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THE ENERGY CRISIS IS HERE

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"Europe's Energy Crunch Sparks Panic in Asia and Dash to Buy Fuel" Bloomberg, September 16th 2021

"Europe's Energy Crisis Is Coming for the Rest of the World, Too" Bloomberg, September 27th 2021

"European Energy Prices Surge to Records as Supply Crisis Spreads" Bloomberg, September 28th 2021

The Energy Crisis is Here

The energy crisis unfolding across Europe, Asia, and South America caught almost everybody by surprise – but not our readers, we hope. Our 2Q20 Natural Resource Market Commentary was titled "On the Verge of an Energy Crisis." Fast forward 14 months: the energy crisis we predicted has arrived with a vengeance.

Yet, we assumed the energy crisis would first hit global crude markets and then spill over into natural gas. Instead, the opposite has occurred: tightness in global gas markets is now impacting crude.

We thought extremely strong oil demand, coupled with a feeble rebound in non-OPEC production, would lead to a situation never seen in 160 years of crude history: demand would actually surpass global pumping capability by the end of 2022. Even during the two energy crises of the 1970s (the Arab oil embargo of 1973 and the Iranian hostage crisis of 1979), crude demand did not come close to exceeding global pumping capability. Recent data strongly suggests our modelling was correct: demand will exceed pumping capacity by the end of next year.

In retrospect, we know that natural gas markets, not oil markets, were the first to slip into severe deficit (we should point that we were also extremely bullish on gas, and we maintained strong exposure to natural gas investments as well). Low inventory levels, extremely strong demand, and disappointing output from renewable sources (primarily wind and hydro), have caused European and Asian natural gas prices to soar.

By September 2021, prices in Europe and Asia reached between $32-33 per mmbtu, equivalent to a crude price of $200 per barrel based on the energy contained in each. In a frantic attempt to meet demand, European and Asian buyers have turned to spot liquefied natural gas cargos only to realize that global LNG markets have also slipped into a severe structural deficit. Again, our readers should not be surprised. In our 4Q20 letter we wrote: "LNG Demand (Is) Set to Surge." We discussed how global natural gas demand would outstrip all sources of supply. Natural gas balances are now at dangerously low levels, especially in Europe. The slightest bout of colder than normal winter weather could have catastrophic impacts as shortages develop and prices surge. The crisis now gripping natural gas will only be the first of many energy (and agricultural) crises that emerge in the next five years.

Investors need to recognize how interlocked energy markets have become. A crisis in one market is all but certain to spill over into another. European utilities are desperately switching from burning expensive natural gas to much less expensive crude oil, increasing demand by over 500,000 b/d. This additional source of demand has introduced even more tightness into an oil market that is already undersupplied. The oil crisis we had originally expected to emerge in 4Q22 will now likely come even sooner. As the natural gas shortage did, the coming oil crisis will seemingly come out of nowhere, taking much of the investment community by surprise.

Energy markets are also tightly bound to global agriculture. We believe agricultural markets are primed to slip into crisis at some point this decade. As energy shortages have spread, many fertilizer and soybean processing plants in China and the UK have already been shut. We will discuss the connection between the unfolding energy crisis and global agriculture later in this letter.

How did this energy crisis emerge so quickly and unexpectedly? The most important cause has been the ongoing underestimation of global energy demand. In turn, this resulted in dramatic underinvestment in oil and gas development.

Over the last 20 years, there has been a surge of energy demand, a phenomenon we call the

“S-Curve.” As a country gets richer, energy demand grows faster than economic activity for a period of time. We estimate that in 1995 approximately 700 mm people were in the midst of their “S-Curve.” Today, there are almost 4 billion people in this category – the most in history.

Coinciding with the explosion of energy-hungry consumers is the misguided focus on renewable energy over the last 10 years. Mounting ESG pressures forced energy companies to significantly reduce their traditional hydrocarbon investment while dramatically increasing commitments to renewable energy projects. Wind and solar have a fundamental problem: they are intermittent and therefore unsuited for baseload power.

We have argued that surging demand from the S-Curve combined with a reduction of traditional energy capital spending would prove unsustainable. The result is the energy crisis unfolding today. We are still in the very early innings of this new cycle.

In the short term, the biggest variable is the weather. As many of our readers know, we believe we are entering a prolonged cooling phase that will produce many unfortunate and unforeseen outcomes. Evidence continues to emerge suggesting we have entered into a long phase of reduced sun-spot activity. Typically, these periods are associated with longer, colder winters, shorter growing seasons, and more violently destructive weather.

Although this past Northern Hemisphere summer was one of the warmest on record, the Southern Hemisphere winter was just the opposite. An extensive winter storm led to near-record low temperatures and left large swaths of southern Brazil blanketed under snow for the first time in 65 years. An incursion of cold Antarctic air produced one of the worst freezes in the heart of Brazil’s coffee growing region, sending coffee bean prices soaring. And although it has garnered absolutely no press, Antarctica has just experienced its coldest winter on record, leaving its sea ice at the fifth highest reading since records began in 1979.

Given that we are now well into our third consecutive 11-year sunspot cycle with lower sequential maximal activity, and that Eastern Pacific ocean conditions point to a moderate La Niña, we believe the risk of a severe Northern hemisphere winter is real. Russia experienced its coldest September in two decades while Europe broadly has had a cold start to autumn. A colder than normal winter would have a catastrophic impact on already depleted natural gas inventories.

Oil markets will likely be the next to undergo severe stress. Inventories have drawn at a record pace and now stand well below normal. Non-OPEC production growth has disappointed while strong demand continues to surprise.

Last quarter, we discussed the International Energy Agency’s latest climate policies and how they would produce unintended consequences. One consequence that has emerged even faster than we had expected: OPEC’s regain of market share and pricing power.

Despite having aggressively promoted legislation that echoed the IEA and discouraged domestic oil production, on August 11th 2021 the Biden administration called on OPEC to increase production to help ease high prices. OPEC rejected Biden’s request and crude prices having rallied over 20% since.

The energy crisis has just started. Over the next decade, this new cycle will unfold with many unanticipated twists and turns. The investment implications and opportunities remain incredibly large. In an ironic twist, institutional investors have little to no exposure to energy stocks. We would not be surprised if energy ended up representing investors' single largest exposure at some point before the decade is over.

For all investors, we continue to recommend maximum exposure.

The Incredible Shrinking Oil Majors -- Part 2

"Chevron Girds for Activist Challenge After Exxon's Proxy Battle Defeat" Wall Street Journal, September 3rd 2021

"Exxon Debates Abandoning Some of Its Biggest Oil and Gas Projects" Wall Street Journal, October 20th 2021

"Aramco Warns World's Spare Oil Supplies are Falling Rapidly" Bloomberg, October 26th 2021

The super-majors' problems continue to mount. Last quarter in "The Incredible Shrinking Oil Majors," we discussed their inability to replace production with new reserves and how production of both oil and gas would significantly disappoint as we progressed through this decade -- especially considering the collapse of upstream capital spending budgets last year. We also discussed the forces now being applied to the companies by various ESG groups, both shareholders with de minimis ownership and various court systems, and how these forces would only exacerbate the reserve replacement and production problems being faced by these companies today.

