Managing Partners:
LEIGH R. GOEHRING
ADAM A. ROZENCWAJG

IGNORING ENERGY TRANSITION REALITIES

Table of Contents

We are making a terrible mistake when it comes to future energy policies. In previous letters, we have touched upon the challenges of the so-called "energy transition." Today, we will explain in detail the imminent harm awaiting investors and policy makers who fail to acknowledge certain realities. Every green energy proposal we have examined relies on the trifecta of wind, solar, and electric vehicles combined with various battery technologies. In recent months, a renewed "hydrogen mania" has broken out as well, which adds a fourth leg to the green energy stool. Unfortunately, based upon our extensive research, these plans, including the current hydrogen craze, are bound to at best severely disappoint and, at worst, outright fail in what they attempt to accomplish.

Not only will these proposals cost trillions, but policy experts and investors will soon realize that none of these options will address the very CO2 problem they are designed to solve. Currently, there are 410 parts per million of CO2 in the atmosphere. By keeping the concentration below 450 ppm, it is widely believed warming trends can be curbed. This would require lowering annual CO2 emission nearly 60% from 34 billion tonnes today to 15 billion tonnes by 2040. Most energy transition plans advocate the widespread adoption of renewable energy and electric vehicles to drive down carbon emissions. Unfortunately,

GOEHRING & ROZENCWAJG
Natural Resource Investors

"NONE OF THESE OPTIONS WILL ADDRESS THE VERY CO2 PROBLEM THEY ARE DESIGNED TO SOLVE."

our research suggests these plans have little hope in solving the CO2 problem.

Vaclav Smil, Distinguished Professor Emeritus in the Faculty of Environment at the University of Manitoba, is the best energy scholar we have ever read, in our opinion. In his *Energy Transitions*, he notes that historically a new energy source takes between 40–60 years to gain significant market share. The current proposals assume wind and solar will make comparable gains in only 20 years. Ambitious plans often carry ambitious budgets, and the green energy transition is no exception. Using extremely aggressive cost saving assumptions, a widespread move to renewable power is expected to cost $70 tr over 20 years, nearly $50 tr more than if we stayed on the current trajectory. Unfortunately, our research tells us this additional spending will not even come close to generating the expected reduction in global carbon.

The sums involved are monumental, and much of it could fall into the category of "malinvestment" with disastrous results. The further down the current path we go, the less likely we will be able to change course later. A decade ago, a series of failed promises and bankruptcies plagued the battery industry, making it nearly impossible for subsequent ventures to find financing and move forward. We worry the same could occur on a much larger scale if tens of trillions of "green" investments are eventually written off.

This essay will serve as a jumping off point outlining our research on various energy transition topics. We intend to follow this up with a series of essays, podcasts, and videos going into greater detail on each topic we introduce here. Please visit our website (gorozen.com) for ongoing updates.

This discussion comes at a critical moment. Over the last 12 months, green energy momentum has exploded. Investor euphoria has now reached new heights bordering on mania. Renewable investments (as measured by the RENIXX, ICLN and QCLN ETFs) have advanced between two and three-fold since the start of 2020. Tesla is up ten-fold and sports a market capitalization of $800 bn. Hydrogen stocks have done even better: Plug Power is up 2000% since January 2020 resulting in a market capitalization of $31 bn (or 100 times revenue). Investors have taken notice and poured huge sums of capital into green ETFs. Shares outstanding of the four most prominent clean energy ETFs are all up between three-and six-fold. Traditional energy has been on the other side of this trade. Over the same period, shares outstanding of the XOP ETF (designed to track S&P exploration and production stocks) are down 25%.

"STRETCHED VALUATIONS LEAVE INVESTORS VULNERABLE TO ANY SETBACK OR DELAY IN THE GREEN ENERGY TRANSITION."

Stretched valuations leave investors vulnerable to any setback or delay in the green energy transition. The ICLN ETF holdings currently trade at 70x earnings, 6x sales and 6.25x book value, suggesting dramatic growth is already priced in. What would happen if the energy transition proved more challenging than anticipated?

Green energy Special Purpose Acquisition Vehicles (SPACs) are also a troubling sign. Green SPACs have raised $40 bn in 2020 alone with a mandate to acquire as-of-yet unidentified clean energy assets. Oil and gas exploration and production companies on the other hand raised only $5.2 bn in 2020 to develop their existing proven asset bases. Given how challenging clean energy product development can be, we fear the bulk of these green SPACs will likely end up being written off entirely.

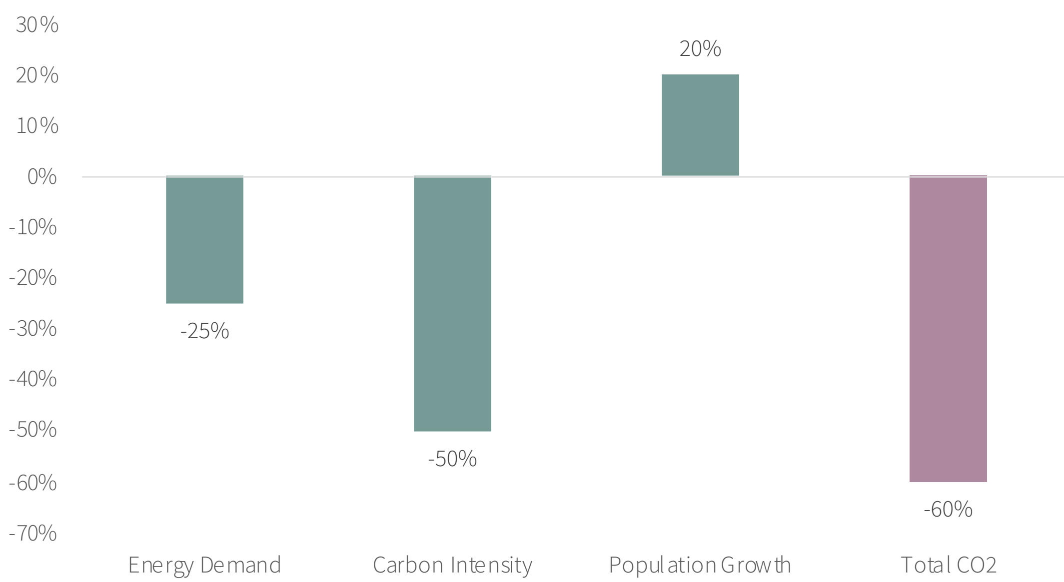
Adding to the current green momentum, several reputable agencies released reports in 2020 predicting an acceleration in renewable adoption. The International Energy Agency (IEA)

"STOCK PERFORMANCE AND NEWS ARTICLES HAS CREATED A DRAMATIC FEEDBACK LOOP"

released its World Energy Outlook in October 2020. In their report, they lay out a "Sustainable Development Scenario" in which global oil demand peaked in 2019 and will fall by 34% by 2040. Countless news articles picked up on the "peak demand" prediction and pointed to the strength in renewable equities as "proof" the era of hydrocarbons is now ending. The combination of stock performance and news articles has created a dramatic feedback loop, pushing prices up even further and in turn giving more credibility to the energy transition thesis.

The IEA's World Energy Outlook generated a lot of attention when it was released. Upon closer inspection, we believe the report makes two critical mistakes. While CO_2 emissions fall to 15 bn tonnes by 2040, the drivers of the reduction seem questionable. For emissions to fall 60% over the next twenty years, the IEA assumes per capita energy demand will fall by 25% while CO_2 per unit of energy drops by 50%, offset by population growth of 20%. Together, these factors equate to a 60% reduction in total carbon emissions and keep atmospheric CO_2 to within 450 ppm. Unfortunately, neither energy intensity nor carbon intensity are likely to fall anywhere near the amount predicted by the IEA.

FIGURE 1 Drivers of Lower Emissions, 2019–2040



Source: IEA.

"MOST CLIMATE PROPOSALS ARE BASED ON CONSUMING 25% LESS ENERGY."

Few people are aware that most climate proposals are based on consuming 25% less energy. According to the BP statistical review, there has not been a single 20-year period since their data begins in 1965 where per capita demand has fallen by more than 0.1%, making this assumption untenable.

While our research suggests today's green energy mania will not reduce carbon emissions (and curtail global warming) as expected, we believe there is a more straightforward, feasible solution. Nuclear power is the only technology that can provide reliable carbon-free baseload power. Any proposal seeking to seriously address carbon emissions must heavily incorporate nuclear electricity generation. Unfortunately, none of the current proposals include a material nuclear contribution. There is some reason to be optimistic however: the Biden administration has acknowledged the need for nuclear power in combating climate change and may signal an important impending change in policy outlook.

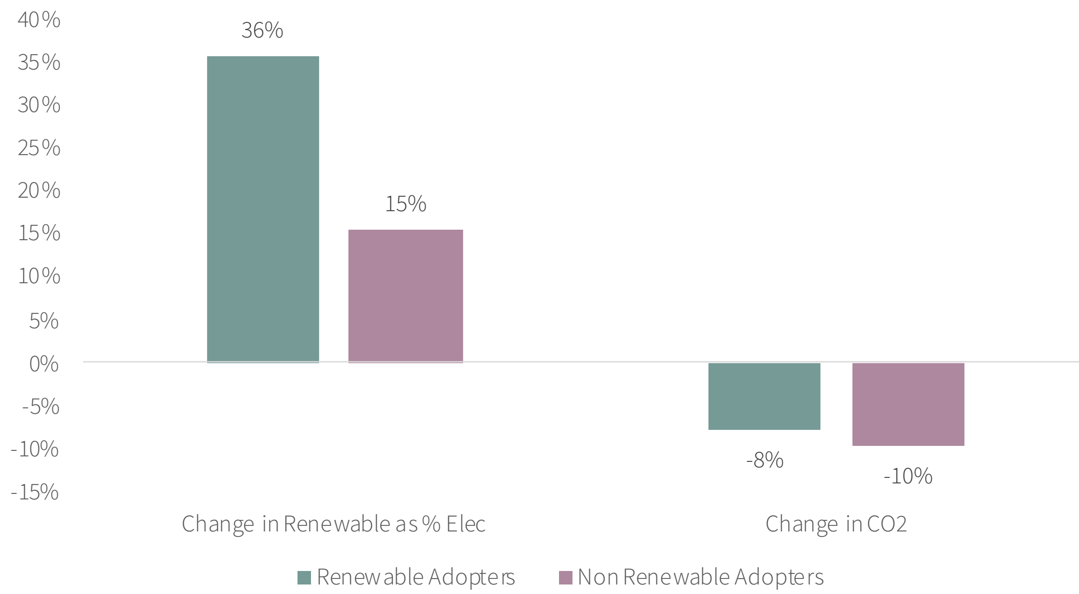
We have invested in the global natural resource industry for 30 years. At present, approximately half our investments are in oil and gas related equities with another 15% in uranium producers. While some may argue this makes us biased, we disagree. Nothing in our investment mandate requires we be invested in any particular natural resource subsector. If our research pointed to the end of the hydrocarbon era, we would turn our attention to other areas such as battery metals and renewable energy. Instead, we continue to see a future for hydrocarbons, particularly as a transportation fuel. While carbon emissions should be addressed, wind, solar, hydrogen fuel cells and battery powered electric vehicles are not the solution. Our investments are consistent with our research and not the other way around.

