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THE IEA USHERS IN THE COMING OIL CRISIS

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"We want [Exxon] to change from within. They need to wake up and recognize the future is different. Get out of the oil and gas focus." Chris Ailman, Chief Investment Officer, California State Teachers' Retirement System press release

"The contraction of oil and natural gas production will have far-reaching implications for all the countries and companies that produce these fuels. No new oil and natural gas fields are needed in the net zero pathway, and supplies become increasingly concentrated in a small number of low-cost producers. OPEC's share of a much-reduced global oil supply grows from around 37% in recent years to 52% in 2050, a level higher than at any point in the history of oil markets." Fatih Birol, Executive Director, International Energy Agency, May 17, 2021

The IEA Ushers in the Coming Oil Crisis

The foundation for the upcoming oil crisis is now firmly set in place. The world is re-opening and global oil demand is recovering strongly. By the beginning of 2022, global oil demand should be making new highs. Non-OPEC oil supply has fallen by over 2 mm barrels per day from its 2019 peak and non-OPEC oil supply growth will turn negative as we progress through this decade. A structural gap will soon emerge between supply and demand. As early as Q4 of 2022, demand will approach world oil-pumping capability — a first in 160 years of oil history. The ramifications will be huge and the investment implications monumental.

The International Energy Agency's (IEA) bombshell release of its “Net Zero By 2050” report on May 17th, 2021 added more fuel to the fire. In that report, the IEA aggressively recommended that the global oil and gas industry stop investing in their traditional upstream businesses. Instead, the IEA recommended capital should be redirected to other uses — primarily renewable energy projects.

The IEA was established by the industrialized nations to carefully monitor and ensure the security of oil supplies after the 1973–1974 oil crisis. Preventing oil shocks caused by unanticipated and severe oil supply disruptions, was its primary goal. In the May 17th paper, Dr. Fatih Birol reiterated the IEA's primary purpose: “Since the IEA's founding in 1974, one of its core missions has been to promote secure and affordable energy supply to foster economic growth.” How ironic it is that an agency, originally trusted with the encouragement of oil supply security, is now aggressively adopting policies that will severely hinder the security of those supplies. The IEA's policies will produce outcomes exactly at odds with their original charter.

The irony is stunning and the unintended consequences will be far reaching.

The biggest unintended consequence is clearly and ironically alluded to in the IEA's own May 17th press release. The IEA states: “The contraction of oil and gas production will have far-reaching implications for all the countries and companies that produced these fuels. [...] Supplies become increasingly concentrated in a small number of low-cost producers. OPEC's share of a much-reduced global oil supply grows from around 37% in recent years to 52% in 2050, a level higher than at any point in the history of oil market.”

Back in the early 2000s, we became very bullish on oil prices. I was profiled in Barron's February 9th 2004 edition in an article titled: “Pumped Up: A Natural Resource Maven Sees a Long-Term Bull Market for Oil.” In the profile, I stated: “We're just beginning to see a noticeable slowdown in non-OPEC supply of oil, which is bound to press more power into the hands of the oil cartel.” At the time, oil stood at \$35 per barrel. Four years later, oil had eclipsed all expectations and surged to \$145. What explained the four-fold surge in less than 5 years? In retrospect, the answer is simple: after a dramatic slowdown in non-OPEC oil supply growth, OPEC gained market share and pricing power.

In 2004, non-OPEC oil supply was set to experience a sharp slowdown in growth. Supply from some of the world's largest producing fields and regions (Prudhoe Bay in Alaska, Cantarell in Mexico and the North Sea) were all exhibiting accelerating production declines while the great US oil shale boom was still half a decade away. As a result, non-OPEC oil supply experienced no growth between 2003 and 2008. Over that period, we wrote repeatedly to our investors: “Remember, the biggest competitor to OPEC oil is non-OPEC oil and when the growth of non-OPEC slows, OPEC gets pricing power.”

Between 2002 and 2008, OPEC's market share of global production went from 38% to 43%. This small increase in market share resulted in huge OPEC pricing power allowing crude to advance four-fold in five years. The same chain of events that started in 2004 is about to be repeated with a vengeance.

The IEA's policies will accelerate the huge slowdown we are about to experience in non-OPEC oil supply growth. Just like what happened between 2003 and 2008, OPEC will gain market share and pricing power — a situation the IEA acknowledges and even seems to be encouraging.

Over the last decade, surging US shale oil and NGL production added almost 10 mm barrels per day to non-OPEC oil supply, leaving OPEC in a defensive position. OPEC's spare capacity was unleashed twice over the last decade (2014 and 2020) to protect and regain market share that had been lost to the US shales. Now that non-OPEC oil supply is set to contract, OPEC sits in the enviable position of regaining market share and pricing power. Significant potential price spikes may occur as OPEC once again flexes its control over prices.

Energy analysts are convinced global oil demand, for ESG and EV reasons, will collapse faster than non-OPEC supply, putting pressure on OPEC to wage incessant market share wars. Instead, our global oil demand analysis (extensively discussed in these letters over the years) continues to suggest further growth in oil demand this decade, a viewpoint far from consensus. In retrospect, the COVID-19 related retrenchment in oil demand now looks to have been of far smaller magnitude than originally thought and the rebound in global oil demand is proceeding at a pace much faster than originally anticipated. 2019 pre-COVID oil demand levels now look like they will be exceeded within the next six months. Not only has China made significant new highs in oil consumption, but it now looks like the United States' oil demand has made new highs as well. The resiliency of global oil demand, even in the face of a global economic lockdown, supports our demand analysis and gives us confidence that oil demand will continue to show growth this decade.

Back in July 2020, we wrote an essay titled "The Coming Oil Crisis." Its timing was certainly contrarian: headlines painted a bleak picture for global oil markets. In response to the COVID-19 pandemic and its related lockdowns, oil demand had collapsed and inventories surged. The history-making collapse that took oil prices negative only three months earlier still reverberated throughout the market and many wondered if prices would ever recover.

Although fundamentals appeared grim, several very important bullish data points began emerging last summer. First, weaker-than-expected inventory builds strongly suggested demand had remained far more resilient than commonly believed. Second, production data clearly indicated severe problems had already crept into US shales — the only source of growth in the non-OPEC world over the last 10 years.

We concluded that once the COVID pandemic ended and the global economy started to recover, investors would realize that a structural gap had emerged between supply and demand.

Before the COVID-19 pandemic, our models suggested that only 2.5–3.0 mm barrels of excess global supply existed versus demand and that over 60% of this excess pumping capability was controlled by Saudi Arabia and Iran. Given the huge cutbacks in global upstream capital spending and given production declines in the US shales, non-OPEC+ oil supply is now running over 2.5 mm barrels per day below 2019 levels. If rebounding global oil demand exceeds the 2019 high of 101 mm barrels per day, then for the first time in the history of oil markets, demand could very well approach global pumping capability.

The importance of that statement cannot be overstated. Even during the two oil crises of the 1970s, global oil demand never came close to surpassing global oil pumping capability. If our modelling of the shales and non-OPEC+ oil supply is correct, then demand could surpass supply as soon as 4Q 22. Tight oil balances leave the oil market susceptible to even the smallest supply disruptions, including that OPEC might choose to aggressively use its newfound pricing power.

Over the last decade, the US shales have provided a buffer for world oil markets. That buffer is now gone. As we progress through the first half of this decade, oil markets will become far more susceptible to frequent and pronounced price spikes.

And we say this even before considering events that impacted both Exxon and Royal Dutch Shell two months ago.

In the last week in May 2021, Exxon was dealt a “stunning defeat,” according to *The New York Times*. Activist investor Engine No. 1 elected 3 new directors (out of a total of twelve) to Exxon’s board despite owning a mere 0.02% of the shares outstanding. Engine No. 1’s mandate was to reduce Exxon’s carbon footprint by curtailing capital investments into its upstream oil and gas businesses. At the same time, a Dutch court ruled that Royal Dutch Shell must cut its CO2 output by 45% by 2030 to align company policy with the Paris Climate Accord. In a statement issued directly after the verdict, a Shell spokesperson acknowledged that “urgent action is needed on climate change and that the company is accelerating efforts to reduce emissions.” The company said: “We are investing billions of dollars in low-carbon energy, including electric vehicle charging, hydrogen, renewable and biofuels.” What is not said is where all these billions will come from. However, the implication is clear: Royal Dutch’s upstream oil and gas business will be capital starved.

While Engine No. 1’s board coup and the Dutch court ruling may seem unrelated, we believe both are tied to the IEA’s May 17th report. Proxy voting services have been eager to adopt green policies. However, their voting guidelines have been limited to clients who have specifically asked for ESG mandates. With the IEA’s newly adopted policies, these voting services can now point to the findings of the most important energy oversight group (the IEA) when recommending more aggressive green initiatives to their clients. At the same time, passive investment vehicles (primarily ETFs) have become major shareholders in most large companies. These ETFs almost always vote in-line with the recommendations of these proxy services. As a result of these two developments, activist shareholders with de minimis equity ownership interest are now able to exert disproportional influence on a company’s board and its corporate policies. What happened to Exxon could very well happen to other large oil companies. The implications for oil supply are massive. Similarly, we believe the Dutch courts were able to use the IEA report as “cover” in recommending what would in past years have been viewed as an overly interventionist ruling.

The following essay studies four oil supermajors (Exxon, Chevron, Royal Dutch Shell and Total) in terms of reserves and production trends. In all four cases, both reserves and production have stagnated over the past decade. In the case of Chevron and Royal Dutch Shell, oil reserves and production have already begun to severely decline. These trends have emerged despite ample upstream capital spending over the past two decades. What will happen once all the supermajors are forced to dramatically cutback upstream spending the way Exxon and Royal Dutch Shell are now?

"WHAT WILL HAPPEN ONCE ALL THE SUPERMAJORS ARE FORCED TO DRAMATICALLY CUTBACK UPSTREAM SPENDING THE WAY EXXON AND ROYAL DUTCH SHELL ARE NOW?"

"THE OIL ENERGY CRISIS IS HERE. INVESTORS MUST BE PREPARED."

In previous letters, we have carefully outlined our belief that non-OPEC+ oil supply outside of the US has already started to decline. Over the last 10 years, the only source of non-OPEC+ oil supply growth has been the shales. Except for the Permian basin, every shale in the US is now in persistent decline. The shales remain 1.4 m b/d below their highs and our modeling suggests they will never regain previous production peaks. Even before the massive upstream capital cutbacks now being forced on the supermajors by ESG pressures, production from this group was in decline. These declines will only accelerate.