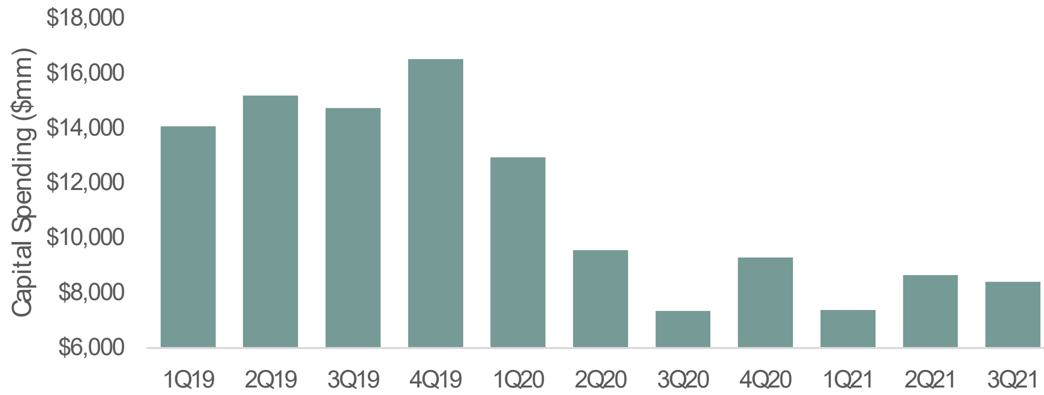
A number of recent developments merit discussion. Both capital spending and production of oil and natural gas continue to fall for the four super-majors (Exxon, Chevron, Royal Dutch Shell and Total Energies). In 2019, upstream capital expenditures averaged $15 bn per quarter for these four companies. Upstream spending collapsed in tandem with oil prices in 2020; by 1Q21 it had fallen by over 50%. Even though oil prices have rebounded, capital spending has lagged far behind, trending upward in 2021 off last year's low, but still well below 2019 levels.

The large drop in capital spending has already put notable pressure on oil and gas production across the four super-majors. The surge in finding and development costs over the previous decade, combined with any extended drop in upstream capital spending, will produce large drops in reserve replacement and production going forward.

Our models originally suggested hydrocarbon reserve replacement will fall to only 40% while production itself will fall over 30% by 2030 unless capital spending trends move much higher. It now looks like the severe drop (and weak subsequent rebound) in capital spending over the past 20 months is already pressuring oil and natural gas production. Super-major production has now fallen over 10% since the beginning of 2019.

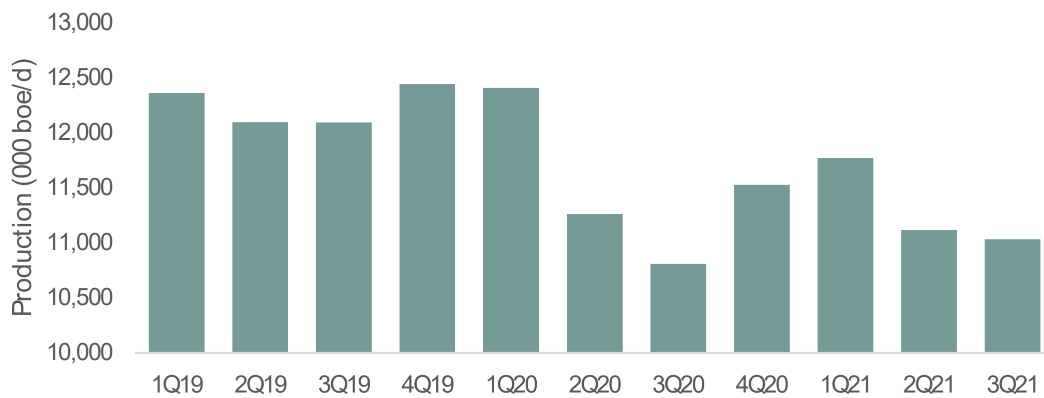
Three out of the four super-majors face intense ESG-related scrutiny.

FIGURE 1 Super-Major Capital Spending



Source: Company Filings

FIGURE 2 Super-Major Hydrocarbon Production



Source: Company Filings

After successfully replacing 25% of Exxon's board of directors despite owning just 0.02% of the outstanding equity, Engine No. 1, the climate-focused activist hedge fund, met with Chevron's management late last summer. In discussions that were later described as "cordial," Chevron executives shared their plan to reduce carbon emissions. Subsequently, Chevron announced new plans to further reduce carbon output, along with their intention to appoint a new director with "environmental expertise." Although it remains unclear exactly what Engine No. 1 is planning, rumors suggest the fund has contacted other investors, strongly suggesting they intend to launch a second campaign in the not-too-distant future.

What should Chevron expect?

It was recently reported by The Wall Street Journal that Exxon was considering abandoning two massive natural gas projects: the 75 trillion cubic foot (tcf) Rovuma LNG project (capital cost $30 bn) and the 5 tcf Ca Voi Xanh offshore-Vietnam gas project (capital cost $10 bn). Exxon board members (most likely including the three supported by Engine No. 1) have publically expressed concerns about both projects.

According to internal reports, these projects are among the highest CO_2 producers in Exxon's pipeline; it is no surprise these projects have been called into question. However, we find the plight of both fields to be perplexing since production would almost certainly be used to displace coal in electricity generation, cutting CO_2 emissions by nearly 50%. This fact seems to be lost on the new Exxon board members.

Vietnam's electricity generation is 50% coal-based while only 8% comes from natural gas. The country has stated its long-term goal is to have 80% of its electricity come from natural gas. If Vietnam is successful in its ambitious goal, it would reduce carbon emissions by nearly 30%. The development of the Ca Voi Xanh field is a critical part of this plan.

Similarly, large volumes of Rovuma LNG will likely go to displacing coal in India. Only 7% of all Indian electricity comes from natural gas while coal represents 55%. India wants natural gas to represent 15% of its energy mix by 2030. Cancelling the Rovuma LNG project would certainly complicate this goal with large implications for CO_2 reduction.

A global natural gas shortage has already developed and we believe this is only the beginning of a long period of structural deficit. The world desperately needs the development of massive natural gas fields like Ca Voi Xanh and Rovuma to meet demand going forward.

Royal Dutch Shell's ESG challenges continue unabated. A Dutch court ruled in May that Royal Dutch Shell must cut its CO_2 output by 45% by 2030 to align their policies with the Paris Climate Accord. In a statement issued after the verdict, a Shell spokesperson acknowledged that "urgent action is needed on climate change and the company is accelerating efforts to reduce emissions." If the pressure from the Dutch court system was not enough, an activist shareholder has proposed breaking the company apart to address ESG concerns. On October 27th, Third Point Management announced the following.

"If Shell pursues this type of strategy it would probably lead to an acceleration of carbon dioxide reduction. […] Breaking Shell into two operating units would create a standalone legacy energy business (upstream, refining, and chemicals) that could slow capex beyond what is has already promised, sell assets, and prioritize return of cash to shareholder which can be reallocated into low-carbon areas of the market."

Shell has already cut spending dramatically over the last decade. After having peaked at $39 bn in 2013, upstream capital spending fell to only $17 bn in 2020 – a drop of nearly 60%. Spending has barely recovered in the three quarters of 2021. A lack of spending has already impacted production. Proforma for the 2016 acquisition of BG Group, Shell's total production has fallen 13% since capital spending peaked in 2013. These trends are accelerating: Shell's production over the first nine months of 2021 have fallen 7% compared with the same period last year.

If Royal Dutch Shell's upstream capital spending remains at today's depressed levels, we estimate the company will only be able to replace 30% of production with new reserves and that production will fall 40% over the next nine years. If spending is further curtailed (as is being proposed), Shell's oil and natural gas production would collapse – something that may have already started.

As we have outlined many times in these letters, we believe growth in non-OPEC+ oil supply will turn negative this decade. The issues faced by the super-majors are a great example of pressures exerted on the energy industry as a whole.