We have spent years studying energy trends in emerging markets. Over that time, non-OECD countries have gone from consuming 40% of all primary energy to 60%. As an emerging market gets richer, it reaches a tipping point and starts to consume more energy. Once an economy is developed, it reaches a saturation point and energy demand moderates. Since 2000, non-OECD countries have grown their primary energy demand per capita by 65% compared with a reduction of 10% in the OECD world. Even following two decades of strong growth, non-OECD demand is still 70% below OECD levels suggesting more growth is yet to come. Non-OECD real GDP per capita is expected to double over the next 20 years, suggesting these trends will continue. Instead, the IEA projects emerging market per capita energy demand will fall by 20%. Simply put, this is impossible. Over the last two decades, real GDP doubled, and energy demand rose 60%. Even if this relationship is cut in half, the next doubling on GDP would result in energy demand growing by 30% by 2040, not falling by 20%.

OECD per capita demand is projected to fall by 30% or three times the rate of the last two decades. While there is more “discretionary” energy demand in affluent countries, a 30% drop would take per capita energy use to 1955 levels—something we do not believe is likely. If OECD per capita demand falls by 10% instead of 30% and non-OECD demand grows by 30% instead of falling by 20%, per capita primary energy will grow by 12% instead of falling by 25%, leaving total demand 50% higher than the IEA expects.

Unfortunately, carbon intensity per unit of energy consumed is unlikely to fall by the 50% assumed in the IEA’s proposal either. It is widely believed the reduction will be based upon the widespread adoption of wind, solar, electric vehicles, and hydrogen fuel cells, but our research suggests these technologies will fail to deliver the expected results. There are several real-world examples that confirm our suspicions. Over the past two decades, Germany has aggressively pursued its renewable-centric “Energiewende” plan, taking renewables from 2% of all German electricity to nearly 40%—by far the most aggressive renewable push in the world. Over the same period, carbon emissions per unit of energy fell by only 12%. Not only is this reduction a far cry from the projected 50% reduction in most energy transition plans, but it is also no better than those countries that did not adopt a renewable energy push. Between 2000 and 2019, the US and France went from 1% renewable electricity to 10%, or less than one-third of Germany’s penetration. Despite this lack of renewable adoption, US carbon intensity fell by 13% while France’s intensity fell by 10%, ahead of and only slightly behind Germany, respectively.

FIGURE 2 Renewables & Carbon, 2000–2019



Source: BP. Renewable adopters include Denmark, Lithuania, Germany, United Kingdom, Ireland, Luxembourg, Portugal, Estonia, Spain, Chile. Non Renewable countries include US, Canada, Ecuador, Czech Republic, Finland, France, Hungary, Poland, Romania, Slovenia, Turkey, Ukraine, Russian Federation, Turkmenistan, Uzbekistan, Israel, Egypt, Malaysia, South Korea, Taiwan, Thailand.

Electric vehicles will likely not deliver the necessary carbon reduction either. In Norway, electric vehicle sales have gone from zero to nearly 60% penetration between 2010 and 2019. Despite such a dramatic shift away from oil, Norway's carbon intensity has declined by 10% compared with 11% in the US where EVs remain less than 2% of all vehicle sales.

Although these results might seem improbable, the explanation has to do with the physical limitations of the various technologies.

Wind and solar are extremely inefficient generators of electricity due to their low energy density and their intermittency. In the coming weeks, we will release a podcast that goes into much greater detail about these shortcomings. In summary, a solar panel likely only dispatches between 12 and 20% of its rated capacity due to the intermittency of sunshine. A wind turbine is somewhat better, but still less than 25%. As a result, excess capacity must be built to generate the necessary electricity. Moreover, the power must be "buffered" by a storage system to smooth out the inherent variability coming from both short-term dislocations (clouds and periods of calm), as well as different patterns between day and night.

Low load factors and "buffering" of intermittency results in poor "energy return on energy invested" (EROEI). As much as 25–60% of the energy generated in a renewable system is consumed internally, compared with 3% for a modern gas plant.

"ACCORDING TO OUR MODELS, WIND AND SOLAR WOULD MARK THE FIRST TIME WE HAVE SEEN A WIDESPREAD SHIFT INTO A MUCH LESS EFFICIENT SOURCE OF ENERGY CONVERSION."

In his excellent work, Energy and Civilization, Professor Smil describes society's ongoing adoption of new technologies. A theme that runs through his work is how every new major "prime mover" is able to convert energy into useful work more efficiently than what came before. According to our models, wind and solar would mark the first time we have seen a widespread shift into a much less efficient source of energy conversion. It has never happened in the past, and the only way it can happen in the future is if governments subsidize wind and solar (as is being done right now), or outlaw old hydrocarbon-based technologies—now being threatened. In either case (subsidy or outlaw), government intervention is the only way people would likely adopt new energy conversion technologies with inferior efficiencies.

"TO THE EXTENT OVERBUILDING AND BATTERY BACKUP IS REQUIRED TO ALLOW FOR BASELOAD POWER, CO2 EMISSIONS INCREASE DRAMATICALLY."

It is difficult to forecast the impact of transitioning from a system where 3% of all energy is consumed internally to one where more than a third is lost. To the extent solar and wind facilities do not achieve their target lifespans (and there is ample evidence to suggest this is happening), the results will be even worse.

Solar and wind's low EROEI also impacts their carbon emissions. While billed as being "carbon free," solar and wind generate CO2 during their construction and maintenance. To the extent overbuilding and battery backup is required to allow for baseload power, CO2 emissions increase dramatically. This partially explains why German carbon intensity only fell by 12%, despite having among the highest renewable penetration in the world.

Electric vehicles also involve energy intensive lithium-ion batteries. Few realize how much energy is embedded in an electric vehicle before it is ever plugged in. Over the life of a typical EV, nearly 40% of the total energy goes into manufacturing the battery. The IEA expects electric vehicles will represent nearly 15% of total transportation energy by 2040. We calculate this equates to approximately 850 mm EVs and nearly 65 terawatt hours of batteries. This is a staggering amount considering global lithium-ion manufacturing capacity is currently less than 0.4 terawatt hours per year. These batteries will require an incredible 2 billion tonnes of oil equivalent to build.

We will shortly release a detailed podcast that goes into these figures in great depth. Unfortunately, few people realize how energy intensive the "green transition" will be. As a result, much (if not all) of the carbon savings will be undone by generating the power in the first place. The IEA's proposal assumes wind and solar make up nearly 50% of all electricity by 2040 and that some 850 mm electric vehicles will be on the road. These initiatives are expected to reduce CO2 by 55% or 18 bn tonnes per year. While this may sound impressive, simply moving away from coal towards much-cleaner natural gas would itself save nearly 14 bn tonnes of CO2 per year. When analyzed through this perspective, renewables would save an incremental 4 bn tonnes compared with the next cleanest option.

At the same time, an incredible amount of energy is required to build out the renewable capacity and manufacture the necessary batteries. A move toward gas would be much more energy efficient (given its high EROEI) and would not require batteries for either grid storage or automotive uses. We estimate the move toward renewables and EVs would generate nearly 45 billion tonnes of incremental CO2. Therefore, nearly 10 years of carbon "savings" would be spent on the energy transition itself. A battery is expected to last between 6 and 15 years depending on charging behavior while wind turbines have an expected life of 20 years and PV solar panels have a useful life of 25 years. At best, a huge amount of the expected carbon savings will be undone by the necessary manufacturing. At worst, the impact could be net detrimental.

Early wind turbines are failing at much higher rates than expected, suggesting a 20-year useful life may be too long. Similarly, PV solar facilities are noticing higher performance degradation than expected in their facilities. We will discuss both topics in depth in an upcoming podcast. Given the huge upfront energy needs of wind, solar and batteries, any performance disappointment could mean the difference between moderate carbon savings and net increases in carbon. We believe this partly explains why total carbon intensity has not fallen as much as expected in countries with large renewable mandates. Countries that have adopted natural gas, on the other hand, have seen better results while spending trillions less. Moving towards nuclear generated electricity is an even better option and would allow for the greatest carbon reduction while still saving trillions. We will explore this option at the end of this essay.

Clearly a major part of the problem is the energy-intensive lithium-ion battery used in EVs and for grid-level renewable storage. To address this issue, hydrogen fuel cell technology is once again being put forward as a possible solution. This marks the second investment mania in hydrogen fuel cells in 30 years. In the late 1990s, fuel cells went through an impressive bull market that saw Ballard rise 1400% over three years before crashing 99%. Even after its recent 600% advance it is still 70% below its prior peak. Unfortunately, many of the technical issues that led to the previous hydrogen bust remain.