The previous bull market started in 1999 and saw oil prices rise 13-fold from \$11 to \$145 per barrel. The most dramatic part of this move occurred between 2003 and 2008 as weakness in non-OPEC production allowed OPEC to regain market share and exercise pricing power. While oil bears will continue to claim that EVs make things different this time, we believe the most important driver of the oil market going forward will be the lack of non-OPEC+ supply.

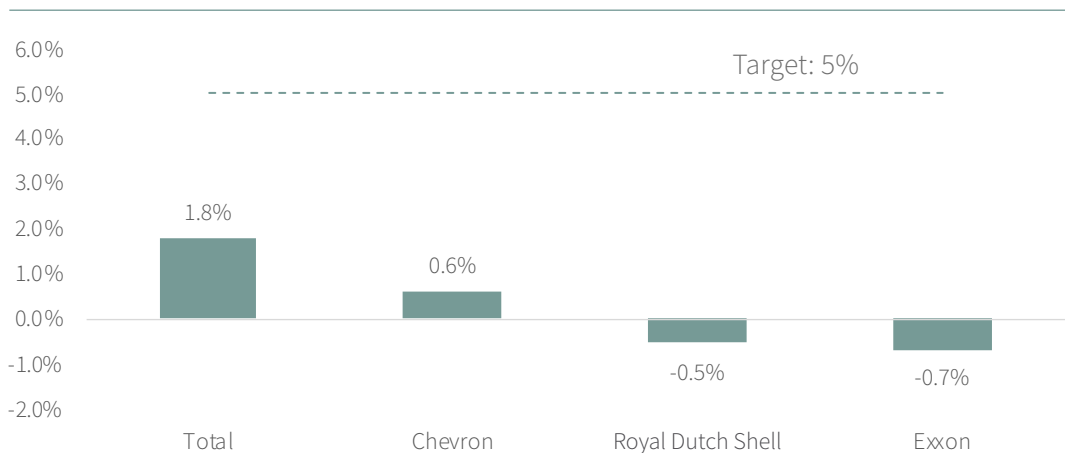
The oil energy crisis is here. Investors must be prepared.

The Incredible Shrinking Oil Majors

Oil production growth outside of OPEC+ and the US shales has been extremely difficult to achieve — even before the ESG pressures discussed in the introduction. This essay will highlight the problems faced by the oil supermajors: Exxon, Chevron, Royal Dutch Shell and Total. Over the last 20 years, these companies have found it challenging to maintain their reserve base and production level. Even though upstream capital spending has surged, production and reserves have persistently declined. As ESG pressures constrain upstream spending, both oil reserves and production at these four companies will likely enter severe declines. Because of the tremendous corporate dislocation created by the 2010 Macondo oil spill, we have left BP out of this study.

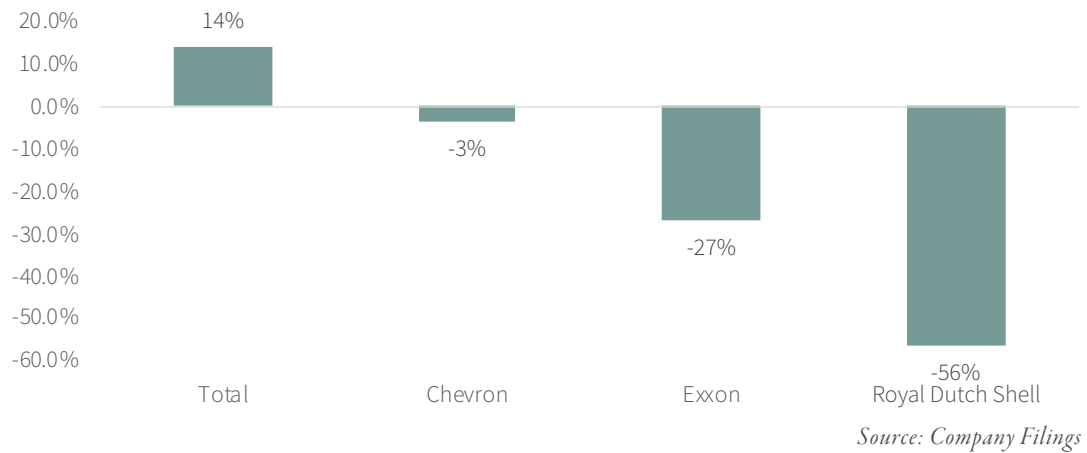
Since 2000, every oil supermajor has targeted 5% production growth. Not only were these growth projections far too ambitious, two of the four supermajors are now actually smaller than they were 20 years ago. Exxon's upstream production is down 12% while Royal Dutch Shell is down 9%. Only Total and Chevron have distinguished themselves by showing any annual production growth at all — 1.7% and 0.6% CAGR respectively since 2020. Proved oil and gas reserves paint the same picture. Exxon's reserves are 27% lower while Royal Dutch

FIGURE 1.1 BOE Production Growth CAGR 2000–2020



Source: Company Filings

FIGURE 1.2 Reserve Growth (BOE) 2000–2020



Shell's are 56% lower and Chevron's are 3% lower. Only Total has grown at all over the last 20 years: its proved oil and gas reserves are 14% greater than in 2000.

Things look significantly worse if you focus only on crude oil. While Exxon's crude oil production has declined by 8% over the last 20 years (in line with gas production), Royal Dutch Shell's crude production has collapsed by 20% while Chevron's has fallen by 7%. While Total is once again the only company to show any growth, it has been modest: oil production is

FIGURE 2.1 Oil Production Growth CAGR 2000–2020

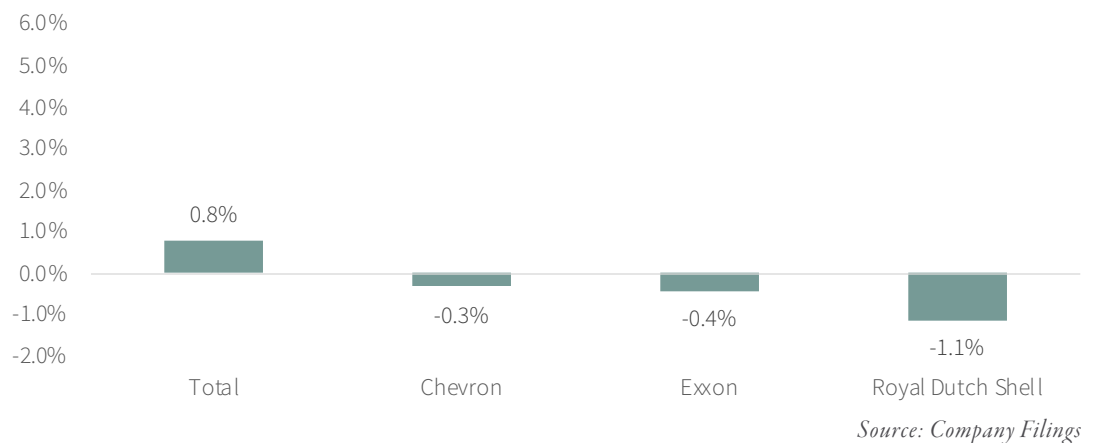
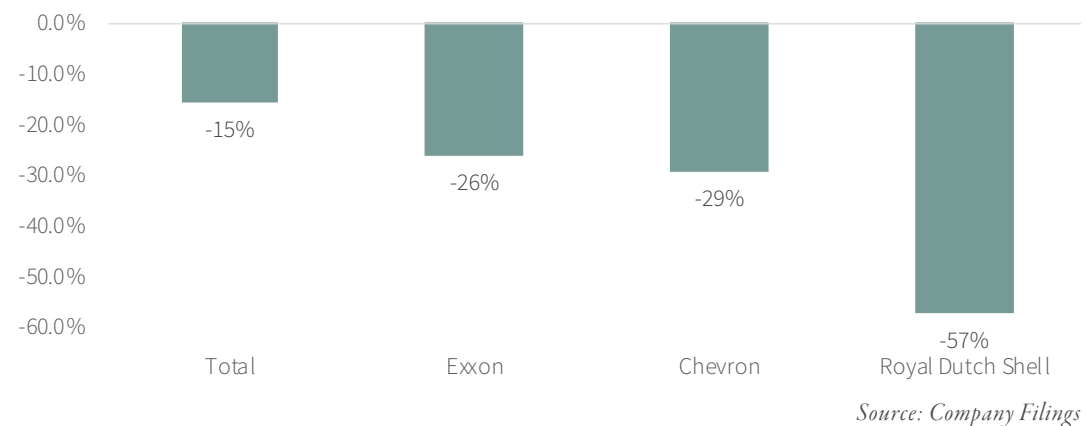


FIGURE 2.2 Oil Reserve Growth 2000–2020



"RESERVES HAVE FALLEN FASTER THAN PRODUCTION, CAUSING THE RESERVE-TO-PRODUCTION RATIO (R/P) TO DECLINE."

up 0.8% CAGR over the last 20 years. Proved oil reserves tell a similar story. Exxon's proved oil reserves are down 26% while Royal Dutch Shell's have collapsed by 57% and Chevron's have fallen 29%. Even Total's proved oil reserves have contracted by 16% since 2000.

Reserves have fallen faster than production, causing the reserve-to-production ratio (R/P) to decline. Exxon's R/P for total proved reserves fell from 10.1x in 2000 to 8.4x by 2020 while Royal Dutch Shell's ratio fell from 14.6x to 7.4x and Chevron's fell from 11.9x to 9.9x. Even Total was unable to halt the decline of its R/P ratio. Despite reserves growing, production grew more causing their total proved reserve R/P ratio to fall from 13.8x in 2000 to 11.1x by 2020.

Once again, focusing only on oil is even worse. While all four supermajors saw their total proved R/P ratios fall by 26% on average, their oil-only proved R/P ratios fell by 30%. Of the four companies, only Exxon's proved oil R/P ratio remained above 10 in 2020.