As non-OPEC+ production declines, OPEC will gain ever more market share and pricing power. The first oil crisis of the 21st century is now upon us. You have to look no further than the plight of the super-majors to see why.

Natural Resource Market Commentary -- 3rd Quarter 2021

Commodity prices advanced in Q3. Delta variant concerns were offset by strong underlying fundamentals across multiple commodity markets. The energy-heavy Goldman Sachs Commodity Index rose 5.2% on a total return basis, while the Roger International Commodity Index, with its higher exposure to metals and agriculture, rose 6.2%. Natural resource-related equities were weaker, reflecting the increased threat of further COVID-19-related lockdowns.

The S&P North American Natural Resources Sector Index, which is very heavily weighted to North American energy stocks, fell 2.5%. The S&P Global Natural Resource Index, which has significantly more metal and agricultural stock exposure, fell 3.1%. The broad market, as measured by the S&P 500 Stock Index, rose by 0.6%.

Oil Markets

Energy markets were firm in Q3. West Texas Intermediate (WTI) rose 2% and Brent rose over 4%. Global oil and refined product inventories continued to draw sharply in Q3 as demand exceeded expectations and OPEC+ quota compliance remained strong.

We continue to expect the oil crisis will take place as we progress through 2022.

How high could oil prices go? While it is difficult to say (bull markets often go much farther than anyone expects) the natural gas market might provide a clue. Asian LNG prices have just hit $300 per oil equivalent barrel when adjusting for energy content. Could oil prices surge that high? Please read the oil section of this letter to find out.

Gas Markets

Henry Hub natural gas prices were extremely strong in Q3, advancing over 60%. International natural gas prices were even stronger, making them by far the best performing commodity during the quarter. European and Asian natural gas prices surged over 150%. We are bullish on natural gas and recommend investors maintain significant exposure to the related equities.

Europe is on the precipice of a natural gas crisis and we believe the US will soon follow. Natural gas inventories are 5% below normal in the US as we enter the withdrawal season. Production meanwhile is still 4% below its year-end 2019 level and drilling activity remains subdued despite much higher prices. Prices could spike if North America experiences a colder than normal winter. Please read our Natural Gas section where we will discuss each of these in greater detail.

Coal Markets

Coal prices soared during Q3. Australian thermal coal surged 40% while both South African thermal coal (as measured by the Richard's Bay benchmark) and seaborne metallurgical coal (used for steelmaking) advanced by 75%. We have not made any coal investments and are often asked whether we will going forward. We remain conflicted regarding global coal markets for a variety of reasons. As some of you may know, we were substantial coal investors in the past and still follow the fundamentals closely.

Even more than the oil industry, coal has come under extreme pressure by ESG considerations. The coal industry has been starved for capital for over a decade and instead of investing in their assets, major coal producers have announced plans to shut or divest operations. Demand, meanwhile, has been steady as falling OECD demand has been more than offset by rapidly expanding emerging markets. As natural gas shortages have emerged, Asian fuel buyers have turned towards coal in search of BTUs, causing prices to surge. Moreover, we cannot help but notice that coal has outperformed during every natural resource bull market over the past 120 years.

On the other hand, there are very real environmental concerns threatening coal's viability going forward. Policy makers and investors have become extremely conscious of carbon emissions and have advocated against coal-based electricity generation. Gasoline powered automobiles have come under similar pressure and yet we continue to recommend oil investments -- what explains the difference? In the case of oil, the alternative to the internal combustion engine is the electric vehicle. As we explained in our 3Q19 letter, the EV will do little to reduce carbon per passenger mile travelled and may actually increase total emissions. In the case of jet fuel and petrochemical manufacturing, there is no alternative to crude. Therefore, while ESG pressures mount (creating opportunity), the long term fundamentals remain sound.

The same may not be true for coal. Natural gas can generate electricity at less than half the carbon intensity. Nuclear power can generate reliable base-load power with no carbon at all. The recent natural gas shortage has created a tailwind for coal demand. Over the longer-term however, we do see alternatives, such as gas and nuclear, that can dispatch uninterrupted baseload electricity while emitting much less carbon than coal. So long as investors remain focused on carbon, this will be a persistent headwind for coal.

We must admit to being torn between extremely depressed valuations, near term positives, and longer term challenges. At present, we do not hold any coal investments, however we may change our minds depending on how the current energy crisis progresses.

Uranium Markets

Uranium prices surged during the quarter as financial players bought aggressively -- a prediction we first made in our 3Q2018 letter. Spot prices rallied from $32 per pound at the end of June to $50 by mid-September before pulling back and ending the quarter at $43. Please read the uranium section of this letter to learn more. Also, please visit our website (click here) to watch a new video that discusses the history of energy and the future potential of nuclear power. Our video covers critical issues that we have never seen discussed anywhere else. The implications are huge. After you watch our presentation, you will understand how nuclear power offers a solution to our current climate problems as well as to our concerns regarding future economic growth.

Agriculture Markets

Grain markets were mixed during the quarter. Corn and soybean prices were weak, falling 25% and 13%, respectively, as drought conditions eased somewhat in the US Midwest. Wheat prices rallied 8%, driven by little rain across the Former Soviet Union (FSU). Coffee was the standout performer as a severe frost gripped the Brazilian growing region in July. Bean prices surged 25% during Q3 and have advanced over 60% for the year.

Fertilizer prices also continued their climb. Urea advanced by 60% while potash advanced by 30% and phosphate advanced by 10%. Year to date, fertilizer prices are the commodity market leaders. Urea and potash prices are up 160% while phosphate prices are up 70%. We remain very bullish regarding grain prices and are maintaining our large exposure to fertilizer producers. For further comments on global agricultural markets, please read the agriculture section of this letter.

Base Metal Markets

Base metals and their related equities were mixed in Q3. Nickel fell 2% while zinc rose 1% and aluminum rose a strong 13% as Chinese electricity shortages impacted supply. Over the last 25 years, China has gone from producing less than 1% of global aluminum to over 55% today. Most of this increase was the result of cheap electricity, much of which is generated from coal. A prolonged electricity shortage would help support aluminum prices which have been under a 20-year assault from surging Chinese production. Our favorite base metal remains copper. After making a new all-time high in May, copper pulled back by 7%, however we remain steadfastly bullish. Metal equities were weak during the quarter. Copper stocks, as measured by the Global X Copper Miners ETF (COPX) pulled back 7% while the S&P/TSX Global Base Metals Index ETF (XBM) pulled back 5%. Please see the copper section of this letter where we discuss recent examples of the supply problems developing in global copper markets.

Precious Metal Markets

Precious metals were weak during Q3 as their year-long price consolidation phase continues. Gold fell 1% while silver fell 14%, platinum fell 10%, and palladium fell a large 30%. Gold and silver-related equities were weak for the quarter as well. Gold stocks (as measured by the GDX ETF) fell 13% while silver stocks (as measured by the SIL ETF) fell 18%.

For the year through September, gold prices fell 8% while silver prices fell 15%. Gold and silver equities fell 18% and 23% respectively. Although we continue to believe a bull market lies ahead, for now we expect the ongoing corrective phase will continue.

On the positive side, central banks have resumed their gold purchases after a pronounced slowdown beginning late last year. Starting in the second half of 2020, central banks slowed their gold purchases reaching only 45 tonnes in Q4 – a decline of nearly 70% compared with a year earlier. Although central bank purchases remained weak during the first two months of 2021, they have now surged.