We will dedicate an upcoming podcast to hydrogen. In the meantime, it is important to realize that while the fuel cell does not need an energy-intensive battery, it is nevertheless an extremely inefficient technology. To make hydrogen, electricity is used to electrolyze water resulting in oxygen and hydrogen gas. The gas is then compressed or liquefied for transport to the end user. In the fuel cell, hydrogen is reformed back into water producing an electrical current used to power a motor. Not having to manufacture an energy-intensive battery saves on upfront energy dramatically.

Unfortunately, any savings are "spent" on the extremely poor overall energy efficiency of the system. Powering an electrolyzer to produce hydrogen gas loses upwards of 30% of the embedded energy. Compressing or liquefying the gas for transportation loses another 15% of the energy. Generating an electric current in the fuel cell loses yet another 30% of the contained energy. In total, we estimate that 70% of the electricity used to power the system is wasted. Even though there is no energy-intensive battery to manufacture, we believe hydrogen fuel cells requires more total energy to power a car than standard EVs despite their lithium-ion battery. When wind or solar is used to manufacture the hydrogen (i.e., "green" hydrogen), the overall energy efficiency become even worse. To achieve a reduction in net emissions requires the original electricity be nearly four times less carbon intensive to make up for the 70% energy lost in the system. Solar and wind powered "green hydrogen" vehicles would not generate any net carbon savings compared with gasoline or diesel and would likely be much worse.

As we discussed, moving away from coal toward natural gas would be a great first step in reducing carbon. We believe there is an even better solution that would reduce emissions much further. Any serious proposal to reduce the carbon intensity of energy needs to have several characteristics: it must be very energy efficient as measured by EROEI; it must be able to supply baseload power and avoid intermittency; it must be scalable to meet ongoing global energy demand growth; and it must be low-carbon or carbon-free. The only source that meets these criteria is nuclear fission.

A modern reactor generates electricity with an EROEI of nearly 100 compared with 30 for gas and 1–4 for renewable. As a result, only 1% of the generate electricity is consumed internally compared with 3% for gas and 25–60% for renewable energy.

If per capita energy demand rises by 12% (instead of falling by 25%), carbon intensity would need to fall by two-thirds to keep total emissions to within 15 tonnes and limit atmospheric

CO2 to within 450 ppm. Only a combination of nuclear energy and efficient natural gas can hope to get close.

In future podcasts, we will outline a possible energy plan that would use nuclear and gas to dramatically reduce CO2 intensity while retaining oil as a key transportation fuel. Crude is extremely energy dense per kilogram, making it invaluable in powering things like cars, trucks, and planes.

"ACCORDING TO OUR MODELS, AN AGGRESSIVE PUSH TOWARD NUCLEAR AND GAS WOULD ALLOW TOTAL GLOBAL ENERGY DEMAND TO GROW BY 35% OVER THE NEXT TWO DECADES (INSTEAD OF FALLING PER THE IEA) WHILE STILL CUTTING CARBON EMISSIONS BY NEARLY HALF."

According to our models, an aggressive push toward nuclear and gas would allow total global energy demand to grow by 35% over the next two decades (instead of falling per the IEA) while still cutting carbon emissions by nearly half.

Such a plan would save nearly $30 trillion, some of which could then be used to pursue the more promising carbon-mitigation technologies. While still in the early stages, there are some very exciting companies advancing various new solutions. Boston Metal and Ambri were both founded by Professor Donald Sadoway, John F. Elliott Professor of Materials Chemistry at the Massachusetts Institute of Technology (and presenter at the 2018 Goehring & Rozencwajg Investor Day). Boston Metal is exploring ways to produce carbon-free steel (8% of global emissions) and has just secured a $50 mm investment from mining giant BHP. Ambri is developing a liquid metal battery better suited for grid level storage that shows early promise. Another area that shows promise is cement manufacturing. CarbonCure injects CO2 into the cement stream to strengthen concrete. The process has two benefits. First, the captured and injected CO2 is not released into the atmosphere. Second, cement per tonne of concrete is reduced by 5%. Cement manufacturing represents 8% of all carbon emissions and so any reduction would be meaningful. Many of these technologies are early stage and their eventual success is far from uncertain. However, our research tells us that taken collectively these technologies are much more intriguing than the current portfolio of wind, solar, EVs, and fuel cells that we expect will continue to disappoint.

"WE ARE EXTREMELY IMPRESSED BY THE WORK BEING DONE AT BREAKTHROUGH ENERGY VENTURES. FOUNDED BY BILL GATES, BEV SEEMS TO UNDERSTAND THE NUANCES OF THE ENERGY TRANSITION."

There are signs that perhaps investors and policy makers are beginning to appreciate the limitations of the current "green" transition. The Biden administration has taken the most favorable view on nuclear power in decades. Delaying nuclear closures (currently rumored) would be a huge step in the right direction. On the investment side, we are extremely impressed by the work being done at Breakthrough Energy Ventures. Founded by Bill Gates, BEV seems to understand the nuances of the energy transition. It is no surprise that BEV is heavily invested in nuclear power along with several of the technologies we discuss above.

Please continue to check back for ongoing installments in this series on our website going forward. It is a fascinating topic, and we are excited to share our research with you.

Q4 2020 Natural Resource Market Commentary

Commodities and natural resource related equities continued to advance inQ4. Pfizer's announcement regarding the successful trial of their COVID-19 vaccine, followed several weeks later by a similar announcement from drug maker Moderna, reinforced investors' beliefs that economic activity in 2021 will normalize and that strong economic growth will resume.

Economically sensitive commodities showed particular strength. Oil advanced over 20%. Base metals advanced between 14% and 16%, with copper again being the best performing metal. Agricultural prices were strong with both corn and soybeans up over 25%. Silver, given its greater economic sensitivity, was up 12% during the quarter. Gold, given its "safe haven" status during the worst of the COVID-19 related market turmoil, was flat. Broad based commodities, as measured by the Goldman Sachs Commodity Index rose 20%.

Natural resource stocks were particularly strong during the quarter. Exploration and production stocks (as measured the XOP ETF) surged 40%, oil service stocks (as measured by the OIH ETF) surged almost 60%, base metal stocks (as measured by the XBM ETF) rose 37%, and copper related equities (as measured by the COPX ETF) surged by almost 50%. Both the S&P North American Natural Resource stock index (an index heavily weighted towards North American energy stocks) and the S&P Global Natural Resource Index (more heavily weighted toward mining and agricultural stocks) advanced 19% and 21%, respectively. The stock market was also strong, once again driven by the large capitalization technology stocks. The S&P 500 Index rose 12%.

For all of 2020, commodities and their related equities were mixed. Energy was generally weak while metals and agriculture were strong. Oil prices fell 22% in an incredibly volatile year that saw WTI oil prices trade as low as -$40 per barrel. Even with their surge in Q4, energy related equites were weak for the year. Exploration and production stocks (XOP ETF) fell 35%, oil service stocks (OIH ETF) fell 40%, and even integrated, pipeline, and refining stocks (XLE ETF) fell 30%. North American natural gas markets were the only bright spot in energy. Henry Hub natural gas prices rose 15% for the year. Copper led the base metals complex, rising 25%. In comparison, zinc, nickel, and aluminum rose 22%, 17%, and 10% respectively in 2020. Copper equites (COPX ETF) led the metal related equites, rising a strong 50% for the year. On average, base metal stocks (XBM EFT) rose 30%.

The precious metals complex again showed considerable strength for all of 2020. Given its economic sensitivity and strong second half performance, silver led the precious metals. Rising almost 50%, silver outperformed gold (+25%), palladium (+20%) and platinum (+10%). Silver related equites (SIL EFT) were also strong performers for the year and bested gold stocks as measured by the GDX EFT (+45% versus +25%).

Grain prices showed considerable strength throughout 2020. Soybeans rose almost 40%, corn rose 17%, and wheat rose 15%.

Energy Markets in Q4

The oil market tightened significantly in Q4 as global oil inventories continued to decline. According to the Energy Information Agency (EIA), US inventories fell 84 mm barrels during the quarter, 49 mm barrels more than the seasonally adjusted ten-year average. On a global basis, the International Energy Agency (IEA) reported oil and product inventories fell by 125 mm barrels between August and November (most recent data), or 81 mm barrels more than the seasonal average. As we outlined in our last letter, both US and non-OPEC+/non-US oil production continues to slip. Most energy analysts believed US production would rebound in Q4 once shut-in wells from the second quarter were brought back online. Also, a significant number of drilled but uncompleted wells (DUCS) were expected to be completed in the second half of 2020, also causing US oil production to grow.

Neither the return of shut-in production nor the acceleration of DUC completions has stemmed the production decline. As of November (the latest data point available), the EIA reports US total oil production has declined by over 1.7 mm barrel per day year-over-year. Furthermore, the EIA's Drilling Productivity Report predicts shale production will fall another 250,000 b/d between November and February.

Why hasn't US production rebounded, as predicted by most energy analysts including the IEA? In the Oil Section we will discuss the underlying factors and why 2021 will likely be another year of shale disappointment and decline.

Regarding demand, we believe 2021 will see a huge rebound. Although the financial press has made little comment, oil consumption in China, India, and now Brazil has made new highs. If our models of emerging market oil demand are correct, 2021 will see global oil demand surpass its pre-COVID highs as the successful roll-out of vaccines gets underway.

As we progress through the year, we expect a structural gap between supply and demand will emerge, eventually approaching nearly three million barrels per day, even once all OPEC+ curtailed oil is brought back onto the market. Given that oil prices should recover strongly in 2021 and that oil-related investments remain undervalued, we recommend maximum exposure in this space.

Natural gas prices were flat in Q4. As we wrote last quarter, the forecasted rebound in US natural gas production has not taken place. Almost all gas wells that were shut-in back in April and May are now once again producing. However, EIA data indicates US production remains almost 5 bcf / day (or 8%) lower, year-over-year. Base production declines have overwhelmed the return of shut-in gas, a subject we covered at length in previous letters. Given today's drilling activity, we believe steep production declines will continue into 2021. The EIA's drilling productivity report expects US shale gas production will decline an additional 1.4 bcf /day between November and February. Although the US gas rig count has rebounded by 25 rigs in the last several months, today's rig count (88 rigs compared with 200 as recently as mid-2019) remains far too low to hold gas production flat.

