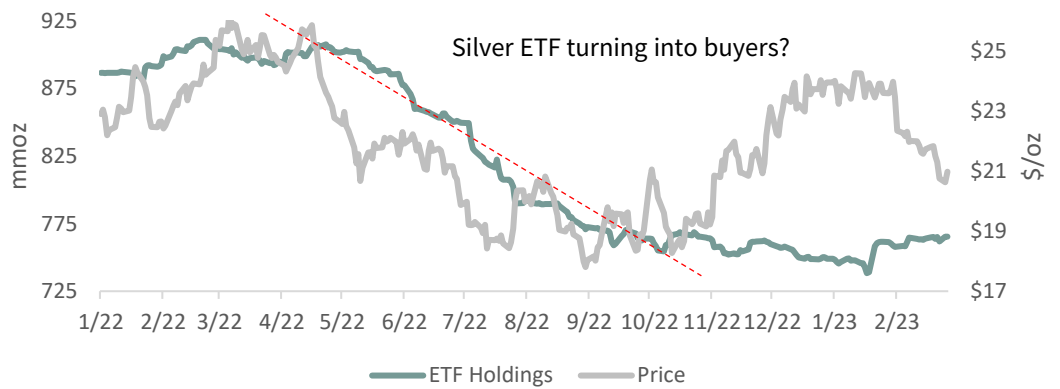
Since gold peaked in 2011, India and China have shown negative trends in consumption. India's gold consumption peaked in 2010 at 960 tonnes, and according to WGC figures, India in 2022 has consumed only 780 tonnes. China shows a similar drop. China's gold consumption peaked in 2012 at 820 tonnes, and since then, China has shown no growth. According to WGC figures, China consumed 780 tonnes of gold last year.

Suppose Eastern buyers treat gold as an asset class that should be aggressively accumulated at low prices and sold at a higher price. In that case, it stands to reason that the enormous surge in buying interest between 1999 and 2010-2012 will not repeat this decade. Given the waning interest of Eastern buyers, the importance of Western buying behavior becomes all the more critical. As opposed to Eastern buyers, who use low prices and value as the reason to buy, Western investors use momentum and the potential for speculative profit as their main reason to buy. In the East, higher gold prices reduce gold demand; in the West, higher

prices do just the opposite. As prices rise, so does demand, as traders pile in expecting to reap speculative profits.

Understanding that western buyers will drive the gold market's next leg, it becomes imperative to track what Western investors are doing closely. To monitor Western gold and silver buying interest, we track 16 gold and eight silver ETFs' daily holdings of the physical metal. As you can see, since 2010, the direction of gold and silver prices has been heavily influenced by whether these ETFs are shedding or accumulating metal.

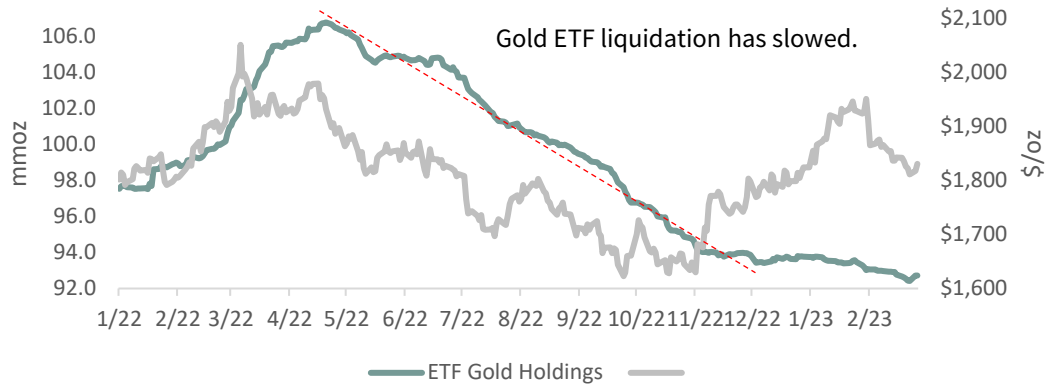
FIGURE 14 Silver ETF Holdings & Price



Source: Bloomberg.

Last January, we experienced a significant “head fake” in gold markets when these physical gold ETFs began a three-month accumulation phase. However, in the face of a very aggressive Federal Reserve rate increase, Western buyers turned into aggressive sellers, primarily responsible for the 20% gold price declines between March and November. However, as shown in the chart below, our 16 physical gold ETFs have significantly slowed their gold sales since the beginning of December.

FIGURE 15 Gold ETF Holdings & Price



Source: Bloomberg.

After shedding 450 tonnes of gold since last April, gold shedding from these ETFs has slowed to a trickle. Gold sales have slowed to only 8 tonnes in the previous two months. We believe slowing ETF sales and surging central bank purchases have allowed gold to rally almost 20% since the beginning of November. Western gold sellers may turn into buyers, and we closely monitor them.