For the first six months of 2021, central banks purchased 330 tonnes of gold -- a pace rivalled only by 2013 and 2019. Sizable purchase were made by Thailand (90 tonnes), Brazil (54 tonnes), Uzbekistan (26 tonnes), India (29 tonnes) and Cambodia (5 tonnes).

Of notable interest, Turkey purchased 14 tonnes in the first half of 2021. Turkey had been a large gold buyer in 2019 and the first half of 2020, before turning into a net seller during the second half of 2020. It appears as though Turkey is once again buying.

Gold demand in both China and India have now rebounded to pre-COVID levels as well. On the bearish side, Western investor demand for both gold and silver (as measured by flows into various precious metal ETFs) remains lackluster.

We ultimately expect the upcoming gold bull market to be driven by Western investor demand. This would be completely different than the bull market between 1999 and 2012 which was largely dominated by Eastern buying.

To show the importance of the Western buyer to this gold bull market, please note that the 16 physical gold ETFs we track began accumulating gold in 4Q18 -- just as the gold market began its advance.

Over the next 18 months, these physical ETFs grew by 60%, accumulating 1,220 tonnes. Gold peaked at $2,065 per ounce in the first week of August 2020, having advanced 70% from the 4Q18 low. The ETF gold holdings peaked in the first week of September at 3,250 tonnes, just one month after the gold price. Since then, the ETFs have turned into chronic liquidators of gold. After having shed 180 tonnes of gold in 1Q21, the ETFs sold an additional 60 tonnes in Q3.

As Q4 gets underway, Western interest in both gold and silver (as measured by the physical ETF flows) continues to be weak with gold holdings down slightly and silver flat.

In 3Q20 we worried how silver's furious catch-up rally with gold signaled a period of consolidation across all precious metals, just like it had every other time silver caught up to gold over the last 50 years.

On a long term basis, before the bull market is over, we expect gold to reach in excess of $15,000 per ounce. However, we admit that even during the 1970s precious metals bull market, gold went through frustrating periods of price consolidation within the broader rally. After the Fed began raising interest rates in the summer of 1973, gold and silver both pulled back 45% over the next 30 months before eventually exploding in price.

We firmly believe today's inflation is not transitory and expect the Fed will ultimately be forced to raise interest rates over the coming years. If we repeat the 1970s experience, precious metals could experience significant weakness as the Fed attempts to raise rates. For patient investors, we believe an excellent buying opportunity will present itself sometime over the next 12 months. For investors with long-term investment horizons, we believe the present weakness in both gold and silver and related equites can be used as buying opportunities. For those with performance constraints, we prefer waiting and investing in securities that will benefit from the rapidly progressing energy crisis.

Running Out of Global Pumping Capacity

Global oil markets could not have looked grimmer than back in the summer of 2020. COVID cases were increasing again and further global economic lockdowns were being threatened. Only two months before, oil prices had crashed into negative territory for the first time in history as global inventories had surged and threatened to overflow. Between the never-ending pandemic and electric vehicles, common investment wisdom believed oil demand was in secular decline, bloated inventories would remain elevated forever, and oil prices would never recover.

At Goehring & Rozencwajg, we love to undertake in-depth insightful research that identifies newly developing investment trends and often comes up with conclusions that differ vastly from consensus opinion. Our goal is to share these results with our investment clients and partners at least twelve months before they become headline news in the financial press. This is an ambitious goal and we don't always get it right. However, the satisfaction in recognizing trends long before the general investment community not only brings large profits to our investors, but a huge amount of professional pleasure to us as well.

To that end, we titled our 2Q2020 letter "On the Verge of an Energy Crisis". At the time, no one agreed with us. Now headline after headline talks of an "unforeseen" energy panic. It looks like the energy crisis we discussed 14 months ago is now here.

If the energy crisis has arrived, where does Goehring & Rozencwajg see things 12 months from now? By the end of 2022, we believe global oil demand will have exceeded pumping capability for the first time in history. Just as no one agreed with our assessment of an emerging energy crisis this time last year, almost no one agrees us today either. Instead, conventional wisdom strongly believes OPEC spare capacity will be returned, eventually throwing the market into huge surplus in 2022.

When we say demand will exceed pumping capability, what do we mean and why is this so unprecedented? While it is true that demand has exceeded supply many times in the past, it has never -- according to our models -- exceeded pumping capability. What is the difference? Supply is the amount of crude produced and sold into the market. Pumping capability, on the other hand, is a more subjective term that refers to total supply that could, in principle, be produced quickly with minimal additional capital spending. Therefore, while demand has exceeded actual production – most recently in 2006/2008 and 2020 – there has always been the availability of additional spare capacity. This will not be the case as soon as the end of next year. The consequences could be dire.

Even during the twin oil crises of the 1970s, when OECD countries were forced to implement gasoline rationing, demand never actually exceeded pumping capability. OPEC production fell in 1973 in retaliation for the United States' involvement in the Yom Kippur War and again in 1979 following the Iranian Revolution. Demand exceeded supply in both cases and prices spiked, however pumping capability was unchanged – production had been curtailed far below pumping capability. Our models estimate that pumping capability exceeded demand by nearly 5 mm b/d following both the first and second oil crises.

More recently, oil markets were in a severe deficit between the summer of 2007 and 2008, caused primarily by disappointing non-OPEC production trends. Demand exceeded supply by approximately 500,000 b/d, causing inventories to fall and prices to surge from $55 to a record-setting $145 per barrel. However, even then OPEC maintained over 3 m b/d of spare capacity, according to the IEA.

Last year, COVID-19-related shutdowns led to a widespread reduction in crude demand. Inventories built and US shale producers actively shut-in as much production as possible. OPEC+ agreed to a nearly 8 mm b/d supply cut to help balance markets. Inventories built at first but then immediately drew, as demand rebounded while production remained subdued. Prices rose as the market realized it was in near-term deficit by as much as 1.5 m b/d. Even though the market was in severe deficit, global demand did not exceed pumping capability. US shut-in production could quickly be reinstated and OPEC+ maintained ample spare capacity. We estimate that even as inventories were drawing more than 1 m b/d, pumping capacity exceeded demand by as much as 5 m b/d.

By the end of next year, our models tell us this cushion will have eroded completely. To understand why, let us explain the current crude balances and our projections for 2022. According to International Energy Agency's (IEA) Oil Market Report (OMR), 4Q21 demand will average 98.9 mm b/d. Although this is an incredible 5 m b/d above last year's level, it remains 1.7 m b/d below the pre-COVID 4Q19 level. Global liquids production averaged 96 mm b/d in September, pointing to a market nearly 3 mm b/d in deficit. OPEC+ production reached 42.2 mm b/d in September and based upon their current agreement (last reconfirmed on November 3rd), production quotas will grow by 400,000 b/d per month. The IEA estimates that OPEC+ sustainable capacity – what we are calling pumping capability – totals 50.1 mm b/d, nearly 8 mm b/d higher than current production.

Given these figures, why do we believe demand will exceed global pumping capacity by the end of 2022? The primary reason is demand.

We have long written that emerging market demand has been much stronger than investors (and the IEA) expect. Few energy analysts seem to make this adjustment and their models end up chronically underestimating non-OECD demand. Every demand dip over the last 20 years has been less severe, and rebounded more quickly, than forecast. This was true following the 2008 global financial crisis, when oil demand exceeded its pre-crisis high within a mere 18 months. It was true following the European debt crisis, when global demand actually grew by 2.5 mm b/d despite EU demand falling by 700,000 b/d. And it was true during COVID-19.