FIGURE 3.1 Reserve to Production Ratio

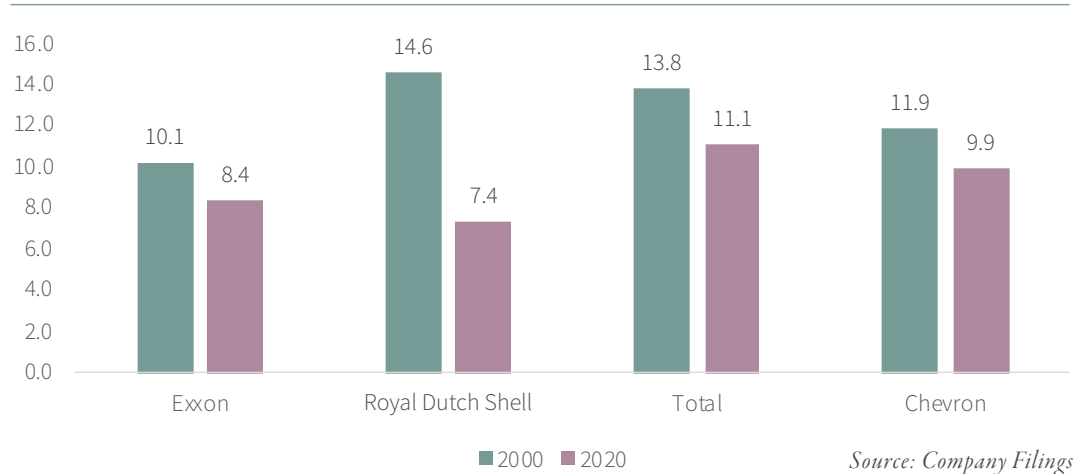
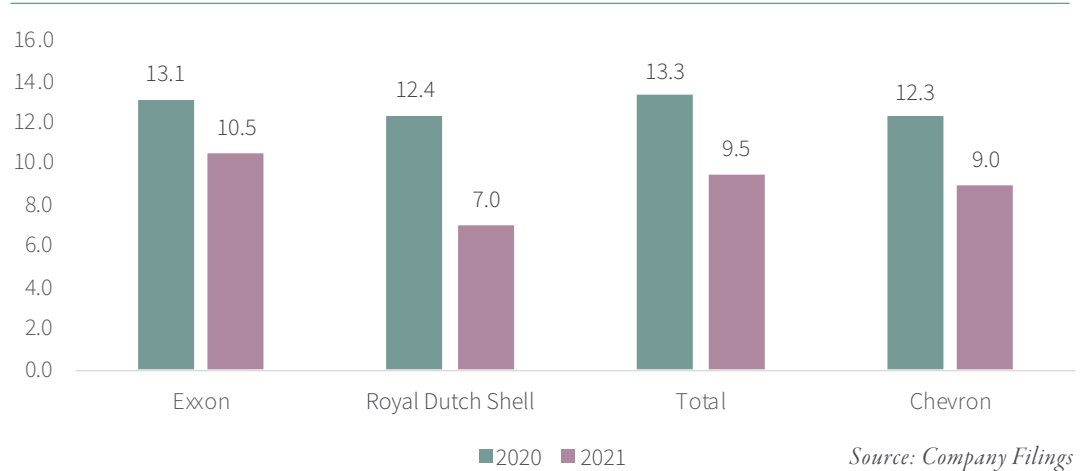


FIGURE 3.2 Oil Reserve to Production Ratio



While these upstream metrics alone point to a challenging future for the supermajors, when you factor in the massive capital spending that took place over the last decade, the true severity of the situation becomes clear.

"WHILE THESE UPSTREAM METRICS ALONE POINT TO A CHALLENGING FUTURE FOR THE SUPERMAJORS, WHEN YOU FACTOR IN THE MASSIVE CAPITAL SPENDING THAT TOOK PLACE OVER THE LAST DECADE, THE TRUE SEVERITY OF THE SITUATION BECOMES CLEAR."

"THESE NUMBERS HIGHLIGHT THE CHALLENGES FACING THE SUPERMAJORS. WITH THE ADDITION OF ESG PRESSURES, THE FUTURE FOR THESE COMPANIES HAS GONE FROM CHALLENGED TO INCREDIBLY BLEAK."

Between 2000 and 2010, the four supermajors spent \$615 bn on upstream capital expenditures. Over the same period, they produced 50.3 bn barrels of oil equivalent (boe) and found 41.1 bn boe of new reserves, resulting in a reserve replacement ratio of 86% (not very good) at an average finding and development cost of \$14.30 per boe.

Between 2010 and 2020, upstream capital expenditures surged to \$1.15 tr. Over the same time, the companies produced 50.6 bn boe and found 43.3 bn boe of new reserves — very much in line with the decade prior. Even though upstream capital spending nearly doubled, the companies were still unable to replace production with new reserves. In fact, reserve replacement was unchanged at 85% despite the increase in spending. As a result, the cost to find and develop a new barrel of reserve nearly doubled from \$14.30 per boe to \$26.40.

These numbers highlight the challenges facing the supermajors. With the addition of ESG pressures, the future for these companies has gone from challenged to incredibly bleak.

The impact of ESG will show up in two places. First, upstream capital spending will be difficult if not impossible to grow going forward. The supermajors are already under intense pressure to cutback traditional upstream spending and redirect the cash flows into renewable energy projects. Because the cost to find and develop new reserves has more than doubled over the last 20 years, any cutback to upstream spending will have a magnified impact on both reserves and production.

Second, the ESG movement has already made clear its hostility towards the Canadian oil sands. Because of its degraded state, bitumen must be upgraded into crude oil before being refined. This process releases large amounts of additional CO₂ compared with conventional lighter crudes. Furthermore, the Canadian oil sands are either mined or extracted through a process known as steam assisted gravity drainage (SAGD). Both techniques consume additional energy, further adding to the CO₂ output.

Over the past 30 years, the Athabasca oil sands offered the supermajors one of their only attractive upstream investment opportunities. At their peak in 2013–2015, Athabasca proved oil reserves made up 40% of Exxon's total. Similarly, the oil sands made up 35% of Royal Dutch Shell's reserves and 20% of Total's. Only Chevron had less than 10% of its reserves in the oil sands.

Recognizing the intense ESG pressures building against the Canadian oil sands, Royal Dutch Shell sold all its projects, including its 60% ownership in the highly profitable Athabasca Oil Sands Project (AOSP) in May 2017. Total has written down almost all its oil sands investments, including its 50% ownership in the Surmont SAGD project and 25% ownership in the newly commissioned Fort Hills project. Given its carbon reduction goals, Total now views these assets as "stranded" over the next 20 years. Chevron announced it is seriously exploring selling its 20% ownership in the AOSP project, despite the project generating "pretty good cash flow, without needing much capital." Finally, Exxon announced it is writing down all its Canadian oil sand reserves, representing 35% of its total proved oil.

In previous low oil price environments, Exxon wrote down much of its high-cost oil sands reserves, only to add them back once prices recovered. For example, in 2016 they wrote off 3.7 bn barrels of oil sands reserves only to add the same amount back once prices recovered in 2018. A comparable volume of reserve was again written off in 2020 and although the reason cited was low prices, we would be surprised if Exxon added them back again given

ESG pressures. Exxon's new directors may force the company to cease investing in their oil sands projects altogether, thereby guaranteeing these assets remain written off permanently.

Between 2010 and 2020, the cost to find and develop oil and gas reserves more than doubled compared with the decade prior. To merely hold reserves and production flat, ever more capital spending is required. What would happen if upstream capital spending instead remained at 2020 levels due to rapidly escalating ESG pressures? Upstream operational results for all four supermajors would be dire. Assuming finding and development costs stayed at \$25 per boe and that capital spending holds steady at ~\$65 bn per year, holding the R/P flat at 9 implies that all four supermajors will shrink significantly.

At the end of 2020, the four supermajors had 43.3 bn boe of proved reserves split between 25.5 bn barrels of oil and 17.8 bn boe of natural gas. Production totaled 13 mm boe per day split 7.7 mm b/d oil and 5.7 mm boe/d natural gas. If capital spending remained at \$65 bn per year through 2030, total proved reserves would fall from 43.3 bn boe to 30.2 bn boe — a reduction of 30%. Oil production would likely fall from 7.7 mm b/d to 5.4 mm b/d while natural production would fall from 5.7 mm boe/d to 3.9 mm boe/d. Under this scenario, reserve replacement would fall from the 2010–2020 average of 85% to only 40% over the 2020–2030 period.

"IN OTHER WORDS, RESTRICTING CAPITAL SPENDING TO 2020 LEVELS WOULD SUCCESSFULLY ACCOMPLISH THE PRIMARY ESG GOAL: THE FOUR SUPERMAJOR ENERGY COMPANIES WOULD SHRINK SIGNIFICANTLY IN TERMS OF PRODUCTION AND RESERVES AND BECOME SHELLS OF THEIR FORMER SELVES."

In other words, restricting capital spending to 2020 levels would successfully accomplish the primary ESG goal: the four supermajor energy companies would shrink significantly in terms of production and reserves and become shells of their former selves.

The only way for the supermajors to maintain their reserves and production is for upstream capital spending to surge. We estimate the four supermajors would need to see upstream spending double to \$125 bn per year just to maintain flat production and reserves.

We believe the supermajors are a good proxy for the entire global oil industry. Unless spending increases, reserves and production will fall. The 2020s will likely be remembered as the decade non-OPEC production rolled over and began its steady decline. Mounting ESG pressures will only make the looming declines that much worse. While the ESG industry can celebrate, the rest of society will suffer the unintended consequences of higher oil prices and a lack of energy security.

2Q 2021 Natural Resource Market Commentary

Commodities and natural resource equities continued their strong upward trajectory in Q2. Commodity prices, as measured by the energy-heavy Goldman Sachs Commodity Index, advanced 15%. The Rogers International Commodity Index which has more agricultural and metal exposure also rose 15%. Natural Resource equities were also strong performers. The S&P North American Natural Resources Sector index, which is heavily weighted toward North American energy stocks, advanced 11%. The S&P Global Natural Resource index, which has heavier weights in agricultural and metal equities, advanced 7%. By comparison, the general stock market, as measured by the S&P 500 stock index, advanced a little over 8%.

Oil continued to lead commodity markets higher. West Texas Intermediate (WTI) crude rose over 24%, while Brent advanced 20%. Since the beginning of the year, WTI advanced

over 50% while Brent advanced over 45%. Energy-related equities were particularly strong. E&P stocks, as measured by the XOP ETF, advanced over 19% during the quarter and over 65% for the year. Oil service stocks, as measured by the OIH ETF, advanced 15% for the quarter and 45% for the year. We remain extremely bullish regarding oil.

Natural gas prices were extremely strong during 2Q 21, rising almost 40%. Because of extremely warm weather back in November and December, US natural gas inventories started the year approximately 250 bcf (or 7%) above five-year averages. Declining supply and a summer that has been 7% warmer than average reduced inventories to a 170 bcf deficit (about 6%) relative to five-year averages. Given the forecast for continued hot weather this summer and our modelling of supply, we believe the inventory deficit will widen as we progress through the beginning of withdrawal season. We remain extremely bullish toward North American natural gas prices and recommend investors maintain investments in companies with high quality natural gas reserves.