"THE ONLY THING KEEPING NATURAL GAS PRICES FROM SURGING HAS BEEN AN EXTREMELY WARM FALL AND START TO THE 2020-2021 WINTER."

The only thing keeping natural gas prices from surging has been an extremely warm fall and start to the 2020–2021 winter. Both November, December and the first two weeks of January were 10% warmer than normal. The warm weather has reduced heating demand leaving US natural gas inventories approximately 10% higher than the five-year seasonal average. Weather models indicate that much colder weather will likely grip the North American continent in February.

While North America has been warmer than normal, Europe and Asia have both been much colder causing both natural gas demand and spot LNG import prices to soar. Both European and Asian spot LNG prices spiked into the mid $20's and low $30's per mmbtu, respectively in early January—both records. Concerns over global LNG deficits in the coming years have now emerged. Demand for US LNG exports reached an all-time high of nearly 10 bcf/d in December after having collapsed to only 3 bcf/d in July.

"DEMAND FOR LNG WILL OUTSTRIP SUPPLY AS WE PROGRESS THROUGH THE DECADE."

Seven years ago, we wrote extensively about global natural gas demand, and how emerging market demand would far outstrip the growth in future LNG supply. In the natural gas section of this letter, we have updated our 2014 LNG models. We continue to believe demand for LNG will outstrip supply as we progress through the decade. Tight LNG markets means strong demand for US exports as global consumers constantly attempt to lock in longer-term supply.

We remain extremely bullish on North American natural gas and recommend significant exposure to high quality E&P companies.

Agricultural Market in Q4

Agricultural markets showed pronounced strength in Q4 and grain prices continued to advance into January. Corn and soybean prices rose an additional 15%, and 4 % since January 1 respectively. World Agricultural Supply and Demand Estimates (WASDE) reports put out in November, December, and January by the USDA, were behind the strength.

In their November WASDE report, the USDA unexpectedly made a sharp downward revision in corn crop yield assumptions. In December, they significantly boosted export demand for soybeans. In January, they again significantly reduced their 2020 crop yield estimate for both corn and soybeans. After incorporating these changes, the January WASDE report reduced the size of the 2020–2021 ending corn stock estimate from 1.7 bn bushels to 1.55 billion bushels. Although not yet at critical levels, the present corn carryout estimate could easily fall into dangerous territory if the 2021 northern hemisphere suffers any adverse weather condition.

Regarding soybeans, the January WASDE report also lowered the 2020 US soybean yield estimate from 50.7 bushels per acres to 50.2, resulting in another reduction in ending stock estimates for 2020–2021. Soybean ending stocks are now expected to reach critically low levels of 140 mm bushels. Extremely strong global grain demand is now expected to collide with low ending inventory levels given any potential weather-related supply disruptions. The stage is set for a huge bull market in global agriculture, and we recommend investors have significant exposure to agricultural related equities, primarily fertilizer producers. The agricultural section of this letter offers a detailed discussion of current supply and demand trends, including a discussion of the huge reductions to both corn and soybean carryout estimates. That section also has an update of the 25th sunspot cycle which has now started. Long term changes in weather patterns may already be affecting today's global weather conditions

Copper Markets in Q4

"COPPER CONTINUES TO BE OUR FAVORITE BASE METAL."

Base metals prices were strong in Q4 with copper again leading—rising over 16%. Since base metals bottomed in Q1 of 2016, copper is the only metal to have made a new high for this cycle. Copper equities in January made a significant new post-2016 cycle high as well, confirming the new high in the metal price. Copper continues to be our favorite base metal.

The underlying fundamentals in the global copper market remain extremely bullish. Chinese copper demand surged in 2020, more than making up for the significant COVID-19 related pullback in the rest of the world. According to the World Bureau of Metal Statistics (WBMS), Chinese copper consumption surged 17% year-over-year for the first 11 months of 2020. Outside of China, copper consumption in the rest of the world fell by 7%. In aggregate, total world consumption rose by 5.5%, according to WBMS statistics. Although the surge in Chinese copper consumption might seem unsustainable, Chinese copper consumption has closely followed what our models first predicted several years ago. In previous letters, we outlined how various levels of emerging market GDP must be supported by specific levels of copper investment. For example, China has approximately 185 lbs of copper installed per capita, exactly the level needed to support China's GDP of $17,000 per capita. For China to avoid getting stuck in the "middle income" trap, it must continue to make significant copper investments in its economy. To achieve real per capita GDP of $24,000, China must increase its copper investment to 300 pounds per capita. Assuming this takes place over the next six-year, Chinese copper consumption must grow by over 800,000 tonnes per year.

China today is pushing to become a leader in generating electricity from renewable sources, an extremely copper intensive exercise. This alone could add several hundred thousand tonnes of incremental copper consumption annually. Also, China, has announced huge investments in their data center and cloud computing industries, both extremely copper and power intensive.

Given the rollout of the various COVID-19 vaccines, we expect a significant global economic recovery will take place this year. Even if Chinese copper demand shows no growth in 2021, copper demand outside of China should return to pre-COVID levels, adding over 700,000 tonnes of year-over-year growth, or about 3%.

"A STRUCTURAL DEFICIT HAS CREPT INTO GLOBAL COPPER MARKETS THAT WILL BECOME INCREASINGLY OBVIOUS TO INVESTORS AS THE DECADE PROGRESSES."

A structural deficit has crept into global copper markets that will become increasingly obvious to investors as the decade progresses. Strong demand, driven by emerging markets and the expressed desire to make significant investments in renewable electricity investments, is now upon us. Confronting this strong demand is copper mine supply that will show little in the way of growth. Few large copper mining projects are slated to come online over the next five years. Cobre Panama, the large copper project in Panama, started production in 2019 and will provide an additional 100,000 tonnes of copper supply in 2021. The other large copper project slated for 2021, the 400,000 tonne per year Oyu Tolgoi underground expansion, has been delayed until Q4 of 2022. Rio Tinto, the mine's operator, has hinted that continued technical issues might delay the start of the "undercutting" process—the first step in the block caving process. If this happens, first production from the Oyu Tolgoi underground mine would be pushed back to 2023. The only other large-scale copper mine scheduled to come online over the next several years is the massive Kamoa-Kakula mine in the Democratic Republic of Congo (DRC). Production is scheduled to start in Q3 of 2021 and ramp up into 2022. Expected copper production in 2022 could reach 200,000 tonnes which would be expanded to 400,000 in 2024.

The lack of massive new copper mining projects, coupled with an ever-accelerating copper mine depletion problem, means growth in mine supply should remain minimal over the next five years. Global copper consumption exceeds copper mine supply and recovered copper scrap by about 500,000 tonnes per year presently and will get worse. Global inventories are experiencing sharp declines suggesting a structural deficit has now emerged. Warehouse inventories at the three big metal exchanges (the Shanghai, COMEX, and LME) peaked out at approximately 650,000 tonnes back at the end of March 2020 before falling by 400,000 tonnes to reach only 250,000 tonnes today.

We believe copper prices are headed much higher and continue to recommend maintaining exposure to copper related investments.

Precious Metals in Q4

Gold prices during Q4 traded sideways while silver, given its greater economic sensitivity, advanced 7%. Gold stocks (as measured by the GDX ETF), which had been almost as strong as tech stocks in the first three quarters of 2020, pulled back 7%. As we wrote in the precious metals section in last quarter's letter, we believe the huge catch-up surge in silver prices, which took place between May and August last year, signaled that the precious metals complex would enter into a period of price consolidation. Since gold prices peaked at $2,060 per ounce back in August 2020, both gold and silver prices have traded sideways to slightly down. Today's gold market is under the influence of two opposing factors. First, on the positive side, it now looks like Chinese gold buying has returned. In last quarter's letter, we wrote about the mysterious weakness being exhibited by Chinese gold buyers. Reflecting the strength in Chinese physical gold demand, Shanghai gold prices have consistently traded at premiums (as high as $10 per ounce) to the world gold price over the last seven to eight years. However, starting in February 2020, Shanghai gold prices began exhibiting huge discounts to the world gold prices—discounts that reached almost $80 per ounce back in August. Although few commented on the potential causes for these huge discounts, we suggested high gold prices, combined with COVID-19 related dislocations, were the reasons. Whatever the underlying cause, the World Gold Council (WGC) has confirmed the weakness in Chinese demand. According to the WGC, Chinese gold demand fell 60% during Q1 2020 (most likely due to COVID-19 related dislocations). Although the next quarter showed a large rebound, the WGC figures show Chinese retail gold demand in Q3 was still 13% below year-over-year levels. Demand losses of this magnitude would explain the extremely large Shanghai price discounts experienced over the last 10 months. However, starting at the end of December, Shanghai gold premiums began contracting and, by the second week of January, the Shanghai gold price returned to premiums for the first time in 10 months. Although we may never know what caused the extreme weakness in Chinese gold demand in 2020, it now looks as though Chinese gold demand has returned.

India never exhibited the same persistent weakness as China. After a brief period back in April and May, duty-adjusted gold premiums in India have remained robust over the last six months and have strengthened even further since the start of 2021. The return of Chinese demand, along with continued robust Indian demand are both big positives for the gold price, and strongly suggests the corrective phase we have just experienced is unlikely to include many future sharp drawdowns.

Balancing out these positives, are two potential negatives. For the first time in two years, Western physical buying has weakened. After accumulating 230 tonnes in Q1, 385 tonnes in Q2, and 240 tonnes in the first two months of Q3, the 17 physical gold ETFs we track stopped buying gold at the beginning of Q4. In December, they actually shed small amounts of physical metal. For Q4 as a whole, these ETFs shed 120 tonnes. The nine physical silver ETFs showed similar investor behavior: after accumulating 1,300 tonnes of silver in Q1, 4,150 tonnes in Q2, 2,730 tonnes in Q3, and 1,000 tonnes in the beginning of November, they abruptly stopped buying metal.

"WE CONTINUE TO BELIEVE THIS GOLD BULL MARKET WILL BE DRIVEN BY WESTERN INVESTORS, AS OPPOSED TO THE 1999-2011 GOLD BULL MARKET, WHICH WAS DRIVEN ALMOST ENTIRELY BY INVESTORS FROM INDIA AND CHINA."