As recently as last fall, analysts predicted demand might never again reach 2019 levels; once again these estimates have proven too pessimistic. While total global demand has not yet surpassed 2019 highs due to ongoing travel restrictions, several countries have exceeded their pre-COVID levels. The three largest sources of demand, China, India and the United

States, all registered record monthly demand in 2021. Moreover, widespread global travel restrictions mean demand reached record levels in these countries despite jet fuel demand still well below pre-COVID readings. The US dropped its remaining travel restrictions on November 8th, and we expect demand will surge as other countries follow suit.

The IEA expects global demand to reach 99.6 mm b/d next year, with the highest reading in Q4 at 100.2 mm b/d. Our models tell us the IEA is again dramatically underestimating demand by as much as 1.5 m b/d. We carefully monitor so-called "missing barrels" which occur when the IEA's own figures do not balance. For example, the change in inventory should equal the difference between supply and demand but many times this is not the case. We euphemistically refer to "missing" barrels as those that were allegedly produced but neither consumed nor stored in inventory. Either consumption is understated or production is overstated -- inventories are usually accurate. Our S-curve models suggest demand is the problem. Based upon the "missing barrels," we believe demand is currently running at least 500,000 b/d ahead of expectations and that this will continue into 2022.

Furthermore, the ongoing natural gas crisis will dramatically increase oil demand by another 500,000 b/d as utilities switch from gas to oil wherever possilbe. The IEA has already started accounting for this by revising 2022 demand higher across the first three quarters by 300,000 b/d on average. However, they have offset much of this increase with a huge 400,000 b/d downward revision to 4Q22 demand without offering any explanation. This is a technique we have observed in the past: the IEA will revise near-term demand higher as actual results come in while revising longer-term demand lower, keeping the full year projection unchanged.

This year is no different. Over the last 90 days, the IEA has revised first half 2021 higher by 300,000 b/d as actual results have come in ahead of expectations, and offset the increase by lowering second half demand by the same amount. We believe this is a prime example of "kicking the can down the road" and will result in a flurry of upward demand revisions both this year and next.

Taken together, these two revisions will likely leave 2022 demand much higher than expectations, notably in Q4. Instead of averaging 99.6 mm b/d, we believe 2022 demand could exceed 100.6 m b/d – an all-time high. Q4 demand could reach 101.6 m b/d.

Turning to supply, the only source of non-OPEC+ growth over the past decade -- the US – remains stubbornly 1.8 m b/d below its late 2019 peak and does not appear to be improving. Over the past eight months, US production has grown by only 7,000 b/d per month compared with 150,000 b/d per month on average in 2012-2014 and 2017-2019. Higher prices have not led to materially higher drilling budgets for 2021 or 2022 and the oil rig count remains depressed at 450 rigs – up 280 rigs from the bottom but still half the pre-COVID level.

It is no surprise the US is not seeing a strong rebound in production: the shales are suffering from depletion, a topic we first discussed in late 2019. Every shale basin except the Permian is experiencing outright decline. Over the last 12 months, the Eagle Ford and Bakken have declined by 4,000 b/d per month on average compared with monthly growth of 20,000 b/d as recently as late 2018. The Permian is the least developed of the major basins and we have often predicted it will still be able to grow, albeit at a much lower rate than in years past. Over the past 12 months, Permian growth averaged 35,000 b/d per month – 65% less than it grew in 2018. The remaining shale basins are declining by a total of 13,000 b/d per month compared with 25,000 b/d monthly growth a few years ago. Taken together, shale production is only growing 14,000 b/d per month compared with 160,000 b/d in late 2018 – a slowdown of 90%.

Even this meager growth is being distorted and will likely drop in the coming months. The distortion is being caused by the harvesting of drilled-but-uncompleted wells (DUCs). During last year's oil collapse, companies elected to postpone completing a well where possilbe to save on capital expenditures (completion is half of total well costs). This caused the DUC inventory to swell to unprecedented levels. As prices recovered, completing the DUCs generated extremely high incremental returns on investment given the drilling capital was already "sunk." Since June 2020, twice the number of wells were completed than drilled in the Eagle Ford and Bakken. In the Permian, 66% more wells were completed than drilled. Across all the shale basins, 60% more wells were completed than drilled. Our neural network estimates that without the DUCs, shale production would be 800,000 b/d lower than it is presently and that every basin, including the Permian, would be in sustained decline.

Clearly this trend cannot persist indefinitely. A certain number of DUCs are required for normal shale development. Historically, the industry operated with a DUC inventory equivalent to five months of drilling activity. Using this metric, "excess" DUC inventory (i.e., over and above five months of drilling) peaked at 5,000 locations across the Eagle Ford, Bakken, and Permian in June 2020. As of September 2021, the "excess" inventory had fallen to 1,300 locations – a decline of 75%. At the current rate, we estimate DUC inventory will reach the equivalent of five months of drilling activity by mid-2022, at which point it will be difficult to draw down DUC inventory any further. For shale production to grow, drilling activity will need to increase dramatically – unlikely given the ESG capital pressures faced by publicly traded oil companies.

Furthermore, depletion problems across the shales persist. Our neural network initially pointed to the fact that once a basin has developed 50% of its Tier 1 wells, total production begins to plateau and then decline. We used this to correctly predict the Eagle Ford and Bakken would peak in late 2019. At the time, we stated that Permian production would still be able to grow for the next few years given only 35% of Tier 1 wells had been developed. Our models now tell us that 45% of Tier 1 Permian wells have been developed, implying we are much closer to its inevitable plateau and decline as well. By the end of 2022, we believe the final US shale basin will cease to growth.

The IEA currently estimates US production will grow by 1 mm b/d in 2022 and by 900,000 b/d from the last monthly reading, but our models suggest this is too optimistic. We admit that we underestimated US growth for most of 2021, but this was largely due to accelerated DUC harvesting. Given the vast majority of excess DUC inventory has now been completed, we believe our initial predictions will take hold starting in mid-2022. Instead of growing by 900,000 b/d from here, we believe US production might only grow 300,000 b/d.

It is unlikely that non-OPEC+ production outside the US will be able to grow next year. This bloc of production has been challenged for years and has chronically disappointed. A dearth of new discoveries has translated into less growth for more than a decade. Since December 2020, the IEA has been forced to revise 1H21 production dramatically lower from this group as actual results have come in far below expectations. Over the last ten months, the IEA has revised 1H21 non-OPEC+ ex US production lower by 800,000 b/d, led mostly by Brazil and Norway. However, just as with demand, the IEA has taken to offsetting revisions in the near months with equal but opposite revisions to later months. At the same time as the IEA revised 1H21 production lower by 800,000 b/d, they revised 2H21 production higher by 200,000 b/d leaving their full-year projection lower by less than 300,000 b/d.

The IEA remains equally optimistic for non-OPEC+ ex US growth in 2022. In their most recent report, the IEA projects this group will grow production next year by 900,000 b/d. In aggregate, they believe non-OPEC+ ex US will average 30.6 mm b/d next year whereas our models predict this could be as low as 30 mm b/d.

After making the adjustments discussed above, we believe demand will exceed pumping capacity by 4Q22. The IEA believes 4Q22 demand will reach 100.2 mm b/d, while US production will average 17.7 mm b/d, and non-OPEC+ ex US will average 30.9 mm b/d. OPEC+ NGLs are expected to average 7.9 mm b/d, leaving the call on OPEC+ crude at 43.7 mm b/d – 1.6 mm b/d higher than today and well within their pumping capability.

Our models suggest 4Q22 demand will reach 101.6 m b/d while US production may only average 17 m b/d. Assuming non-OPEC+ ex US pumps at 30.0 m b/d in 4Q22 and OPEC+ NGLs average 7.7 mm b/d, the call on OPEC+ crude jumps to 46.9 mm b/d or 4.7 m b/d above current rates.