Grain markets continued to show strength. Corn led the grain complex higher, surging an additional 28% in 2Q 22. Since the beginning of the year, corn prices advanced almost 50%. The biggest factor leading corn prices higher has been deteriorating growing conditions in the heart of the corn belt in the US. Severe drought conditions now extend over one-third of Iowa, half of Minnesota and most of both North and South Dakota. Growing conditions in Brazil continue to deteriorate as well.

Prolonged dry conditions have produced the worst drought in over a century, leading the Brazilian government to declare a drought alert across the prime corn growing regions of Mato Grosso, Mato Grosso do Sul, Paranaense Goiás. Brazil is the world's third largest corn producer behind the US and China and any disappointments will further stress an already tight market. We believe we have now entered a period of challenging growing conditions that will persist through this decade.

"WE RECOMMEND INVESTORS MAINTAIN SIGNIFICANT EXPOSURE TO EQUITIES WITH AGRICULTURAL POSITIONS."

For the last 30 years, we have experienced an unprecedented streak of excellent growing conditions. Although highly controversial, we believe reduced sunspot activity has already ushered in a period of global cooling which will result in much more challenging growing conditions. We recommend investors maintain significant exposure to equities with agricultural positions. In previous letters, we emphasized global fertilizer producers. Please note that urea prices (a solid form of nitrogen) are now up 75% for the year while phosphate prices are up 60% and potash prices are up over 100%. Both grain prices and fertilizer prices are likely headed significantly higher.

In the agriculture section of this letter, we will analyze global supply and demand trends as well as describe the results of our new research project. One of the most important (and difficult) data points to estimate are crop yields. Crop yields are subject to a huge number of factors, including fertilizer applications, insect infestation and control and constantly improving genetics. However, by far the biggest factor influencing crop yields each year is weather. Even though many consultants (including the USDA) extensively survey and sample farmers' fields, crop yield estimates are notoriously unreliable. For example, last year the USDA estimated US corn yields would reach a new record of 178.4 bu/ac as late as October. Once the crop was in and measured, they revised their estimate down dramatically to 172 bu/ac, taking the market from expected surplus to actual deficit. The cause was sub-optimal weather conditions during the middle of the summer. Following our success modeling US

shale production, we built an artificial neural network to predict US corn crop yields. Although the work is ongoing, we are excited to share our preliminary results with you. Having greater predictive ability around crop yields will help us forecast global supply and demand trends.

Base metal prices continued their advance. Nickel and aluminum advanced almost 15% during the quarter, while copper rose almost 8%. On May 10th 2021, copper hit \$4.88 per pound — the first and thus far only base metal to make a new all-time high. Given copper's strong demand and dearth of new mine supply, we believe the 140% move off the 1Q 2016 lows is only the first leg of a huge copper bull market that will last through most of this decade. We continue to recommend investors maintain sizable exposure to copper related equities.

While gold and silver rallied during 2Q 2021, we still believe precious metals are going through a lengthy consolidation period. During the quarter, gold rose 4% while silver rose 7%. Gold and silver equities also rallied during the quarter. Gold equities, as measured by the GDX ETF, rose 5%, while silver equities, as measured by the SIL ETF, rose almost 8%.

Since peaking in August 2020, gold and silver have drifted lower for over ninth months. Gold is now down almost 15%, while silver has fallen 12%. Last September, we wrote that silver's furious "catch-up" rally between May and August 2020, signaled that both gold and silver were about to go through a lengthy consolidation period.

After going through a massive buying spree between the beginning of 2019 and the middle of 2020, western gold buyers have not yet returned to either the gold or silver market. Meanwhile, anecdotal evidence continues to emerge suggesting lackluster physical demand from both India and China — the world's two largest gold buyers.

If we are correct that western investors will lead the next leg of the bull market, then another 1970s potential parallel should be discussed: how is a gold bull market impacted by rising interest rates? As our readers know, we believe inflation will return with a vengeance in the not too distant future. At some point, the Fed will be forced to raise rates. What impact will this have on gold and silver? Please read our precious metal section to find out more. We continue to believe the consolidation period in precious metals is not yet over and continue to favor investments in oil, natural gas, agriculture and copper related equities.

Spot uranium prices advanced by 4% to \$32.25 per pound, leaving them flat on a year-over-year basis. Term contract prices fell by \$0.25 to \$33.50 per pound, 6% lower than the same time last year. Uranium related equities continued to be strong performers, advancing 14% during 2Q 2021. Year to date, uranium equities have rallied 38% and are 100% higher than the same time last year.

Looking Ahead to a Tight Oil Market

Over the past 18 months, oil markets experienced their largest dislocation in history. Because of COVID-19 restrictions, demand collapsed, and inventories swelled. Prices fell to a previously unthinkable -\$37 per barrel in April 2020 as traders were forced to pay to have crude taken off their hands. At the same time, producers rushed to shut-in production and curtail drilling activity. While investors panicked, we turned to our models and concluded the market would tighten much faster than anyone thought possible. We doubled our oil and gas exposure through 2Q 2020 and have enjoyed the rebound ever since.

"OVER THE PAST 18 MONTHS, OIL MARKETS EXPERIENCED THEIR LARGEST DISLOCATION IN HISTORY."

Our bullish thesis was based on much stronger than consensus demand estimates and ongoing challenges with non-OPEC+ production. We made several predictions — some that were quite radical at the time — and concluded the crude oil market would shift into deficit by summer 2020, causing inventories to normalize as soon as mid-2021.

"SINCE WE FIRST MADE OUR PREDICTION LAST SPRING, INVENTORIES HAVE INDEED FALLEN AT THE FASTEST RATE ON RECORD."

Since we first made our prediction last spring, inventories have indeed fallen at the fastest rate on record. After peaking at 178 mm bbl above 10-year seasonal averages, US core petroleum inventories are now 34 mm bbl below 10-year averages — the lowest reading in nearly two decades. On a global basis, inventories peaked at 388 mm bbl above seasonal averages last June and as of May 2021 are only 40 mm bbl above average. Given recent trends, we believe global inventories are likely turning negative relative to seasonal averages, in line with our original predictions.

FIGURE 4.1 US Core Petroleum Inventories vs. 10-Year Average

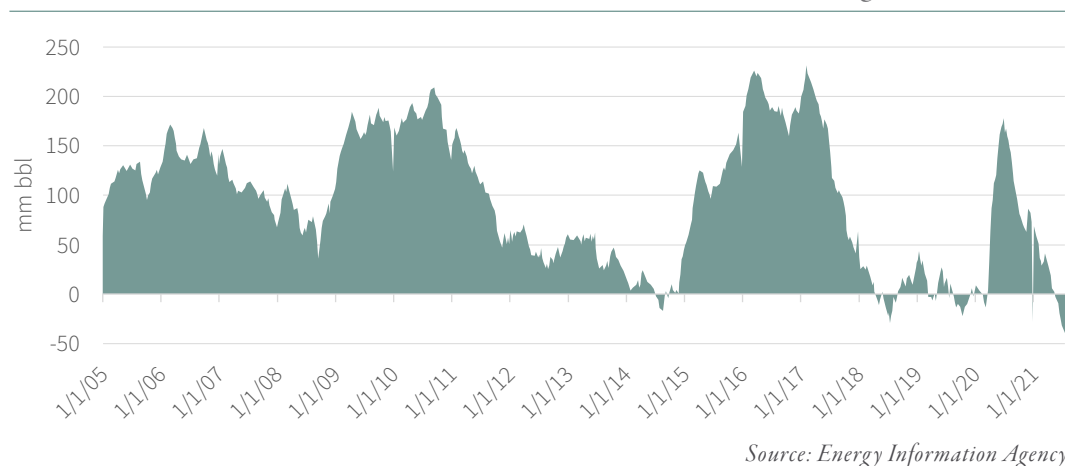
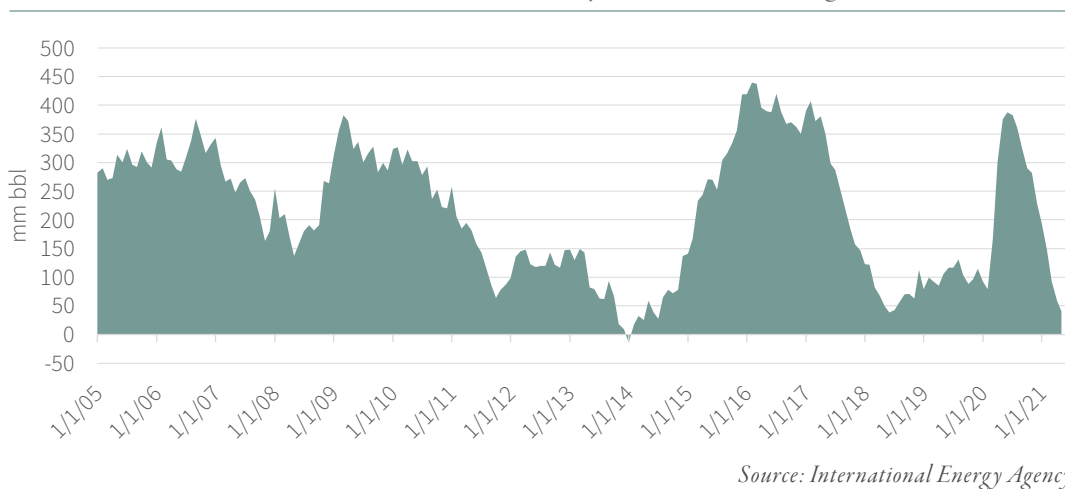


FIGURE 4.2 OECD Petroleum Inventory vs. 10-Year Average



"OVER THE LONGER-TERM, ESG-LED ACTIVIST INVESTORS HAVE ALL BUT ENSURED NON-OPEC PRODUCTION WILL FALL DRAMATICALLY, LEAVING OPEC WITH INCREASED MARKET SHARE AND PRICING POWER."

Global oil markets are very tight. WTI and Brent both trade for \$75 per barrel and the 12-month backwardation (an indication of physical tightness) is approaching its widest reading in years. Oil related equities have been strong performers as well, with the XOP rising nearly 70% over the first half of 2021. Despite the price action in both oil and oil-related equities, investors remain bearish. Shares outstanding of the XOP (a good proxy for generalist investor fund flows) increased less than 10% during the first half of 2021 despite the strong underlying performance. Investors today are fixated on two things: OPEC+ spare

capacity and competition from EVs. While these factors need to be monitored, investors are ignoring how tight oil markets have become and how much tighter they will get as we progress through the rest of 2021 and 2022. Over the longer-term, ESG-led activist investors have all but ensured non-OPEC production will fall dramatically, leaving OPEC with increased market share and pricing power.