We continue to believe this gold bull market will be driven by Western investors, as opposed to the 1999–2011 gold bull market, which was driven almost entirely by investors from India and China. The recent slacking of Western demand, as measured by the physical ETFs we follow, gives us more evidence that a potential lengthy period of sideways price action in both gold and silver prices is now taking place.

The second negative data point is slowdown in central bank gold buying. According to the most recent WGC data, net central bank sales totaled a sizeable 12 tonnes in Q3. The last time we saw a quarter with net central bank gold sales occurred all the way back in Q4 2010, when central banks sold over 20 tonnes.

"THE LAST TIME WE SAW A QUARTER WITH NET CENTRAL BANK GOLD SALES OCCURRED ALL THE WAY BACK IN Q4 2010, WHEN CENTRAL BANKS SOLD OVER 20 TONNES."

After being one of the largest gold buyers over the past year, Turkey has now turned into a seller. Threatened with US-led sanctions, the country shifted its reserve assets out of the US dollar into gold. However, given Turkey's steadily worsening fiscal and monetary situation, we conjectured this source of central bank gold buying couldn't continue. After accumulating 170 tonnes in the first six months of 2020 (making it the largest central bank buyer), Turkey sold 22 tonnes in Q3. (Just released WGC data indicates that Turkey was also a sizeable gold seller in Q4, as well.)

Also of interest was Russia's central bank sale of 1.2 tonnes in Q3. Over the last five years, Russia has been the largest gold buyer, representing 40% of all central bank buying. However, in Q1, Russia announced the suspension of all gold buying. No reason was given, although low oil prices, COVID-19 related economic dislocations, and Ruble weakness were the most likely explanations. In last quarter's letter, we speculated Russia could potentially turn from a gold buyer into a seller, given low oil prices and economic problems. Selling may have started in Q3, something that has to be carefully monitored.

After selling gold aggressively between 1992 and 2008, central banks over the last 12 years have turned into large buyers. In 2018 and 2019 alone, central banks purchased 630 and 660 tonnes of gold, respectively. For the first three quarters of 2020, however, central banks only purchased 215 tonnes, far behind the torrid pace of the two previous years. Given the huge financial strain now being put on government finances as a result of the COVID-19 pandemic, we believe we could be in for a substantial period of weakness in central bank gold buying with many even turning into sellers over the next several years. Central bank buying has had a significant role in gold's 100% price appreciation over the last three years—yet this positive impact could now be receding.

We remain extremely bullish on precious metals investments over the long term. We still believe we will see a $15,000 gold price before this gold bull market is over. For patient investors with long-term horizons, we recommend aggressive accumulation of both gold and silver on any price weakness over the coming months.

However, we also believe the current near-term period of gold price consolidation is not yet over. More aggressive investors should know that we believe oil prices have now entered into a period where they will significantly outperform the gold prices. Twenty years ago, gold was radically undervalued relative to oil (because of central bank selling) and gold ultimately proved to be the much better long-term investments. Today, because of ESG and climate related issues, oil has become the "un-investible" asset class, much as gold was 20 years ago. Reflecting its "un-investible" status, oil has never been more undervalued relative to gold. For aggressive investors, we recommend swapping some gold related investment into oil related investments. For those interested in our thinking on the relationship between gold and oil prices and why we believe oil is set to significantly outperform gold, please refer back to our "The Gold-Oil Ratio Revisited: Part 3." In our Q3 2020 letter.

Uranium Markets in Q4

Both spot and term uranium prices were flat during Q4. For all of 2020, spot prices advanced 21% and term prices were up 8%. Uranium related stocks did much better, advancing over 40% during Q4 after having been flat for the first nine months of the year. Investors responded favorably to President Biden's election after his campaign prominently featured nuclear power in its plans to decarbonize the US.

On November 23rd, 2020, then President-elect Biden appointed John Kerry to the newly created cabinet-level position of Envoy for Climate. While Mr. Kerry was critical of nuclear power in the 1990s, more recently he has spoken out supporting its role in curbing carbon emissions (a view we agree with emphatically).

In the near-term, a pro-nuclear Administration could result in the postponed retirement of several US reactors due to come offline over the next few years. While such a policy shift would only result in a 1–2% direct increase in global demand, it would serve as strong endorsement for the role of nuclear in delivering carbon-free energy. The increased demand might encourage US utilities to cover future uncontracted fuel requirements leading to increased tightness as well.

Even without delayed US reactor retirements, uranium demand is scheduled to grow dramatically as new reactors (mainly in non-OECD countries) come online in the coming years. Over the past two decades new reactor retirements have exactly offset new startups, resulting in mostly flat demand. From now to 2040, we expect 290 new reactors will be commissioned. Even if none of the US retirements are postponed, total reactor shutdowns will only total 154, resulting in 135 new net reactors, or 30% of the current total, by 2040. At current prices, it does not make sense to sanction any new mine supply, leaving a massive deficit in the coming years.

Despite the bullish outlook (and the Q4 rally), 2020 in many ways, was a frustrating year for uranium investors. Spot prices were strong between January and May, rallying from $24 to $34 per pound before retracing half the advance to end the year at $30.20 per pound on much lower volumes. Term prices rallied from $32 to $36 per pound between December and January and have been stable since on extremely depressed contracted volumes. Concerns over COVID related demand forced many term fuel buyers to the sidelines. US utilities are only 2% uncovered in 2021, but this level jumps to 35% by 2025, suggesting fuel buyers are vulnerable to any rise in price. With the recent speculation of delayed US reactor retirements, we believe we may see fuel buyers finally reenter the term contract market sometime in 2021.

Turning to supply and demand, trends exhibited in 2020 continue to be very bullish. Since nuclear reactors represent baseload capacity—much more so than natural gas plants—and rely on multi-year fueling programs, global demand was less impacted by COVID-19 than other areas in global energy markets. We estimate that global demand was only off 1%—or 1.2-mm pounds. Mine supply on the other hand was greatly impacted by curtailed production at Kazatomprom and the suspension of operations at Cameco's flagship Cigar Lake due to COVID cases among employees. In total, global mine supply was down 20 mm pounds or 14%. After restarting in September, production at Cigar Lake was yet again suspended in December and remains shut as of today, implying continued tightness into the first months of 2021. Global uranium inventories likely drew in excess of 30 mm pounds in 2020 and we anticipate further draws this year as well.

All of this lines up for a bullish year in global uranium markets. The total market capitalization of the industry is extremely small and any shift in investor sentiment would likely result in material stock price rallies. Perhaps the new Administration will help provide the necessary sentiment boost to incentivize fuel buyers to finally cover uncommitted obligations. Uranium remains the only way towards a less carbon intensive baseload energy supply and we are encouraged that policy makers and investors are finally beginning to acknowledge this fact. We believe uranium stocks will be some of the best performing in the coming commodity bull market.

The Coming Global Agricultural Crisis

Over the last four years, global agriculture has sat on a knife's edge. Extremely strong grain demand, sourced from the developing world, has been met with extremely favorable global growing conditions resulting in bumper crops. Because of favorable weather, global grain markets have been able to accommodate strong demand with little in the way of upside price pressure. However, we believe this is now changing. A recent story in the January 2, 2021 edition of the Financial Times, which has garnered little in the way of investor interest, portrays global agricultural markets as already seeing the first signs of stress:

"FOOD PRICE RALLY STOKES FEARS OF SOCIAL UNREST.... PRESSURE MOUNTS ON POORER NATIONS AMID STOCKPILING, DRY WEATHER, AND SUPPLY PROBLEMS."

"Food price rally stokes fears of social unrest.... Pressure mounts on poorer nations amid stockpiling, dry weather, and supply problems."

Grain inventories have now been drawn down to levels that could easily slip into dangerous zones if weather in the 2021 northern hemispheric growing season becomes even slightly problematic, which we believe it may. The first signs of drought conditions have already emerged in Brazil, the wheat growing region of the Former Soviet Union, and in the US Midwest. Northeast China's wheat growing region is currently suffering extremely cold weather causing severe damage to their winter wheat crop.

As our readers know, we believe global weather patterns have changed. Although not commonly accepted, we believe we are now entering into a period of cooler weather, with far less stable, and more challenging growing conditions. For the last 40 years, global crop growing conditions have been extremely good—an almost unprecedented streak. Not every year in the last 40 has always been perfect, but we have not seen a stretch of adverse crop growing weather that has extended beyond one growing season. For example, extreme flooding in the Midwest took place in 1993 and 2019 and a severe drought gripped large portions of the Midwest in 2012. However, excellent growing conditions returned the following years.

You have to go back to the infamous "dust-bowl" decade of the 1930s to experience an extended period of challenging growing conditions that lasted for multiple seasons. The 40 years of extremely favorable global growing conditions have combined with improved seed genetics and better farm management techniques to enable the world to supply a global grain market that has seen demand ratchet up from 2% to 3% in the last 20 years. We believe this unprecedented stretch of excellent weather is about to change.

We see mounting evidence that sunspot activity in the 25th sunspot cycle (which has now begun) will be very weak. Although open to debate, we believe the surge in sunspot activity we have experienced over the last 60 years (the Modern Maximum) has helped produced our current warming cycle. The 25th sunspot cycle will be the third cycle exhibiting declining sunspot activity and could very well usher in a lengthy period of much cooler weather. Although climate followers don't like to admit this, one of the biggest beneficiaries of global warning has been global agriculture. The impacts of warmer weather are many, but the most significant is the lengthening of the northern hemisphere growing season over the last 50 years.

Although long-term weather predictions are difficult, the odds now favor significant disruptive weather occurring with greater regularity, including earlier frost in the fall and later frost in the spring. Also, this is going to be the first time that a declining sunspot cycle happens during a strengthening La Niña cycle. There are a number of weather followers who believe that the combination of these two cycles will result in extreme weather volatility over the next several years, again producing much more challenging grain growing conditions.