TABLE 1 Crude Balances

	4Q2022		
	IEA Est	***Adj.***	***G&R Est.***
Demand	100.2		
Missing Barrels		0.6	
2H22 Revision		0.7	
Pro Forma Demand	**100.2**		**101.6**
Production			
US Production	17.7	(0.7)	17.0
Non-OPEC+ ex US	30.9	(0.9)	30.0
OPEC+ NGLs	7.9		7.7
Total	**56.5**		**54.7**
Call on OPEC+ Crud	**43.7**		**46.9**
Current OPEC+ Crud	42.2		42.2
Spare Capacity	7.9	(3.2)	4.7
Pumping Capability	**50.0**		**46.9**

Source: G&R Estimates.

Can OPEC+ meet this increased demand? We believe it will be difficult. The only countries with material remaining spare capacity are Saudi Arabia, UAE, Kuwait, Iran, and Russia. Iraq has spare capacity, but given the security considerations, it is extremely unlikely production will grow in the near or medium term. We have discussed our skepticism regarding Saudi spare capacity in the past and intend to revisit the important topic next quarter. Ultimately, we believe Saudi Arabia can produce between 10 and 10.5 mm b/d – well below the stated 12.2 m b/d capacity. Saudi has only produced above 10 mm b/d on two occasions and both times it was for only a brief period and the fields had to subsequently be rested. Assuming Saudi has pumping capacity for 10.5 m b/d (a big if), we believe total OPEC+ crude capacity to be 46.9 m b/d – not enough to meet global demand by 4Q22.

Twelve months ago, few people listened when we predicted an energy crisis was imminent. Now, our models suggest that we could be entering a new period in the history of oil – a period without any excess global pumping capability. The ramifications could be huge. Investors today have hardly any exposure to oil producing companies at all. After having averaged 10-15% of the S&P 500 for decades (and reaching a maximum of 30%), energy stocks today stand at less than 3% of index. Just as few investors saw the energy crisis, fewer believe an oil crisis is looming. Position yourselves accordingly.

Natural Gas: From the Cheapest Energy in History to the Most Expensive in 12 Months

Nobody expected the emerging energy crisis would be led by natural gas. Over the past decade, surging US shale production pressured prices relentlessly downward. Henry Hub natural gas prices peaked in July 2008 at $13.58 per mmbtu. By June of 2020, amid the COVID-19 pandemonium, prices had fallen to $1.48, a decline of almost 90%. Natural gas was also extremely out of favor relative to other energy sources, especially oil. As late as the final two weeks of 2008, oil prices traded on average at $37 per barrel and Henry Hub gas prices averaged $5.80 per mmbtu -- a 6:1 ratio very much in line with the btu content of both oil and gas. By the beginning of 2020, just before the panic that briefly took oil negative, crude oil prices and natural gas traded at a ratio of 30:1 ($37 per barrel, $1.90 per mmbtu), implying the btu content in gas was trading at an 80% discount to the btu content in oil. Apart from the moment when WTI turned negative, last year's natural gas low represented the cheapest price for a fossil fuel per btu over the last 25 years – and possibly the lowest real price in history. Given its low price and unpopularity, it came as a complete surprise to everyone that natural gas would be the first energy market to fall into crisis. We turned bullish on natural gas in the fall of 2019 and dramatically increased our exposure as gas prices made their lows last summer. Despite that position, we believed oil would be the first market to fall into crisis, with gas following later. Instead, just the opposite has occurred.

In the span of only 18 months, natural gas went from setting the lowest energy price on a btu basis in 25 years to setting the highest price in history. This past fall, Asian liquified natural gas (LNG) prices regularly exceeded $35 per mmbtu, equivalent to a crude price of $210 per barrel (while some extremely short-term weather disruptions may have led to historically higher prices temporarily, we believe $35 per mmbtu is the highest sustained energy price in history). It is now widely accepted that much of Europe and Asia is engulfed in a full-blown energy crisis with cascading natural gas shortages at the core.

How did the natural gas market turn so abruptly? Stepping back, the fundamental underlying driver has been years of stronger than expected emerging market demand. In the more immediate term, today's natural gas crisis is the result of a confluence of seemingly unrelated events across three continents, again proving how interconnected modern energy markets have become.

The current natural gas crisis originated in Russia in late 2020. A much colder-than-normal winter left Russian natural gas stockpiles well below average by spring 2021. Winter-ending inventories normally average 1.2 tcf, but this year the cold winter drew stockpiles down to a mere 400 bcf – the lowest reading in memory. Typically, Russia builds inventories over the summer, reaching 2.6 tcf on average by November 1st. This summer, the Russian authorities announced they would inject at a faster rate to erase the deficit left by the prior cold winter. We estimate that instead of injecting 6.5 bcf/d on average between April 1st and November 1st, Russia would have to inject nearly 10.5 bcf/d to replenish inventories to average levels ahead of winter.

Russian natural gas production declined in 2020 and recent data indicates little in the way of a rebound. We also believe LNG exports, driven by major expansions in the Yamal Peninsula LNG projects, would not be curtailed to help the refill domestic inventories. The only remaining option to replenish domestic Russian inventories would be to curtail pipeline exports to Europe, which Russia did throughout the late summer and autumn.

The UK and Europe meanwhile also endured a colder-than-normal winter with natural gas inventories below normal going into the spring injection season. Making matters worse, wind patterns in the UK (and to a lesser extent across Europe) fell woefully below expectations, resulting in much less wind power than anticipated – an inherent limitation to wind power we have discussed at length in past letters. Given Europe's high carbon price, natural gas (instead of coal) was used to backfill the lower electricity generation, taking inventories down dramatically. A hotter-than-normal summer across the UK and Europe resulted in higher-than-expected air conditioning demand putting even more strain on an already tight gas market.

With the UK and Europe unable to increase gas imports from Russia, utility buyers turned desperately to seaborne LNG to replenish inventories. Given how loose LNG markets had been only a few months before, few buyers expected any difficulty accessing spot cargos. Unfortunately, Asian demand bounced back from its COVID-19 lows much more quickly than anyone thought possible. Power shortages were reported throughout China as industrial demand surged more than utility buyers had expected. Beijing instructed fuel buyers to go and acquire any available energy in September to avert further shutdowns. At the same time, Brazilian rainfall was much lower than expected, resulting in less hydroelectricity than normal, further increasing Brazilian LNG demand to make up the shortfall.

Preliminary data suggests that European-bound LNG imports fell over the summer by 18% year-on-year as spot cargos were impossible to find. Panic took hold in September once commercial and utility buyers realized there was no way to replenish inventories ahead of the winter heating season. Prices rallied to over $30 per mmbtu across the UK, Europe and most of Asia and remain above these levels today.

Although this exact sequence of events was impossible to predict, the underlying trends in global natural gas have been quietly leading to this inevitable outcome for years. The most important of these trends is demand. Beginning in 2013, we wrote about the relationship between a country's wealth and its demand for natural gas. When a country is poor, it must burn the cheapest energy available: coal. Compared with coal, natural gas is a much cleaner fuel – generating much less smog and CO2 – however, it is expensive. Not only is gas more expensive per mmbtu, but the infrastructure needed to handle a gas instead of a solid is dramatically higher. Therefore, poorer countries tend to use less natural gas as a percent of their energy mix. OECD countries generate 12% of their primary energy from coal compared with 37% for non-OECD countries.