In our past letters, we made several predictions regarding global demand, shale production and non-OPEC+ production outside of the US. We based our far different than consensus conclusions on what our proprietary models told us. As with any forward-looking prediction, some things will be right while others will be wrong. We are not embarrassed when we get things wrong, but rather acknowledge that it is an inherent hazard when looking out into the future. With that in mind, we would like to discuss what we got right and what we got wrong in terms of global oil markets over the past 12 months.

Demand

"LAST SUMMER, WE PREDICTED GLOBAL OIL DEMAND WOULD QUICKLY REGAIN ITS PRE-COVID PEAK AS TRAVEL RESTRICTIONS WERE LIFTED. CLEARLY, IN RETROSPECT, WE WERE TOO OPTIMISTIC."

"IN BOTH THE US AND CHINA, WHERE MOST RESTRICTIONS HAVE BEEN LIFTED, OIL DEMAND HAS ALREADY SURPASSED ALL-TIME HIGHS."

Last summer, we predicted global oil demand would quickly regain its pre-COVID peak as travel restrictions were lifted. Clearly, in retrospect, we were too optimistic. As various second and third waves propagated through the fall, winter and spring, many countries chose to reimpose lockdowns and quarantines, leading to ongoing demand disruptions. On the other hand, underlying demand trends have remained extremely strong even in the face of such measures. In many cases, oil demand never fell as sharply as expected and most often surged back faster than anyone believed possible. During the worst of last year's oil rout, analysts questioned whether demand would ever regain its old peak. The IEA laid out a "Sustainable Development Scenario" as recently as October 2020 that concluded oil demand may have peaked in 2019. While we have not yet surpassed the old highs, we are well on our way. In both the US and China, where most restrictions have been lifted, oil demand has already surpassed all-time highs. Neither country is yet back to normal in terms of air travel and so demand will likely continue to surge from here.

In their most recent Oil Market Report, the IEA now predicts 2021 global demand will average 96.4 mm b/d. While this is a dramatic improvement over last year's 91.1 m b/d, it is still a far cry from 2019's 99.7 mm b/d. Furthermore, the 2021 demand figure was revised lower by 600,000 b/d between the IEA's December 2020 and July 2021 reports. While on the surface this is a bearish development, we believe the headline numbers are misleading.

"FIRST, THE 'BALANCING ITEM' AVERAGED A ROBUST 600,000 B/D DURING THE FIRST HALF, IMPLYING THAT COVID RELATED LOCKDOWNS NEVER IMPACTED DEMAND AS MUCH AS THE IEA ESTIMATED IN THEIR DOWNWARD REVISIONS."

First, the "balancing item" averaged a robust 600,000 b/d during the first half, implying that COVID related lockdowns never impacted demand as much as the IEA estimated in their downward revisions. As our readers know, the IEA introduces a balancing item when it cannot get supply, demand, and inventories to properly balance. We have long argued the balancing item represents underestimated demand and historically a large balancing item has been followed by upward demand revisions. We believe this time will be no different. Adding a 600,000 b/d balancing item takes 2021 demand to 97.0 mm b/d, flat with the IEA's projections from December 2020.

Next, the bulk of the disappointment during the first half came from India as COVID-19 spread at an alarming rate. Indian demand was revised down in the first half by over 325,000 b/d or 6%. Removing India and adding the balancing item to the IEA's demand figures suggests the rest of the world outperformed the IEA's expectations for the first half while

projections for the second half are now nearly 600,000 b/d higher than they were in December 2020. Given that Indian case numbers are thankfully falling dramatically, we expect to see a strong rebound there as well.

In their most recent report, the IEA admits that demand surged by over 3 m b/d in June and believes “robust global economic growth, rising vaccination rates and easing social distancing measures will combine to underpin stronger global oil demand for the remainder of the year.” While we agree with the sentiment, we believe this reality is not yet reflected in their demand figures. The IEA currently projects 2022 demand will average 99.5 mm b/d, still below 2019 levels. Instead, we believe ever more countries will surpass their previous demand records and that 2022 demand will need to be revised higher by nearly 1 mm b/d.

Non-OPEC+ ex US Supply

We have long argued that non-OPEC+ supply outside of the US shales would suffer ongoing challenges. Declines in both capital spending and new projects cannot overcome base declines and so non-OPEC+ supply growth over the last decade has stagnated. We believe this will only get worse now that ESG-led activist investors are pushing for change at the energy supermajors.

At the end of last year, the IEA projected that non-OPEC+ ex US production would grow by 1 m b/d in 2021 — a figure we strongly disagreed with. In our 4Q 2020 letter we argued that production from this group could instead decline by as much as 500,000 b/d this year.

The data has largely confirmed our views, although it has been missed by most analysts. Since their October 2020 report, the IEA has revised its estimates for 2020 non-OPEC+ ex US production lower by 150,000 b/d. Next, the agency revised production from the group lower for the first half of 2021 by a massive 760,000 b/d — from 37.1 m b/d in their October report to 36.4 m b/d today. At the same time however, the IEA revised its second half 2021 non-OPEC+ ex US production estimate higher by 160,000 b/d. We believe it is a mistake to revise second half estimates higher when first half estimates disappointed so dramatically.

The IEA has done this several times in the past. The last time non-OPEC production disappointed was in the mid-2000s. At that time, we wrote extensively of the problems facing supply and how OPEC would continue to gain market share. Back then, the IEA would also revise supply lower once actual data came in during the first half of the year, while simultaneously offsetting the revisions by increasing its second half estimates. When the second half production failed to materialize, they would wait until the following year and revise the previous year’s numbers lower. To cap off the bizarre exercise, analysts would then claim that the IEA had revised year-on-year growth *higher*, when all that had happened was that the prior year’s figure was revised lower.

We believe a similar dynamic is taking place today. Looking only at the full-year figures, the IEA now projects non-OPEC+ ex US production will grow by 1 m b/d in 2021 — unchanged from its original predictions last year. What has changed however is that 2020 actual production was revised lower as was 1H2021 production (the latter materially so). We believe these disappointments will continue as we progress through the year and into 2022.

US Production

Shale production has held up better than we expected. At the end of last year, we predicted

shale production would experience sustained sequential declines unless activity increased dramatically. Since then, shale production has largely been flat, continuing a trend that began last August. While the shales have not been able to grow, they have been able to arrest their declines better than we anticipated. Shale's resilience is explained entirely by increased activity. As oil prices have moved sharply higher, shale producers have increased their completion levels, mostly in the Permian. Monthly shale completions increased from 600 at the end of 2020 to nearly 818 by June 2021, an increase of 35%. Adjusting our neural network for the increased completions explains all the discrepancy.

The completions came mostly from so-called DUCs or wells that were drilled but uncompleted. During last summer's dislocation, companies chose to continue drilling when contractually obligated but opted to defer completing wells to reduce capital expenditures. As the crisis passed and oil prices moved higher, the companies rushed to bring the backlog online. The DUC inventory fell by 1,500 wells or 20% over the first half of the year to its lowest level since 2018.

While DUC activity rebounded, drilling activity has been much slower to respond. As you can see, there is a very tight relationship between oil prices and the rig count. Given the recent rally in crude, the rig count would normally have increased to between 800 and 1,000 operating rigs. Instead, the rig count remains below 400 — a level more strongly associated with \$30 oil than \$75.

"GIVEN THE RECENT RALLY IN CRUDE, THE RIG COUNT WOULD NORMALLY HAVE INCREASED TO BETWEEN 800 AND 1,000 OPERATING RIGS. INSTEAD, THE RIG COUNT REMAINS BELOW 400 — A LEVEL MORE STRONGLY ASSOCIATED WITH \$30 OIL THAN \$75."

FIGURE 5 Oil Rigs vs. Oil Price



Source: Baker Hughes and Bloomberg.

We believe companies have been slow to put rigs back to work because they lack high quality Tier 1 drilling inventory. As we have discussed in these letters, our neural network tells us the E&P companies have been high grading their inventory for years and have now largely developed their best areas. Whereas in previous cycles, the companies would have had enough economic drilling opportunities at today's oil price to sustain an 800 rig count, today it is impossible to sustain half that activity. If we are correct, then production risks falling again once the DUC inventory normalizes.

"THE ONLY MATERIAL SOURCE OF NON-OPEC GROWTH OVER THE PAST DECADE IS LIKELY GONE."

Using the most recent activity levels, we now believe shale production will remain mostly flat throughout the rest of the year. As a result, year-on-year shale production will not decline by 650,000 b/d as previously modeled but instead fall by 400,000 b/d. Instead of falling sequentially by ~60,000 b/d per month as previously expected in the second half, we now believe shale production will be mostly flat from the June 2021 rate of 7.7 m b/d.

As we mentioned, when you forecast the future, you are bound to get some things right and other things wrong. High prices have encouraged companies to complete their DUC inventory and in turn that has allowed shale production to arrest its declines better than we originally anticipated. However, the lack of rebound in the rig count is certainly telling. Moreover, it is worth noting that even with the recent increase in activity, every basin other than the Permian is now in sustained sequential decline — something we predicted last year.

We continue to believe the best days of the shales are now behind them. There will always be a certain degree of volatility in the monthly numbers, however we do not expect production to ever grow again the way it has in the past. The only material source of non-OPEC growth over the past decade is likely gone.

Balances Going Forward

Despite the dramatic inventory draws thus far in 2021, many analysts remain concerned about OPEC spare capacity and its ability to overwhelm balances. We believe this concern is misguided and that the current deficit is set to get worse.

The IEA currently projects second-half demand to average 98.75 m b/d while non-OPEC+ production (including OPEC NGLs that are outside of the quota system) will average 54.8 m b/d. This would leave the call on OPEC+ crude at 44 m b/d. In June, OPEC+ produced at 41.5 m b/d, implying inventories would continue to draw by 2.5 m b/d, were the group to hold production flat. As we have discussed, we believe the recent ~700,000 b/d balancing item is understated demand and will persist into the second half of the year. Moreover, as explained above, we believe the non-OPEC+ ex US figures are horribly overstated by as much as 600,000 b/d in the second half, based upon revisions to 1H figures. Taken together with the balancing item, we believe the 2H2021 call on OPEC+ crude could reach 45.2 mm b/d, or nearly 4 m b/d higher than June levels.