A similar situation has developed in the physical silver ETFs we track. After aggressively shedding approximately 3,700 tonnes of silver since the end of April last year, it looks like the silver shedding momentum has been broken—as clearly shown in the chart below. Have western silver investors turned from sellers into buyers? Given the bullish signal flashed by COMEX traders back in August, we're confident they have. Since flashing that buy signal, silver prices have rallied 40%.

The behavior of physical gold and silver ETFs have switched from strongly negative to neutral, and we are eager to see if the recent investment behavior continues.

When does the next leg of the gold market start? Evidence strongly suggests that it is getting closer and closer, and investors with no performance constraints should maintain total precious metals exposure. Even for investors with performance constraints, we recommend they significantly raise their exposure. It has paid to have even minimal precious metals exposure over the last two and half years, especially relative to other natural resource sectors of the market.

Open Letter to State Treasurers

Several state treasurers have withdrawn billions of dollars worth of investment assets from managers over ESG concerns in recent months. The treasurers worried that firms like Black-Rock were too focused on climate change to the detriment of their fiduciary responsibility.

We agree that many elements of ESG investing have been disastrous and applaud the state treasurers for their resolute actions.

For nearly a decade, countless firms have liquidated their energy investments entirely after bowing to ESG pressures, setting de-facto energy policy by redirecting capital flows away from E&P companies, often with no explicit mandate. In July 2008, energy companies made up 16% of the market capitalization of the S&P500. As recently as 2014, they were 10% of the market. Since then, widespread ESG initiatives and a bear market in oil prices have led many investors to sell their energy holdings entirely. By November 2020, energy made up 1.8% of the S&P500, the lowest level in history. Two years later, energy companies generated over 20% of the EBITDA of the S&P500 but still represented less than 5% of its market capitalization, less than half the long-term average.

Using investors' cues, energy companies have stopped investing in their assets. As energy demand fell, capital expenditures plummeted during COVID and have yet to rebound. Most analysts expect energy spending in 2023 will be 30-40% lower than in 2019, despite much higher energy prices. Many companies prefer to return free cash flow to shareholders through dividends and buybacks instead of reinvesting in new oil and gas drilling. Our research suggests that hostile ESG rhetoric and depressed corporate valuations are primarily responsible for these capital allocation decisions. Given how cheap E&P companies are, management can often generate a better return by buying back their stock than through the drill bit.

None of this bodes well for our energy supply. Over the past 15 years, nearly all global oil and gas production growth has come from the US shales. If we restrict capital to these vital assets, we risk turning off the sole source of traditional energy growth. Furthermore, the US has gone from a large energy importer to a net-energy exporter. If we continue to starve the industry of capital, it is only a matter of time before we slip back to being large-scale net energy importers.

Moving away from firms that push traditional energy divestment is an essential first step. However, this is too little too late. Investors have already removed so much capital from the energy industry that to fix this problem, institutional investors must actively target those companies directly funneling money back into the energy business. The effects of a decade of energy divestment are hard to overcome. Today, many generalist investors and analysts have never learned anything other than to sell energy stocks. In 2022, energy equity ETFs saw net redemptions, despite being the best-performing sector in the S&P500.

To secure an abundant energy supply, we must get capital back to the E&P industry and encourage them to deploy it. At Goehring & Rozencwajg, we have invested in the energy sector throughout the bear market and continue to do so today.

We are not blind to the issues surrounding carbon emissions. However, many proposed solutions (notably wind and solar) are not viable. By moving capital away from traditional energy towards these new solutions, we risk not only impairing trillions of dollars but also not solving the underlying carbon issue. Economic incentives and the free market are the best way to generate an efficient outcome.

This communication may include opinions and forward-looking statements. All statements other than statements of historical fact are opinions and/or forward-looking statements (including words such as "believe," "estimate," "anticipate," "may," "will," "should," and "expect"). Although we believe that the beliefs and expectations reflected in such forward-

looking statements are reasonable, we can give no assurance that such beliefs and expectations will prove to be correct. Various factors could cause actual results or performance to differ materially from those discussed in such forward-looking statements. All expressions of opinion are subject to change. You are cautioned not to place undue reliance on these forward-looking statements. Any dated information is published as of its date only. Dated and forward-looking statements speak only as of the date on which they are made. We undertake no obligation to update publicly or revise any dated or forward-looking statements. Any references to outside data, opinions or content are listed for informational purposes only and have not been verified for accuracy by the Adviser. Third-party views, opinions or forecasts do not necessarily reflect those of the Adviser or its employees. Unless stated otherwise, any mention of specific securities or investments is for illustrative purposes only. Adviser's clients may or may not hold the securities discussed in their portfolios. Adviser makes no representations that any of the securities discussed have been or will be profitable. Investment process, strategies, philosophies, portfolio composition and allocations, security selection criteria and other parameters are current as of the date indicated and are subject to change without prior notice. Investments in securities are not insured, protected or guaranteed and may result in loss of income and/or principal. Historical performance is not indicative of any specific investment or future results. Diversification does not eliminate the risk of market loss. A long-term investment approach cannot guarantee a profit. Indices are not available for direct investment. Their performance does not reflect the expenses associated with the management of an actual portfolio. Clients cannot invest directly into and index.