As a country gets richer, its citizens demand a better quality of life – and air quality is extremely important. For example, in a recent survey of Chinese citizens, the top five concerns were dominated by issues of environmental degradation. In 2015, demonstrations erupted across China demanding cleaner air as hundreds of millions in and around major urban areas were subjected to endless smog and haze. Shortly thereafter, the Chinese Communist Party (CCP) announced a plan to increase natural gas to 15% of its energy mix by 2030 from only 5% in 2015.

We first identified these trends back in 2010 and used the relationship between per capita wealth and natural gas share of the energy mix to build a global gas demand model projecting robust demand far greater than consensus. At the time, prevailing wisdom held that projected large increases in Qatar export capacity could not be absorbed by world markets and that LNG prices would be driven to sub $1 per mmbtu -- LNG's marginal cost. This bearish argument took global planned import capacity, which was projected to grow far more slowly than LNG supply, as a proxy for demand. We argued instead that rising incomes, coupled with global growth, would be the factors driving consumption and that import infrastructure would grow to meet demand, not the other way around.

We have updated our models several times since then. Every time we do, our models become even more bullish. Between 2010 and 2020, Chinese gas demand tripled – far more than anyone believed possible. As China's per capita wealth increased, Chinese LNG imports went up seven-fold as production and pipeline imports were unable to meet the increased demand resulting from the desire to switch away from burning coal. Last year, gas made up 8% of China's energy mix – up from 4% in 2010 -- and is on track to reach 15% by 2030. Earlier this year China replaced Japan as the largest LNG importer for the first time ever.

Going forward, LNG demand is again set to surge much more than analysts believe possible. Our base case assumes Chinese real GDP grows at 4% per annum while primary energy demand grows at 2%. If natural gas reaches 15% of total energy by 2030, consumption will more than double from 33 bcf/d today to 75 bcf/d by the end of the decade. If domestic production grows 5% per year and pipeline imports double again from here, LNG demand must grow nearly four-fold from 9.5 bcf/d in 2020 to 36 bcf/d by 2030. This alone would consume all the planned new LNG export capacity as wells as a portion of all proposed projects.

China is not the only country going through this phenomenon. Emerging markets around the world are moving as quickly as possible to LNG to improve air quality and reduce carbon emissions, just as our wealth models predicted. Global LNG demand growth outside of

China and Japan (where demand has been heavily impacted by shut-down nuclear reactors) has exploded. Between 2010 and 2015, the rest of the world consumed approximately 19 bcf/d and exhibited no growth. Between 2015 and 2020, demand grew 50%, going from 19 bcf/d to 29 bcf/d in only five years. Going forward, these trends will continue resulting in ever-stronger global LNG demand.

Many energy analysts still do not properly understand these trends. For example, Wood Mackenzie recently published a note discussing Chinese LNG demand. In their report, they acknowledge that demand will grow, but upon closer inspection their estimates for 2030 are less than half what our models predict. If analysts had properly understood natural gas's strong underlying demand factors, today's crisis might not have been so unexpected.

Where will the supply come from to meet new LNG demand? Owing to their large upfront capital costs, historically LNG projects have been limited to the super-majors. Unfortunately, ESG pressures have left these companies unable to commit to new projects and they are now being forced to divest existing ones (as you read in "The Incredible Shrinking Majors Part II"). Natural gas production has been harder to come by as companies around the world continue to curtail capital spending. Leaving aside the US, which we will discuss in a moment, two-thirds of gas-producing countries, representing nearly 40% of global production, have seen their volumes decline over the last three years. These trends will likely get worse.

Another source of LNG export growth has been the US which, since 2015, has represented more than half of global natural gas production growth and 40% of LNG supply growth. In that time, US LNG exports grew by 6 bcf/d and the feed gas for these exports was easily sourced--domestic production grew nearly 17 bcf/d over the same period. There is currently another 5 bcf/d of US LNG export capacity fully permitted and under construction and another 50 bcf/d proposed. Yet, US production peaked in November 2019 at 97.2 bcf/d and remains 2 bcf/d lower today. Over that time, growth in the Marcellus, Permian, and Haynesville has not been enough to offset declines in the rest of the country. Recent production trends suggest that growth may be coming back modestly, but it remains early, and our modelling continues to suggest production growth disappointments emerging in the next several years. Since November 2019, Marcellus production growth has averaged 26 mmcf/d per month, compared with 300 mmcf/d per month on average between 2017-2019 – a decline of 90%.

In our next quarterly letter, we will revisit drilling productivity and production trends across the shale basins and discuss the implications for future gas balances. Any changes to US trends will have a major impact on the global gas market going forward.

In the near term, gas prices will be driven by the weather. While this is true every winter, it is especially the case now. Inventories in the UK and Europe were only 50-60% full by the end of summer, the lowest level in years and far below the 80% from the same time last year. Once Russia releases new data, we will see if they were successful in rebuilding inventories, although our models suggest they came up short. Inventories in the US went from nearly 10% above average at the start of the year to as low as 8% below average by September. While mild weather and higher production has helped rebuild inventories, they remain 4% below average going into the winter heating season. Asian inventories are also at multi-year lows.

As the winter progresses, any colder-than-normal weather globally will likely incite a panic-buying surge that will drive prices much higher. We remain extremely bullish on global natural gas given the extremely tight fundamentals. We cannot recall a time where all the major gas consumers were so under-supplied going into winter. At the same time, the longer-term fundamentals – accelerating non-OECD demand – are extremely bullish. We expect the current "crisis" will be with us significantly longer than most investors expect.

A Financial Player Emerges in Uranium

Both spot and term uranium rallied sharply during Q3, reaching the highest level in five years. Prices have now reached $45 per pound, an advance of 70% for the year. We spoke at Alpine Macro's inaugural investment conference this October, focusing on the history of energy and the importance of "energetics" to global economic growth. We discussed how the aggressive adoption of nuclear-generated power would be an ideal solution to our current problems: CO2 emissions would be significantly reduced while global economic growth, driven by nuclear power's extremely high energetics, would show significant acceleration. We have made a video of our speech available on our website (click here).

Energetics measures the ratio of energy return on energy invested (EROEI), or how much energy is required to generate usable power. For most of human history, food, wood, and animal labor provided almost all of society's energy. The extremely low EROEI inherent in these sources barely covered survival, let alone economic growth. Confirming the extremely low EROEI of these energy sources, population growth averaged only 0.04% between AD 1 and 1650 and real GDP growth was comparable—in other words, there was little to no growth. In the early seventeenth century, coal began supplanting wood after much of England's forests had been consumed for its energy. Coal generates a much higher EROEI than wood and so surplus energy – i.e., the energy produced above what is needed for human survival -- grew sharply. Post 1650, population, and real per capita GDP surged. After having taken 1600 years to double, wealth grew by an incredible factor of 55 over the next 400 years.

The first chapter of energy history (AD 1 to 1650) was long and static. It was a time of short life expectancy and very little economic growth. The second chapter (1650 to today) was one of rapid growth and progress, all brought about by the hugely superior energetics of burning fossil fuels. We are now on the verge of the third chapter. Policy makers have insisted on a move away from carbon emissions. Unfortunately, when properly buffered for intermittency, wind and solar suffer an EROEI as low as food, wood, and animal labor. Nuclear power on the other hand has an EROEI that is three times higher than coal, natural gas and crude. Moving from fossil fuels to nuclear power would be as important a step change as going from food and wood to fossil fuels was 400 years ago; a change that brought about not only the Enlightenment, but the prosperous world that we live in today. What could lie ahead this time if society makes the right choice?