Investors were concerned when the recent OPEC+ meeting took longer to conclude than expected. The UAE pushed for a 450,000 b/d higher production quota beginning in April 2022 in exchange for extending production cuts through the end of next year. An agreement was ultimately reached whereby OPEC+ would begin to increase production in August 2021 by 400,000 b/d per month. Next April, the UAE's production quotas will be reset higher, while the production quota framework has been extended until next December. Under this new scenario, the oil market would remain firmly in deficit through the second half of 2021.

Looking beyond the second half, we are confronted with a situation we have never experienced before in global oil markets. It is becoming clear to us that demand will regain its old peak once COVID-19 related restrictions are fully lifted. Demand has surged far beyond people's expectations in the US and China (where restrictions are mostly lifted) and we see no reason this will not continue. By the end of 2022, in conjunction with demand's seasonal high point, we believe global oil demand could eclipse old highs and reach 103 m b/d. The

IEA currently believes 4Q 2022 non-OPEC+ production will reach 56.6 mm b/d which would represent 1.3 mm b/d of growth over 4Q 2021. Since we believe the 4Q 2021 figure will be revised down by as much as 600,000 b/d and that future non-OPEC+ growth will be hard to come by, the 4Q 2022 estimate might be overstated by 1.5–2 mm b/d. In this situation, the call on OPEC+ crude would approach 48.5 mm b/d — leaving the cartel with next to no spare capacity. Although we admit that this forecast is aggressive, the direction is what is important. As demand normalizes and resumes its growth trajectory and non-OPEC+ continues to disappoint both in the US and abroad, it will quickly become clear that OPEC+ spare capacity will be exhausted at some point within the next two years.

"AS THE MARKET BEGINS TO REALIZE HOW TIGHT BALANCES TRULY ARE AND THAT OPEC SPARE CAPACITY CAN BE ENTIRELY ABSORBED BY DEMAND GROWTH AND STAGNATING NON-OPEC+ SUPPLY, INVESTOR PSYCHOLOGY WILL SHIFT DRAMATICALLY."

"IF WE ARE CORRECT, INVENTORIES RUN THE RISK OF STARTING THE WITHDRAWAL SEASON AT THE SECOND LOWEST LEVEL IN FIFTEEN YEARS."

As the market begins to realize how tight balances truly are and that OPEC spare capacity can be entirely absorbed by demand growth and stagnating non-OPEC+ supply, investor psychology will shift dramatically.

North American Gas Markets Now in Deficit

Tightness in the US natural gas market is beginning to manifest itself in low inventory levels. After having started the year at a 200 bcf surplus to the five-year seasonal average, US inventories now stand at nearly a 200 bcf deficit. Given the current trajectory, our models suggest we could end the injection season at 3.2 tcf of gas representing a 400 bcf deficit, or 700 bn cubic feet lower than the same time last year. If we are correct, inventories run the risk of starting the withdrawal season at the second lowest level in fifteen years. At that point, any bout of cold weather this coming winter would likely lead to a price spike.

Prices have been firming and currently stand at \$3.60 per mcf, over 40% higher than the start of the year and more than double this time last year. In fact, Henry Hub natural gas, which normally experiences price spikes in the winter due to heating demand, is at its highest seasonal level since 2014. Despite the rally, there has been little in the way of a drilling response. According to the Baker Hughes rig count, only 30 rigs have been put back to work since bottoming at 68 in July 2020. As of today, 100 rigs are drilling for gas compared with 200 as recently as 2019.

Since their initial development in the early 2000s, the US shale gas fields have completely overwhelmed US gas markets. Between 2007 and 2020, shale production grew by an incredible 68 bcf/d on a starting base of 50 bcf/d. Over that time, the shales represented 150% of total US production growth, with conventional supply declining steadily. Notably, the Marcellus (in Pennsylvania) and associated gas from the Permian (in Texas) were responsible for nearly 70% of that increase. In 2019, our neural network indicated that both plays were in the early stages of resource exhaustion. We predicted both basins would have a hard time growing at the same rate as in prior years and may actually begin to decline.

Our models appear to be correct. Between December 2019 and June 2021, the Marcellus has been flat while the Permian has added only 1.1 bcf/d. To put these figures into perspective, over the eighteen months between June 2018 and December 2019, the Marcellus added 6.5 bcf/d while the Permian added 5.5 bcf/d. In other words, Marcellus growth declined by 98% while Permian growth fell by 80%. While COVID certainly impacted drilling activity, recent production trends have not improved. Year to date, production from the Marcellus and Permian combined is down 250 mmcf/d.

If the shales stop growing, total US production would decline quite quickly. For example, total US dry gas production peaked in December 2019 at 97 bcf/d. As of April (the most recent month with complete data), US supply was down 4.5 bcf/d or nearly 5% to 92.5 bcf/d. Given that preliminary data suggests the shales declined between April and June, it seems almost certain total US dry gas production has continued to decline as well.

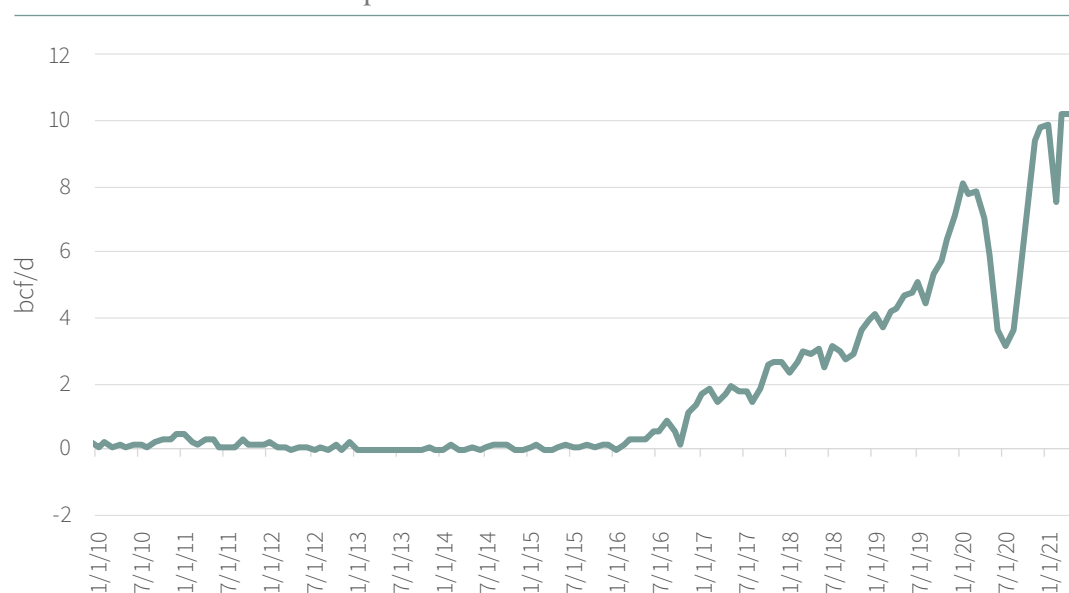
We now have another set of anecdotal data points suggesting the Marcellus is suffering the early stages of resource exhaustion. Two major Marcellus gas producers made significant acquisitions outside the basin during Q2. It is our belief they did so to bolster their quickly eroding inventory of remaining high quality drilling locations. On May 24th, 2021, Cabot Oil and Gas, long believed to be the best Marcellus operator, diversified into the Permian by merging with Cimarex Energy for \$9 bn including debt. Our models have always suggested that, while Cabot had the best acreage in the gassier portion of the northeast Marcellus, its drilling inventory was not as extensive as most investors believed. Our neural network confirmed this view. We found it extremely telling when Cabot announced their unexpected merger despite never having discussed diversifying outside of the basin.

On June 2nd 2021, Southwestern Energy acquired private Haynesville operator Indigo Natural Resources for \$2.7 bn. Just as with Cabot, the market was not expecting a material acquisition that diversified exposure away from the Marcellus. What is interesting about Southwestern is that they were the first mover in the Fayetteville shale in Arkansas in the early 2000s and an early pioneer in shale gas overall. They diversified basins by acquiring Marcellus assets from Chesapeake in 2014, making them one of the few operators to have fully developed a basin and then successfully reoriented into a new play. Perhaps they sense similarities between the Marcellus today and the Fayetteville in 2014.

While supply has been challenged, demand remains extremely strong. Global demand for LNG is robust as weather events and strong economic demand from China and others has led to surging prices and tight markets. Notably, high temperatures across Asia have led to strong demand for electricity to power air conditioning in Bangladesh and India (a sign of the S-Curve). At the same time, Brazilian drought conditions have resulted in lower-than-normal hydro availability. Global spot LNG prices averaged \$14 per mmbtu, the highest levels since 2013 and above oil-linked parity. Exported US LNG has clearly had no problem being absorbed in the global market, despite having grown from nothing as recently as 2017 to an incredible 10 bcf/d today — up 3 bcf/d in the past year alone. We have long argued that global demand for LNG was much greater than anyone believed possible. As emerging countries become wealthier, they seek cleaner forms of power of which natural gas is the most effective. Gas bears have long argued that excess natural gas supply will eventually break the linkage between global LNG prices and oil prices that has long been central to long-term LNG contracts. The fact that spot LNG today trades above its oil-linked parity suggests to us the market remains very tight. We continue to believe that the global seaborne gas market will continue to absorb new capacity from the US going forward.

The main challenge faced by US natural gas has been the unrelenting growth of the Marcellus and Permian. If we are correct and both plays are entering the early stages of exhaustion, then a new gas bull market has likely started. Production data seems to suggest we are correct and now anecdotal evidence among the producers points that way as well. Inventories are now beginning to get tight relative to seasonal averages and the US will likely enter the withdrawal season vulnerable to any bout of colder-than-normal weather. The great bull market in natural gas has begun.

FIGURE 6 US LNG Exports



Source: Energy Information Agency.

Corn Yields Likely to Disappoint

Grain markets continued to tighten in 2Q 2021 as grain prices (notably corn) advanced strongly. Strength in Chinese corn and ethanol demand prompted further bullish revisions to both the May and June USDA WASDE reports. Earlier in the year, the USDA estimated that US corn ending stocks for the 2020–2021 growing season had dropped to 1.5 bn bushels, the lowest level since the drought year of 2012–2013. Since then, corn carryout stocks have been continuously revised even lower.