Tightening US Inventories

In our last letter, we warned that we were entering the annual period of relative quiet in grain markets with little expected in the way of news announcements. How wrong we were. Shortly after writing that, the USDA released their November WASDE report in which they unexpectedly reduced their 2020 US corn yield estimate by 2.6 bushels per acre. The USDA also raised estimated 2020–2021 US corn export demand by a large 325 mm bushels (up 15%). 2020–2021 ending stocks were also slashed 465 mm bushels from the October reports. The very bullish November WASDE report was followed by another extremely bullish report in January. The USDA again reduced corn yield assumptions by a further large 3.8 bushels per acre and reduced their 2020–2021 ending stock estimate by another 150 mm bushels. The January WASDE report marked eight months of nearly consecutive reductions in estimated corn acres planted, harvested, and yields. Originally, the USDA predicted 2020–2021 corn ending stocks of 3.3 bn bushels—a level not seen since the grain glut years of the mid-1980s.

After slashing corn planted acres (down 6.2 m acres to 90.8 m), harvested acres (down 7 m acres to 82.5 m) and yields (down 179.5 bu/ac to 172 bu/ac), the USDA now expects 2020 corn production will only total 14.18 bn bu, nearly 1 bn bu less than their May estimate.

"CORN YIELDS WERE LOWERED AGAIN WHEN THE USDA FINALLY RECOGNIZED THE STRESS IMPACT FROM EXTREME HOT AND HUMID WEATHER THIS SUMMER ON THE CORN CROP, ESPECIALLY IN THE MIDWEST."

The drop in corn acres planted occurred because of the big COVID-19 pullback in corn prices this spring when $3.00 corn prices discouraged farmers from planting. Acres harvested were reduced an additional 1.5 mm acres after a derecho—a widespread windstorm—knocked down huge swaths of corn in the prime corn growing regions of Iowa back in August. Corn yields were lowered again when the USDA finally recognized the stress impact from extreme hot and humid weather this summer on the corn crop, especially in the Midwest.

Turning to demand, the USDA sharply reduced animal feed and usage demand from its original May estimate of 12.65 bn bushels to 12.03 bn bushels. However, they raised their estimated corn export demand from 2.15 bn bushels to 2.55 bn bushels. Exports offset two-thirds of the weakness in US domestic demand. The net result was a massive reduction in corn ending inventories assumptions—from 3.3 bn bushels back in May to only 1.55 today—the lowest in seven years.

Although not as dramatic, we have seen sizable reductions in the estimates of 2020–2021 soybean ending inventories as well, but for completely different reasons. The May USDA WASDE report projected total soybean acres planted/harvested at 83.5 mm/82.8 mm. Yield assumptions were 49.8 bu/ac, slightly below the record yields of 2016 and 2018. Total soybean crop size was estimated to come in at 4.125 bn bushels. These original estimates were only slightly too optimistic, as acres planted/harvested came in at 83.1/82.4. The soybean crop yield was actually raised up nearly half a bushel, and is now estimated to be 50.2 bu/ac. The soybean crop size is now estimated to come in at 4.14 bn bushel—very close to the original May WASDE estimate.

Given demand and export assumptions, the USDA originally projected 2020–2021 ending soybean inventories to be 405 mm bushes, in line with 20-year averages. However, because of surging Chinese demand, the USDA had to significantly increase export demand. Since their original May WASDE export estimate of 2.05 bn bushels, the USDA has increased export demand by 180 mm bushels. According to the January WASDE report, US soybean ending stocks are now estimated to be only 140 mm bushels. This will be the lowest ending stocks number since the beginning of last decade—when soybean prices approached $18.00 per bushel.

With corn and soybean inventories now significantly reduced, a perfect 2021 planting and growing season is the only way for grain prices to remain stable. Any disruption in 2021 crop growing conditions could put significant upside price pressure on grain prices.

China Becomes a Huge Corn Importer

"UP TO 50% OF CHINA'S HOG POPULATION MAY HAVE DIED OR BEEN CULLED IN 2019 IN RESPONSE TO AN AFRICAN SWINE FEVER EPIDEMIC WHICH STARTED IN 2018."

Two years ago, we wrote how China would soon emerge as a significant corn importer. It now looks as if that time is now. In the last several months, China has made several record corn (and ethanol) purchases from the US. Driving China's short-term demand for corn has been the need to rebuild its hog population. Up to 50% of China's hog population may have died or been culled in 2019 in response to an African Swine Fever epidemic which started in 2018. Besides rebuilding their hog population, China is also expanding its dairy and poultry industries, both of which are big corn consumers. China's corn import needs are now set to surge.

In 2010, China began aggressively encouraging its farmers to plant additional corn acres through subsidies. Chinese 2010 domestic corn production stood at approximately 175 mm tonnes. In response to the subsidies, by 2016, China's corn production had surged to almost 250 tonnes, an increase of over 40%. In response to the surging production, by 2019 Chinese corn inventories surged as well, to 220 mm tones from 50 mm tonnes in 2010. In 2014, the size of China's corn harvest surpassed domestic demand by 45 million tonnes. Since then, China's corn demand has surged. In 2014, China was consuming approximately 215 mm tonnes of corn which reached 280 mm tonnes by 2020. Supply on the other hand has begun to contract. Starting in 2016, China stopped subsidizing corn growers, and supply has now rolled over. After peaking at almost 260 mm tonnes, estimates for the 2020 harvest put Chinese corn production at 250 mm tonnes—almost 30 mm tonnes lower than demand. The Chinese have already disclosed that 57 mm tonnes of corn inventory were auctioned off in 2020, and government officials state no further inventory sales are planned until this spring. Given strong demand and tight inventories, Chinese agricultural sources have indicated that substantial corn imports will be necessary to meet demand and to keep prices from rising. Archer Daniel Midlands, a major consumer of corn, has predicted that China will need to import 25 mm tonnes of corn in 2021. In January 2020, Chinese officials scrapped the ethanol mandate first imposed in 2017 citing "food security" concerns. Such an announcement serves as additional proof that grain markets are rapidly tightening in China.

China has never historically been a substantial corn importer. Global corn markets are now facing a huge new source of demand that literally didn't exist even one year ago, another very bullish development.

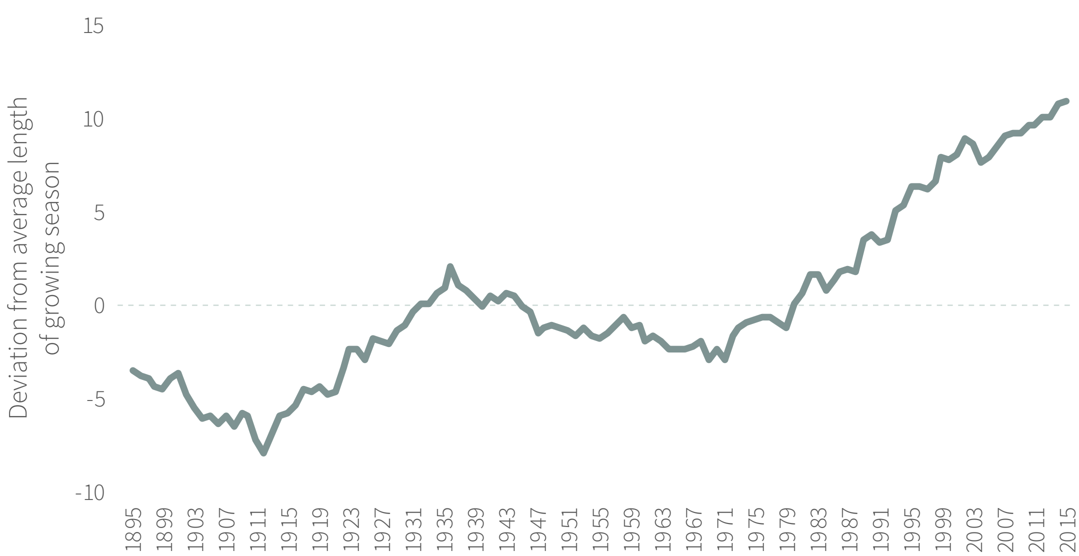
The Weather is About to Change

In our Q4 2019 essay, "Agricultural Markets: What Sunspots Mean for Global Growing Conditions," we wrote about the potential impact of sunspot cycles on global weather patterns. We highlighted how the current warming trend, which began approximately 100 years ago, also happened coincidentally with an unprecedented surge in sunspot activity, now known as the "Modern Maximum." We noted evidence now suggests we are heading into a long period of declining sunspot activity, which could usher in a period of cooler and much more volatile weather.

The 25th sunspot cycle has started, and all indications point to another weak cycle. For example, the Ames Research Center of NASA has published a paper, "Heliophysics Modeling & Simulation Project," that attempts to predict the Sun's sunspot activity levels in this 25th cycle. The paper concluded that the upcoming cycle 25 will be extremely weak, producing a maximum level of sunspots of only 50, as compared to the peak sunspot levels of 120 in cycle 24, peak levels of 150 in cycle 23, and a peak level of 200 in cycle 22. The NASA paper concluded that, the upcoming solar activity levels in cycle 25 would likely be the weakest in the last 200 years. If reduced sunspot activity ultimately results in global cooling, then upcoming weakness in sunspot cycle 25 will confirm a long-term cooling weather trend has begun. 2020 was the second warmest year on record; however, in retrospect, last year might be the peak in this 100-year warming cycle. Historical cooling weather trends have been associated with suboptimal growing conditions.

Although the cooling of the global climate will potentially bring it with extended periods of extremely disruptive weather, one of the major effects will be its impact on the length of the northern hemisphere growing season. As the graph below clearly shows, since 1960, the

FIGURE 3 Contiguous 48 States Growing Season Length, 1895–2015



Source: EPA.

growing season in the United States (a good proxy for northern hemisphere growing conditions) has increased tremendously.

For example, the first fall severe "killer" frost now happens approximately five days later than it did in 1960. In the spring, the latest killer frost has now been pushed back by nearly a week. The longer growing season has produced multiple positive effects. Besides a longer season to grow, the push back in fall frost allows crops further maturation time in case a crop was planted late due to a wet spring. If we are indeed entering a global cooling phase, not only we will see strings of much more disruptive weather events, but killer frosts will occur with much greater regularity in both the late spring and early fall. The net effects will be a severe dampening of crop yields that have grown relentlessly in the last 60 years.