In the April WASDE report, domestic corn demand was revised higher by 25 mm bushels while ethanol and export demand (almost all Chinese related) were revised up by 125 mm bushels. As a result, the USDA reduced its estimate of 2020–2021 corn ending stocks by 150 mm bushels to 1.3 bn. But further downward revisions were still to come. In the May WASDE report, export demand was revised up by an additional 100 mm bushels leading to an equal offsetting reduction in ending stocks. Once again, most of the revisions were due to higher-than-expected Chinese demand. Finally, in the June WASDE report, export and ethanol demand were revised yet again, this time by 150 mm bushels, leaving the expected corn carryout at 1.1 bn bushels — a level approaching dangerous territory. In the past 45 years, there have only been three years with lower carryout readings: 1996, 2003 and 2012.

What makes these carryout figures so impressive is how quickly they have collapsed. As late as June 2020, the USDA was still predicting a “bin-busting” 3.3 bn bushel carryout level — a glut not seen since the late 1980s. In our 4Q 2020 letter, we discussed the factors that have pushed corn carryout projections from near-record highs to dangerous lows in a few short months. Since we wrote, the data continues to confirm our analysis.

Soybean carryout projections have also been reduced, but not as dramatically as corn. As late as July 2020, the USDA estimated a 425 mm bushel carryout for the 2020–2021 growing year. While the estimates for acres planted, acres harvested and realized yields were all highly accurate, the USDA underestimated soybean demand (much like it did with corn) by almost

230 mm bushels. Once again, the source of the error was Chinese demand. In the June 2021 WASDE report, 2020–2021 soybean carryout levels had been lowered to a mere 135 mm bushels. Just as with corn, this would represent the fourth lowest reading in nearly 50 years.

Given the dangerously low carryout levels and robust demand in both corn and soybean markets, weather conditions and their impact on yields have become critically important. The USDA estimates that US corn demand will fall by 250 mm bushels in the upcoming 2021–2022 crop season, driven primarily by a 400 mm bu drop in exports. Total demand for US corn is expected to reach 14.8 bn bu. Even with reduced export demand, yields must reach all-time high levels to avoid the market becoming even tighter. Preliminary estimates of planted corn acres disappointed when they were first released in May. The USDA now assumes that 91.1 m acres were planted and 83.5 m acres will be harvested with an all-time record yield of 179.5 bu/ac, producing a US corn crop of almost 15 bn bu.

Even assuming record yields, the projected 2021–2022 corn carryout would approach 1.4 bn bu — only slightly above critical levels. The USDA's yield assumption is a significant 1.1 bu/ac increase over last year's initial estimates. However, as we previously discussed, actual yields for the 2020 US corn crop fell significantly short of expectations. Subtle, little noticed weather conditions in the middle of last summer significantly impacted yields. Actual yields came in at 172 bu/ac — a massive reduction of 4.2 bu/ac compared with original expectations. Interestingly, the USDA only recognized the magnitude of the yield disappointment after most of the 2020 corn crop had been harvested.

We believe similar weather-related challenges are being missed again this year. If adverse weather continues to grip the corn belt this summer, the expectation of record-high corn yields could once again be wildly off the mark. Extreme drought conditions now exist across the Western corn belt. If corn yields fell back to last year's 172 bu/ac (still historically very high), the US corn harvest would only reach 14.4 bn bu and the 2021–2022 carryout would fall to 730 mm bushels, putting extreme upward pressure on prices. If yields fell to 163 bu/ac, the US corn carryout would approach zero — an unthinkable situation. And remember, a realized corn yield of 163 or below is completely in the realm of historical possibility. US corn yields averaged only 145 and 159 bu/ac in 2011 and 2013 respectively; in the drought year of 2012 yields got as low as 123 bu/ac.

Trying to estimate corn yields over the next six months has become critical. For the US corn market to return to even a slight surplus, corn yields will need to reach record high yields. Given current weather conditions, we believe this is unlikely. Instead, the corn market will likely remain very tight.

Estimating corn yields is always a critical part of predicting corn prices and this is particularly true this year given the low corn carryout inventory levels. As a result, we decided to move forward with a project we have been thinking about for several months: developing a neural network to help predict crop yields. In 2019, we first wrote about our success in developing an artificial neural network to assess shale productivity. We were very impressed with how accurate our purpose-built neural network was at identifying the underlying drivers of improved shale oil drilling productivity and immediately thought of other uses for the advanced statistical technique. Trying to predict crop yields was at the top of our list.

In many ways, crop yields are a much more challenging problem than shale productivity. A shale well depends primarily on location and drilling technique. On the other hand, crop

yields depend not only on location and weather, but on the progression of weather. Too much or too little rain at certain moments has a larger impact than at other moments. Moreover, even identical growing conditions can generate wildly different yields — there is an underlying uncertainty and variability to the results.

We wanted to capture that uncertainty and decided to build an artificial neural network that would explicitly incorporate the uncertainty. We also built the model so that it could be updated throughout the year. That way, we could make a prediction at the start of growing season. This early prediction would be inherently “noisy” since the model did not yet know what weather would have in store. As the summer progressed, the model could be updated with additional weather and crop condition data and the prediction would evolve in real time. Not only would the prediction dynamically update as new data was available, but ideally the confidence band around the estimate would tighten as well until we reached the end of the growing season at which point, we would have a fairly precise yield estimate that incorporated all of the season’s data crop, temperature and moisture data.

The task is difficult and the project is ongoing. We are now taking steps to ensure the model is not “overfitting” the data (a common pitfall with artificial neural networks). This occurs when extremely complex statistical models “learn” by simply memorizing the data used for training instead of trying to “understand” the underlying mechanics of the system.

As the model stands today (and please keep in mind that this is subject to revision as we improve upon the design and as more data becomes available), US corn yields seem to be tracking worse than the 2017–2018 growing season which resulted in a 177 bu/ac yield. Instead, projected yields seem to be in a range around the 2019–2020 and the 2020–2021 growing seasons which resulted in yields of 168 and 172 bu/ac respectively. As of today, given how new the model is, we would err on the side of caution and predict yields at the higher end of that range, in line with last year’s results. In any case, our models tell us that, as of now, it is unlikely we will reach the 179 bu/ac the USDA is currently expecting and that the market will be tighter than most investors realize.

The US soybean market is in a similar situation. The USDA projects the 2021 US soybean yield will reach last year’s very high level of 50.8 bu/ac. Even with such yields, the 2021–2022 carryout is expected to only grow by 20 mm bu to reach 155 mm bu. Moreover, the USDA projects US soybean exports will fall by a large 200 mm bu — a highly unlikely scenario. Like corn, if soybean yields fell by only 1.6 bu/ac to 49.2 bu/ac, carryout levels would fall to zero — again a very stressful situation that would put extreme pressures on prices.

Have soybean yields lower than 49.2 bushels been experienced in our historical reference period? Yes. In 2011 and 2013, US soybean yields were 42 and 44 bu/ac, respectively, while in the 2012 drought conditions, the yield fell to 40 bu/ac. Thus far, weather conditions in the heart of the US soybean growing region have been much more favorable than for corn, leaving us less concerned. However, we must closely monitor weather patterns in these areas to help assess yield. Just like with corn, strong demand and low carryout levels have left the market sensitive to any weather disruptions.

Gold and Silver Still Have Time

While we believe a huge precious metals bull market lies in front of us, we must also be aware

that challenges remain over the medium term. Since the beginning of 2021, the average gold stock is down about 10%; in comparison, the average energy stock is up over 60%. The question for precious metals investors is how long this period of price consolidation will last.

We believe the current consolidation period is not yet over. We have long argued the upcoming bull market will be driven by western investors, as it was back in the 1970s. In contrast, the bull market between 2000 and 2012 was driven by eastern buyers who believed gold was a cheap asset class that had to be accumulated and held.

Back in 2000, the US and Europe consumed approximately 700 tonnes of gold combined. By 2012, as the first leg of the gold bull market was ending, their consumption had fallen to 460 tonnes. Gold had gone from \$250 per ounce to \$1,900 per ounce while western consumption had fallen. In other words, there was no participation from western buyers even though gold prices advanced over seven-fold. Over the same period, India and China went from consuming 1,150 tonnes combined in 2000 to 2,400 tonnes by 2013. Clearly, the major source of buying during the last gold bull market came from the East with no net participation from the West.

A gold bear could make the case that eastern demand has now been satisfied and data from the World Gold Council (WGC) could confirm this view. Indian and Chinese gold demand peaked in 2011 and 2013, respectively, and by 2019 had fallen by over 30%. More recent data suggests eastern physical demand remains lackluster today. If the gold market had to rely exclusively on eastern demand, we would have to accept that the bull market move over the last two decades was about to end.

However, because of the massive amounts of money printed by global central banks since 2008, huge inflationary problems will emerge as we progress through this decade. Western investors will aggressively seek out assets that will not only protect them from inflation but will offer speculative gains in an inflationary environment — very much like what happened in the 1970s.

The western investor's buying power is huge — a small allocation shift could send gold prices much higher. Monitoring the flow of western capital into physical gold will be critical in determining when the corrective phase ends and the new bull market begins.

As of today, the flow of western capital into physical gold remains subdued. Western gold buyers (best represented by the 16 physical gold ETFs we track) went on a huge buying spree between October 2018 and October 2020. Over the period, these ETFs accumulated 1,360 tonnes of gold, increasing their holdings by 65% in only two years. In silver, the behavior of western buyers was even more impressive. Starting in May 2019 (much later than gold), western accumulation began to surge and over the next 18 months, the nine ETFs we follow accumulated 18,000 tonnes of silver — an increase of 115%.

Since October 2020, western investors turned from gold buyers to sellers. The physical gold ETFs we track shed 360 tonnes over the last nine months. The silver ETFs also started to shed silver in October 2020, but following the Reddit silver buying spree of January 2021, physical holdings surged. As we discussed in our 1Q 2021 letter, the attempted short squeeze was ultimately unsuccessful and since then all the accumulated silver has been liquidated.

As we discussed in our 1Q 2021 letter, an interesting divergence has now taken place between the gold and silver ETFs. Gold ETF holdings are now approximately 350 tonnes below their

"THE ONGOING LACK OF WESTERN INTEREST IN PHYSICAL GOLD AND SILVER LEADS US TO BELIEVE THE CURRENT CORRECTIVE PHASE, WHICH STARTED LAST SUMMER, IS NOT OVER."

October 2020 peak while silver ETF holdings are now 30 tonnes higher than their October 2020 peak. We remain convinced inflationary expectations will surge in the next 12 months, despite the ongoing bond market complacency. Perhaps silver, which has a high degree of inflation-sensitivity, is telling us that problems are about to emerge.

The ongoing lack of western interest in physical gold and silver leads us to believe the current corrective phase, which started last summer, is not over.

If the upcoming gold bull market is to be dominated by western investors, we feel it is important to discuss another issue that could very well extend the corrective period we are now experiencing in both gold and silver: how will prices react to rising interest rates? Let's look at how gold and silver reacted to rising interest rates back between the fall of 1973 and the summer of 1974.

The bull market in both gold and silver started in 1970 with gold at \$35 and silver at \$1.75 per ounce. After Nixon suspended convertibility of the US dollar into gold in August 1971, both gold and silver prices entered huge bull markets. By 1974, gold had reached \$190 per ounce while silver had spiked to almost \$7. The Arab oil embargo started in October of 1973 and precipitated a four-fold increase in oil prices that led the US Federal Reserve to aggressively raise interest rates. The Fed Funds rate which stood slightly above 5% at the start of 1973 had increased to 13% by the summer of 1974.

Rising interest rates temporarily halted the bull market in both gold and silver. After peaking in the first quarter of 1974, gold and silver spent the next two-and-a-half years correcting. Gold eventually bottomed in August 1976 at \$105 per ounce — a retracement of 45% from its 1974 peak. Silver bottomed at \$3.80 in January 1976 — 45% below its 1974 peak.

After peaking in 1974 at 13%, the Fed Funds rate fell back to 6% by 1Q 1975; however It took another two years for the bull market in gold and silver to resume with a vengeance.

We believe we are about to enter a period of increased inflationary expectations. As a result, we believe the Fed will eventually be forced to raise rates. Given the experience of the mid-1970s, we remain cautious of the near-term impact on gold and silver.

We still believe the corrective phase in both gold and silver is not over. The precious metal bull market awaits, but we believe its next leg has not yet come.

The Early Success of Small Modular Reactors

Uranium stocks sold off in mid-June as news outlets reported a possible leak at the Taishan Chinese reactor, a joint venture with Électricité de France (EDF). The facility later acknowledged that while there had been damage to the fuel rod casings, there had been no radioactive leak. Fuel rod casings are one of three redundant methods for containing radioactivity in modern reactors and subsequent reports acknowledged that radiation levels never exceeded safe operating parameters.

In the US, President Biden initially disappointed the uranium market when his proposed budget did not include funds for the strategic uranium reserve, as had been expected. However, soon after the announcement, the administration clarified that the reserve would be funded through already-appropriated funding and did not require an explicit line-item in the budget.

The most important developments over the past several months involved progress with so-called small modular reactors (SMRs). Many energy analysts believe SMRs represent the future of nuclear power given they are smaller and more manageable with lower capital requirements. On June 2nd, TerraPower and PacifiCorp announced plans to advance their SMR project in Wyoming. The project is notable because of its backer: TerraPower was founded by Bill Gates, and PacificCorp is owned by Warren Buffett's Berkshire Hathaway. The project will consist of a 345 MW reactor joined with a molten-salt-based energy storage system providing peak output of 500 MW. It is expected to cost \$1 bn.

Ontario Power Generation (OPG) announced they will imminently select a design for their own 300 MW SMR project that is expected to be operational by 2028. OPG budgeted \$3 bn for the project — the first Canadian nuclear plant built in over thirty years.

As we have discussed in the past, nuclear power demand growth will come mostly from the developing world, notably China. On July 13th, China commenced construction of the world's first land-based SMR. Linglong One is a 125 MW reactor located on the island of Hainan that is expected to be operational by 2026. The reactor is based upon the ACP100 design — the first SMR design to be approved by the International Atomic Energy Agency (IAEA) in 2016.

Meanwhile, the Dutch government is moving forward with its long-term plan for new nuclear generating capacity. Following a widespread backlash against renewable power, a motion was adopted in the Dutch House of Representatives in late 2020 calling for a study into new nuclear power plants in the Netherlands. KPMG was engaged to prepare the study and ultimately consulted with 41 various contractors, operators and investors. The report was made public on July 8th and showed support for various solutions. The next step will be a further study of how nuclear power can be used to mitigate carbon emissions. The Netherlands is a fascinating example of a country dealing with the inherent limitations of wind and solar generation and looking at nuclear power as the only feasible way of providing carbon free baseload power.

Lastly, in an interesting turn of events, several bitcoin mining operators announced partnerships with SMR developers to provide carbon-free electricity. Bitcoin mining has come under scrutiny over its substantial energy requirements. Were bitcoin mining a country, it would be the 25th largest electricity consumer in the world. As a result, major bitcoin operators have become sensitive to their carbon emissions. Instead of looking at renewable sources, with their inherent limitations (please see our 4Q 2020 letter), several bitcoin mining operators have partnered with nuclear power providers. Bitcoin miners are nothing if not economically sensitive. Given their need to reliably consume huge amounts of power and their newfound desire to reduce carbon emissions, it is telling they chose nuclear power as their preferred solution.

Earnings Power of Copper Miners

Copper made a new all-time high during the quarter. After bottoming in January 2016 at \$1.94 per pound, copper rallied 150% to reach \$4.77 on May 11th 2021. Although copper pulled back somewhat, it remains at \$4.32 — the highest level in a decade. Far from being over, we believe this copper bull market has just started. As we have written in the past, we

believe that the current cycle will ultimately take copper prices above \$10 per pound. Although this may sound outlandish, copper rallied seven-fold from its 1999 bottom of \$0.61 to its 2011 high of \$4.57 per pound. Our models tell us the fundamentals are much better today than they were during the last bull market. Copper stocks have been strong performers as well. The average copper mining stock, as measured by the COPX ETF, is up nearly 100% year-on-year and 20% year-to-date.

Generalist investors are beginning to take notice and are establishing positions in copper mining equities, helping push prices higher. We have noted in the past how investor interest across the natural resource equity space has remained muted despite prolonged periods of very strong performance over the last two years. This has been particularly true with gold and energy related equities. Flow of funds into the various energy and precious metal equities ETFs have been de minimis, which tends to be a good proxy for investor interest. The same has not been true for copper stocks. Shares outstanding of the COPX are up 319% so far this year and 640% compared with the same time last year, as investors have rushed into the space. By comparison, even though E&P stocks are up 66% year-to-date and nearly 100% year-on-year, shares outstanding of the XOP ETF are flat.

Thus far, most investors have been attracted to the copper equities due to copper's robust demand outlook. We have explained in these letters for several years how renewable energy and electric vehicles are both extremely copper intensive. Furthermore, several countries still must add large volumes of copper to their installed base to meet demand for things like electricity distribution. Despite COVID related disruptions, 2020 was an extremely strong year for copper demand. According to the most recent data from the World Bureau of Metal Statistics, global refined copper demand grew by 900,000 tonnes — the fastest rate since 2014. While many countries, notably India, experienced weak demand as construction and power projects were delayed due to shutdowns, Chinese demand surged by 1.7 mm tonnes. While some copper bears believe China is overconsuming, we believe otherwise. Many analysts compare annual copper consumption with real GDP and conclude that since China consumes over 50% of the world's refined copper but does not generate 50% of the world's GDP it must be overconsuming and potentially even stockpiling.

We prefer to look instead at the cumulative installed copper in an economy compared with its wealth and based upon this metric, we believe Chinese demand will continue to accelerate for the next several years. Ultimately, it is possible that China will need to consume nearly 75% of global supply to install enough copper to support a nascent middle-income economy. We first presented this argument in 2014, when Chinese copper demand represented 45% of global demand. Last year, China represented 58% of global demand; we believe there is further to go. For the first four months of 2021, Chinese consumption looks to have grown another 100,000 tonnes and we expect this will continue. Indian demand, on the other hand, was weak in 2020, falling by 95,000 tonnes, as COVID disruptions took a larger toll. Over the first four months of 2021, Indian demand stabilized and is running flat. We will continue to monitor the situation but would expect demand to move higher as deferred projects are restarted this year and next.

Most of the research reports, news articles and investor letters we have read recommending copper investments have focused primarily on these bullish demand trends. While we believe the demand side remains extremely bright, we continue to think the next leg of the bull market will come once investors realize the widespread supply challenges ahead.

As we discussed extensively in our 1Q 2021 letter, there has been a dearth of new copper discoveries and mine development capital spending over the past decade. Moreover, since 2000, most reserve additions have come from simply lowering the cut-off grade and mining lower quality ore as prices moved higher. As we argued in our last letter, we do not believe this will be possible for geological reasons (i.e., log-normal grade distributions) this cycle. As copper prices continue to rise, investors will realize new supply is unlikely to come anytime soon. While new projects are coming online in the DRC, Panama and Mongolia, these will only offset depletion at other existing mines, resulting in muted overall mine supply growth. Last year, copper mine supply fell by 80,000 tonnes compared with the year before, driven mostly by Chile. Most of the disappointment was related to COVID-19 mine shutdowns and will likely come back. However, it is interesting to note that supply has been slower to restart than expected. For example, over the first four months of 2021, Chilean mine supply is only up 30,000 tonnes.

Two geopolitical events occurred in 2Q 2021 that could negatively impact mine supply going forward. In Peru, Pedro Castillo won a contested election running on a socialist platform that includes a 70% tax on copper mining profits. Following Peru's lead, Chile has proposed legislation that would see copper mine profits taxed at 75%. While these new taxes have not yet been enacted, they are quickly gaining support in Peru and Chile, the first and second largest copper producing countries. Such legislation would further restrict capital spending and likely lead to supply disappointments in the future.

We continue to recommend exposure to high-quality copper related mining equities. Over the past several weeks, copper stocks have consolidated last year's rally and have retraced by 22%. This simply presents a more attractive entry point. Despite having found support from generalist investors, we continue to believe the true potential of many copper equities is being overlooked. While we do not usually talk about individual stocks, we want to highlight a statistic about Freeport McMoRan (a copper miner we own) that demonstrates the potential. Freeport is a bellwether copper stock that operates Grasberg, the largest copper and gold mine in the world in Indonesia — a mine we had the chance to visit on several occasions. While most investors are familiar with Freeport, few we have spoken to realize how much profit it stands to earn if copper prices remain high. Were copper to rally to \$5 per pound (and remember, we believe this cycle will see prices above \$10), Freeport stands to generate \$14 bn in EBITDA. By comparison, Visa generated \$15 bn in EBITDA in 2020. Freeport's enterprise value stands at \$63 bn, compared with \$500 bn for Visa. As investors begin to appreciate the earnings potential of some of these names, we think they will accelerate their purchases of the stocks materially.

Copper continues to be our preferred base metal investment and one of our highest conviction themes overall.