The bull market in global agriculture has begun. Disappointing harvest, the result of adverse weather trends, will collide with strong demand and low global grain inventory. The result will be a massive bull market in grain prices. We believe investors should have maximum exposure to global agricultural equities.

LNG Demand Set to Surge

As already mentioned, we remain very bullish on US natural gas prices, primarily because of rapidly slowing US production. There are other important reasons for believing North American natural gas prices have entered into a long -term bull market as well: the increasing demand for US LNG exports.

The US only began exporting LNG in 2016. Since then, exports have surged as five LNG export facilities have come online. The US today has 10 bcf per day (almost 20%) of LNG export capacity. Given our modeling of LNG demand, and extremely low gas prices here in the US, we believe this export capacity will continue be fully utilized over the next five years. Furthermore, 4.0 bcf/d in new export capacity is currently under construction with an additional 25 bcf per day in new initial-phase projects in various states of approval by the Federal Energy Regulatory Commission (FERC).

Because of the Biden administration's adverse attitude towards hydrocarbon development projects (the just-announced cancellation of the Keystone XL being a good example), we don't know how many of these new projects will go forward. But the demand for this LNG, according to our modeling, will be there as we progress through this decade. Even if just a small amount of this new LNG capacity is built, this will have extremely bullish implications for pricing in the US natural gas market.

Back in 2013, we updated our models for LNG supply and demand. Energy analysts who followed LNG markets back then were incredibly bearish regarding the LNG pricing. Led by huge project expansions in both Australia and Qatar, LNG supply was scheduled to increase by almost 50% in the next seven years. Long term demand for LNG was poorly understood and improperly modelled. Everyone expected LNG prices to experience serious weakness as strong supply overwhelmed weak demand.

Historically, almost all LNG production was priced under long-term contract with the LNG prices linked to the price of oil. However, by 2013, a significant spot market for LNG had developed. Given the surge of new supply without a corresponding increase in demand, consensus thinking believed the long-term BTU pricing link with oil was about to break as spot LNG cargoes effectively flooded the market without being able to find a home. Many analysts believed spot LNG prices (which averaged $15/mmbtu at the time) would fall to Qatar's marginal cost of supply which was approximately $1 per mmbtu.

In retrospect, we know this bearish outlook for LNG prices was wildly off the mark. Long-term contract LNG prices did not break from their oil-priced BTU link, and spot LNG prices (except for the brief period between March and September 2020 when COVID-19 intruded) never traded significantly below $5 per mmbtu. In the seven years since 2013, even in the face of a 50% increase in LNG supply, all new LNG supply was effortlessly absorbed into the market at prices that indicated no market surplus. Both long-term contract prices and spot prices tracked closely to the BTU price equivalency of oil. In fact, in response to a cold snap in Asia back in the beginning of January 2021, global LNG spot prices traded at the highest levels ever. The widely followed JKM (Japan/Korea Market) LNG spot price hit a record $32 per mmbtu. On a BTU equivalent basis, this contract should be worth only $8 /mmbtu.

"WHERE DID ALL THE EXPERTS GO WRONG IN TRYING TO PREDICT THE FUTURE OUTLOOK FOR LNG PRICES? THE ANSWER IS SIMPLE: THE EXPERTS WOEFULLY UNDERESTIMATED THE DEMAND FOR NATURAL GAS, PRIMARILY FROM EMERGING MARKET COUNTRIES."

Where did all the experts go wrong in trying to predict the future outlook for LNG prices? The answer is simple: the experts woefully underestimated the demand for natural gas, primarily from emerging market countries.

In previous letters, we have often talked of the S-Curve's impact on the intensity of commodity consumption in emerging market economies. According to our research, no commodity is more influenced by S-Curve factors than natural gas. Natural gas is an extremely clean, highly desirable fuel, albeit one that is very expensive to use.

Natural gas's biggest problem is that it's neither a solid nor a liquid, but rather a gas. Large transportation and storage investments must be made for natural gas to make significant inroads into a country's fuel mix. By comparison, fuels such as coal are easily transported, handled, and stored, needing little in the way of expensive infrastructure. Because the burning of coal severely degrades the environment, although it is cheaper to use, it is a far less desirable fuel. It is easy to understand why emerging market economies rely primarily on coal for both heating and electricity generating needs while affluent industrialized economies prefer natural gas.

Back in 2013, we modeled the 40 countries that had or would have LNG import capabilities by 2020. Based upon the historical relationship between natural gas consumption and per capita GDP, we estimated that total theoretical global demand for LNG would grow from 32 bcf/d in 2013 to over 70 bcf/d by 2020, an increase of more than 40 bcf/d. Back then, most analysts believed that achieving these consumption figures would be impossible because of the lack of re-gas infrastructure. Announced additions to re-gas capacity made back in 2013 indicated that total global re-gas capacity would grow by 20 bcf per day—to approximately 52 bcf per day in 2020—just barely covering planned supply expansion.

However, our modeling back then told us that over the next few years the perceived bottleneck in re-gas capacity would be resolved through the building of additional import re-gas capacity. Our research led us to believe that analysts were making a common mistake: they assumed infrastructure would drive demand, whereas historically we had witnessed just the opposite. Increased demand, here led by the desire to change the fuel mix away from coal to much cleaner natural gas, would drive the aggressive construction of new re-gas infrastructure. This is indeed what happened. Between 2013 and 2020, total global re-gas import capacity grew by almost 50 bcf per day to reach close to 90 bcf per day of total re-gas capacity—80% greater than estimates made in 2013.

Back in 2013, we modeled that available LNG would increase from 32 bcf to 57 bcf per day. LNG supply in 2019 reached 47 bcf per day. Since the global LNG industry operates at approximately 85% of capacity, this production number was very much in line with our 2013 modeling. Given our robust demand projections that far outstripped supply (40 bcf per day in modelled demand versus approximately 20 bcf per day in new supply), we believed that the global LNG would remain in structural deficit, not structural surplus.

Using China as a case study, it's easy to see how the global LNG market absorbed the surge in supply between 2013 and 2019, and why the structural deficit in the LNG market will only become more severe as we progress through this decade.

Back in 2013, we modelled that China's total energy consumption would grow 6.5% for the next seven years. In 2012, the natural gas consumption represented less than 5% of China's total energy mix versus 17% in South Korea, 13% in Taiwan, and 21% in Japan. China back then was literally choking on its coal-related air pollution leading the government to announce plans for natural gas consumption to reach 10% of the county's energy mix by 2020. Using these projections (which were very much in line with our models), we predicted China's natural gas demand would grow 19% per annum, going from 15 bcf/d to 50 bcf/d by 2020—a staggering 35 bcf/d increase.

Our modeling assumed China's domestic natural gas production would double—going from 10 bcf/d to 20 bcf/d, while pipeline imports from Turkmenistan, Myanmar, and Russia would grow from 2 bcf/day to 13 bcf/d. The deficit between demand and land-based supply would need to be filled by LNG imports which would grow from 2.5 bcf/d in 2013 to 17 bcf in 2020—a surge of 14 bcf/d.

Looking back, many of our assumptions were off, but the direction was correct. Total energy consumption in China only grew 4% annually during that period versus our modelled 6.5%. Much of the shortfall can be explained by the Trump-related trade war. Natural gas consumption increased to only 31 bcf/d versus our modelled 59 bcf/d, but domestic gas production and pipeline imports both significantly disappointed as well. Domestic production hit 18 bcf per day and total pipeline imports hit only 4.6 bcf /day—a significant shortfall versus our modeled 13 bcf/d. LNG imports have now reached 8 bcf per day, representing 8% of China's energy mix. However, even with our overoptimistic modeling of demand, China itself has consumed over 60% of the increase in global LNG supply over the last seven years.

Looking forward, China's LNG importation numbers could be huge. If total energy consumption only grows by 3% over the next five years, and if China hits its goal of 15% gas penetration of its energy mix, consumption will hit 65 bcf /day in 2025—up 35 bcf/day from today. Given the slowdown now taking place in China's domestic gas production (a combination of slowdown in conventional production and disappointing shale gas production) we calculate Chinese supply will only grow 3 bcf /day reaching 21 bcf/d in 2025. Ramping up Gazprom's pipeline gas from Eastern Russian by almost 4.9 bcf per day by 2022 and completing pipeline "D" from Turkmenistan will add an another 3 bcf per day of new pipeline supply.

Given these expansions, we believe pipeline supply of natural gas will grow from 4.5 bcf/d in 2020 to over 12 bcf/d in 2025. However, even given these large expansions, the gap between Chinese consumption and its land-based sources of supply will grow considerably wider. By 2025, China will have to import over 30 bcf/d of LNG to satisfy internal demands, an increase of 22 bcf/d from 2020 levels. The global LNG industry is planning on adding almost 40 bcf/d in new liquefying capacity by 2025, and, if our modeling is correct, China will consume over 50% of this new capacity.

And then there is India, a country that we have highlighted over the last several years in our various energy discussions. In the last 10 years, due to rapid economic growth and its surging coal consumption, India has developed a severe pollution problem. Much like China, India has expressed its strong desire to aggressively increase its natural gas consumption. Natural gas consumption represents only 6% of India's energy mix (coal represents 55%) and, like China, India has announced a plan to push natural gas to 10% of their energy mix by 2025, and to 15% in 2030. In order to accomplish this, the Indian government is now investing $60 bn to build out its pipeline infrastructure and its ability to import LNG. India has six LNG import terminals in operation today with four additional terminals scheduled to come online by 2023, bringing LNG import capacity to almost 8 bcf/d, very much in line with our modeling of what will be needed.

At present, India is consuming approximately 6 bcf/d of gas: domestic gas production amounts to 3 bcf/d while 3 bcf/d of LNG fills the gap. Because India is surrounded by hostile neighbors, it imports no gas via pipeline and has no plans to do so in the future. If energy consumption in India grows at 3% per year for the next five years and natural gas use reaches 10% in the energy mix, India would consume almost 12 bcf/d of gas. Given the lack of exploration success in the KG basin off the east coast of India, we believe that Indian gas production will only increase by at most 1.5 bcf per day by 2025 to 4 bcf/d. LNG imports will have to rise to 8 bcf per day (up 3 bcf/d from today) in order to fill the gap between demand and supply. Given India's historical problems of pricing natural gas and its lack of infrastructure, this huge increase in LNG import will be hard to achieve in the next five years, but it shows that the pressure is on.

If our modeling is correct, we project that China and India together will consume almost 75% of all new LNG supply in the next five years. Outside of China and India, the pressure to increase natural gas consumption in the developing world remains intense. In the OECD world, gas consumption represents 28% of the energy mix, and coal represents only 14%. In the non-OECD/non-FSU world (the FSU is unusually gas dependent given its abundant domestic resources), natural gas consumption represents only 18%, and coal consumption represents 40%. Given the rapid economic growth in the non-OECD/ non-FSU world and its desire to shift from coal consumption to natural gas we expect demand to surge. Our modeling tells us that if total energy demand grows by 3% per year and natural gas goes from only 18% to 20% of the energy mix, then gas consumption will grow by 70 bcf/d from 205 to 275 bcf/d by 2025. Most of this gas will have to be supplied by LNG overwhelming the 40 bcf/d of new expected supply.

Which finally brings us back to the bullish demand story for US natural gas. Given the severe imbalance between global LNG demand and supply, we believe that demand for US LNG will remain robust and that present export capacity (approximately 10 bcf/day) will operate at near 100% capacity over the next several years. Also, the US has almost 5 bcf/d of LNG export capacity that is fully permitted and now under construction. The new Calcasieu Pass LNG project is expected to come online with 1.4 bcf/d in 2022. Tellurian's Driftwood Project (stage 1) is expected to come online in 2023 with 1 bcf/d of capacity, and Exxon's GoldenPass LNG project is projected to come online with 2.5 bcf/d of capacity in 2025. Our modeling shows that strong growth in US natural gas supply has come to a halt and that the demand created by LNG exports, including another 4–5 bcf per day in additional expansions in the next five years, means that, gas could very well trade at a BTU equivalent—something the US gas market hasn't seen in over 12 years. At $50 per barrel for oil, this would translate to a $8/mmbtu gas price, almost 3 times higher than the $2.70 per mmbtu price at which gas trades today.

Oil Markets Now in Deficit

Global crude oil markets are firmly in deficit. After peaking in June 2020 at 388 mm barrels above seasonal averages, OECD inventories drew by 109 mm bbl by November suggesting a deficit of 700,000 b/d—the second largest five-month decline on record. Initial data from the US (which makes up the majority of global stockpiles) suggests the deficit has accelerated. Since November, total US petroleum inventories have drawn by over 1 mm b/d relative to seasonal averages while core inventories (crude, gasoline, distillate, residual fuel oil and jet fuel) have drawn by nearly 600,000 b/d.

Despite the major dislocations in the spring of 2020 that saw WTI turn negative, oil prices are now higher than they were one year ago, before the impacts of COVID-19 had extended outside of Wuhan. Both Brent and WTI markets are once again backwardated (where the future price is lower than the spot price), implying physical market tightness. The backwardation is now as high as it was in the fall of 2019.

Although inventories have been coming down sharply, they remain higher than seasonal averages after the extreme runups last spring following coordinated global COVID restrictions. When we laid out our predictions for the second half of 2020 last summer, we expected inventories would draw by as much as 10 mm b/d, completely eliminating the inventory overhang by year end. In our last quarterly letter, we pushed this milestone out to sometime in the first half of 2021 and this now looks to have been correct. Based upon our models, we believe global excess inventories will have been completely worked off by the end of Q1 or early into Q2.

"CHINESE DEMAND HAS BEEN RUNNING AT RECORD YEAR-ON-YEAR GROWTH FOR SEVERAL MONTHS AND NOW INDIAN GROWTH IS ACCELERATING AS WELL AND HAS MADE AN ALL-TIME NEW HIGH."

Global demand has run behind our expectations as a second wave of COVID-19 led to renewed travel restrictions around the world during Q4. Notably, jet fuel demand remains depressed while gasoline, distillate, and residual fuel oil demand has steadily recovered. We anticipated demand largely getting back too normal by the end of 2020; this was too aggressive. However, with the widespread rollout of an effective vaccine as we progress through the first half of 2021, we believe demand will soon surge once the lifting of travel restrictions meets pent-up global demand. Chinese demand has been running at record year-on-year growth for several months and now Indian growth is accelerating as well and has made an all-time new high.

US shale production remains depressed. When we last wrote, we explained how the restarting of thousands of shale wells that had been shut-in to avoid "full storage" in the spring were confounding analysts. In particular, oil bears worried perhaps shale growth was returning after seeing monthly production increases. We explained how our neural network suggested shut-in wells would come back online during Q3, providing a one-time bump to US shale production before rolling over again in Q4. As of December, all the shut-in wells had been returned to production and yet US shale production remained 1.4 m b/d lower than one year earlier, confirming our analysis. Other than May (when 1 m b/d was being actively shut-in), the shales have never experienced a comparable year-on-year decline in their history.

Moreover, the EIA predicts the shales will lose another 200,000 b/d between December 2020 and February 2021.

For the first time in a decade, the only material source of non-OPEC+ production growth is suffering sustained declines. Our models tell us this will continue as we progress throughout 2021. The reason has to do with the exhaustion of the "core" areas of the three major shale basins: the Permian, Eagle Ford and Bakken. As we have discussed at length, our neural network warned us the very best areas of these basins were quickly being drilled out. We argued that shale productivity would be negatively impacted, making production growth much more difficult. This is exactly what has happened. Productivity fell for the full year in 2019 in the Eagle Ford and Bakken for the first time ever since shale development began while the Permian experienced its slowest productivity growth ever. In 2020, the industry laid down nearly 80% of their rigs in response to the record low oil prices of Q2. In past cycles, this would have resulted in surging productivity as companies focused on only their best prospects. Instead, between Q1 and Q3 of 2020, we estimate that drilling productivity (as measured by expected 3-month initial production) likely fell in the Permian and Bakken and was flat in the Eagle Ford. Based upon preliminary data, it does not appear that full year productivity fell for the second consecutive year, but it came close. Given the incredible slow-down in drilling activity in 2020, the near-decline in drilling productivity for the full-year is further proof of resource exhaustion.

As prices recovered, US oil-directed rigs have started to pick up, but our models suggest the activity remains well below levels necessary to hold production flat, let alone grow. After having bottomed at 172 rigs in August, the US oil-directed rig count is up 80% to 310 rigs. While this may seem like a sharp increase, it is still less than half the level of early 2020, at which point shale production was declining sequentially. Even after increasing our rig count assumptions for 2021, our models continue to suggest total US crude production will decline by 700,000 b/d compared to 2020 (and nearly 1 m b/d December to December).

Non-OPEC+ production outside the US continues to decline as well. Like the US, other non-OPEC+ countries curtailed production where possible in response to extreme low prices in 2020. Led by Canada, non-OPEC+ production outside the US fell by 1.4 m b/d in Q2 compared with a year earlier. Despite Canadian production largely returning, the group's production remained 1.3 m b/d lower in Q4 year-on-year as declines in other countries took hold. The International Energy Agency (IEA) expects non-OPEC+ production outside the US will rebound sharply in 2021, ultimately growing by 800,000 b/d. We continue to believe this is unlikely. Even before COVID-19 related activity slow-downs, there were simply not enough new projects coming online to offset base declines. We wrote about these trends in our Q2 2020 letter and plan on revisiting the topic in our next letter. With Canadian production now back online, any spare capacity is gone. The only growth will come from new projects and there are simply not enough, a subject we have discussed extensively in previous letters.

Turning to the balances for 2021, we expect to see continued inventory drawdowns as we progress through the year. The IEA currently expects global demand to average 96.6 m b/d —growth of 5.4 m b/d year-on-year but still 3.4 m b/d off 2019 levels. Production from the US is expected to decline by 300,000 b/d year-on-year while the rest of non-OPEC+ grows 800,000 b/d resulting in total non-OPEC+ production of 51.3, leaving the call on OPEC+ at 45.3 m b/d. Current OPEC+ production is 40.3 m b/d while total "baseline" production (i.e., if all quotas were removed) is 46.9 m b/d. This implies that OPEC+ could roll back 75% of their production cuts without pushing the market into surplus.

While the IEA's projections are fairly bullish, we believe the true balances are actually much tighter. Although we admit to being premature in calling for normalized demand in 2020, we expect a return to normal once the vaccine is rolled out throughout the first half of 2021. Given recent data from key oil consumers such as China and India, we believe we may be on the verge of a demand boom that could take total consumption well past the prior high of 100 m b/d. We are modeling 99 m b/d for the full year 2021. Instead of falling by 300,000 b/d, we believe US production will fall by nearly 1 m b/d without a material increase in drilling activity. For the rest of the non-OPEC+ producers, our models suggest production will fall by 500,000 b/d instead of growing by 800,000 b/d. Instead of averaging 51.3, we believe total non-OPEC+ production will only reach 49.3 m b/d. This would leave the call-on-OPEC+ at 49.7 m b/d – 3 mm b/d more than their fully restored "baseline" production.

Given OPEC+'s commitment to normalize global inventories, we believe they will only modestly adjust quotas for the time being. As a result, both US and global inventories will likely continue their decline as we progress through the year. Already we are seeing near-record inventory draws suggesting the market is already in structural deficit. The backwardation in both WTI and Brent confirms this physical tightness. At the same time, oil stocks (as measured by the XOP ETF) remain nearly 30% below their January 2020 levels. The last year has been extremely chaotic for investors in general and oil investors in particular. Our models tell us the worst is behind us and that a lack of capital investment has set up the potential for multiple energy crisis as we progress through this decade. The data is extremely bullish, and we continue to recommend a full position in oil stocks.