Turning back to the current day, few investors expected this latest uranium rally. As recently as June, uranium was flat year-on-year. Prices began to surge in August and the rally has persisted into September and October. Responding to higher prices, the related equities rallied sharply with Cameco and Kazatomprom advancing 60% and 90% since August.

In the near term, the recent rally was triggered by a new financial participant: the Sprott Physical Uranium Trust. We believe its emergence is more a symptom of an already extremely tight physical market and not the underlying cause of this nascent bull market. The distinction is extremely important.

As early as 3Q18, we discussed how new players would emerge in uranium markets: financial buyers. In July 2021, Sprott announced their intention to acquire the Uranium Participation Corporation; in August they successfully completed the transaction. (Full disclosure: we owned Uranium Participation Corp and currently own the Sprott Physical Uranium Trust.) The Uranium Participation Corporation was a publicly traded, closed-end vehicle that would buy and hold physical uranium. Some compared the company to the SPDR Gold Shares (GLD), but this comparison was misleading. In the case of GLD, the sponsor buys and sells gold in response to investor demand. When investors buy GLD, new shares are issued and gold is bought. When investors sell GLD, gold is sold, and the proceeds used to retire shares. Since the Sprott Physical Uranium Trust is closed-end, purchased uranium is theoretically never liquidated. If investors sell shares, the Trust might trade at a discount to its net asset value but shares do not have to be retired and so physical uranium sales do not take place. The physical uranium purchased by the trust is taken off the market permanently.

Sprott also restructured the company, allowing for "at-the-money" offerings to raise new capital. It became much easier for Sprott to quickly take advantage of increased uranium investment demand.

Sprott announced their first $300 mm at-the-money offering on August 17th 2021. At the prevailing uranium price of $32, the deal represented just under 10 mm pounds of uranium or approximately 5% of annual global demand. The deal pushed spot uranium prices slightly higher, but went largely unnoticed by the broader community. On September 14th 2021, Sprott announced another $1 bn at-the-money offering, representing another 15% of global demand. Prices surged in a matter of weeks and the investment community finally took notice. Sprott stopped buying uranium in late September, and prices fell back somewhat. More recently, they have resumed their purchases and prices have again rallied.

Uranium bears argue the nascent bull market has been manufactured by Sprott: once they stop buying, prices will fall. We disagree. Our rationale is simple: the physical uranium market slipped into severe deficit two years ago. However, uranium prices remained depressed because of large inventory stockpiles built up after the 2011 Fukushima nuclear accident. Japanese utilities continued to take delivery of uranium, even though their reactors were off-line. Given today's uranium market deficit, we believe most of these stockpiles have been consumed, even though many still believed some post-Fukushima-related inventory remained as we entered 2021.

Given that spot uranium prices, even at $50 per pound, are still far below what is needed to bring on new production, and with the market's large deficit, it was only a matter of time before a shrewd financial player would attempt to buy any remaining post-Fukushima inventory. That's just what Sprott did.

The uranium market slipped into deficit in 2019 and that deficit accelerated into 2020 and 2021. We estimate that demand is running nearly 35 mm pounds above primary supply, on a total market of 190 mm pounds. The deficit has been met by producer and utility inventories which have drawn down dramatically. Cameco's inventories ended Q3 at only 8.5 mm pounds, compared with 14.4 mm pounds at the same time last year and 32.9 mm pounds in 2017. Kazatomprom's inventories have trended sharply lower as well. Utility inventory is more difficult to measure but all indications point to a sharp drawdown.

Furthermore, low prices have led to a reduction in mine development. Currently, uranium mining is basically a duopoly, with Cameco and Kazatomprom producing virtually all mine supply. Both producers have shut in production over the past several years and neither is spending any material capital on remaining operations. In the case of Kazatomprom, capital spending in future development has fallen significantly. Almost all Kazatomprom's uranium is produced using the in-situ leach mining method and ongoing development capital is necessary to replace depleting fields.

The physical uranium market is notoriously opaque. How can we be sure it is actually as tight as our models suggest? One extremely important sign is how difficult it has been for both Cameco and Sprott to secure physical volumes. When Cameco announced they were temporarily closing MacArthur River in 2018, they stated they would look to the spot market to meet long-term contracted obligations. They stated emphatically they did not intend to draw down operating inventories. Given the challenges in securing spot volumes, Cameco's inventories are now 70% lower than three years ago. More recently, Sprott has had a very difficult time securing spot volumes following its latest offering. This suggests the "readily available" stockpiles are rapidly shrinking.

Also, we believe it is instructive to compare the emergence of financial players in the uranium market versus events in the silver market earlier this year. In January 2021, the Reddit crowd, acting on rumors of a large short position in the silver market -- a rumor that has persisted for years -- attempted to engineer a silver market "squeeze." Silver rallied 8% in one-day making significant headlines. However, the physical market was not as tight as financial players hoped and the short squeeze was quickly abandoned. Within one week, silver was lower than where is started, and the financial players were quickly vanquished by well-funded commercial participants.

In the case of the uranium market, Sprott announced their $1.3 bn at-the-money offerings in September. Two months later, spot and term uranium remain 70% higher and Sprott has been unable to source all the necessary material.

This is an extremely tight physical market; Sprott recognized how tight it had become and acted accordingly. They did not cause the physical tightness but rather took advantage of it.

As world leaders meet in Glasgow this weekend, nuclear power is being discussed in earnest for the first time in a decade. Our investment has always been predicated on non-OECD demand growth. That is still the case but we are extremely encouraged to see OECD policy makers discuss openly how nuclear power is essential for any serious de-carbonization plan (something we have argued for years). The UK recently announced that nuclear power is essential to meet their 2050 net-zero policy. France has announced €1 bn in spending on small modular reactors and Japan's LDP party has now turned extremely pro-nuclear. Incredibly, even Germany has talked about revising its anti-nuclear stance. Germany has established itself as the most anti-nuclear western country over the past decade and it has now decommissioned almost its entire fleet of 26 reactors. The potential change in Germany's anti-nuclear stance makes us even more convinced nuclear sentiment is shifting.

Perhaps energy history's third chapter will be the most vibrant yet, driven by nuclear power's superior energetics.

Tightness in Grain Markets

"Food Supply Chains Are Buckling as World Runs Short of Workers" Bloomberg, September 2nd 2021

"Ruined Brazil Harvest Sparks Food Inflation Everywhere" Bloomberg September 28th 2021

The world is slowly slipping into an agricultural crisis. Demand for grain remains strong, while certain supply trends that have been in place for 40 years are about to reverse. Reflecting these trends, grain prices have surged over the last 12 months. Although copper captured investors' attention this spring as it made a new all-time high, corn and soy came within 5% of their 2012 drought-related highs as well.

Between 1980 and 2000, global grain consumption grew by 1.3% per year. Since then, driven by emerging market demand, grain consumption growth has ratcheted up to 2.3% annually – an acceleration of 75%.

As an emerging market gets richer, demand for most commodities rises rapidly, be it oil, natural gas, grain, etc. No market is more prone to this phenomenon than agriculture. The desire to consume more protein and less starch rises rapidly as a country progresses from poor to middle income to wealthy.

In our next quarterly letter, we will discuss the relationship between historical protein consumption and wealth going back 100 years – including in Japan through the 1960s when per capita GDP was less than $500.

Also in our next quarterly letter, we will discuss various weather issues affecting the 2022-2023 crop year. Although most journalists and investment professionals believe global warming has negatively impacted global growing conditions, our analysis suggests the opposite. We believe that over the last 40 years, warming trends have produced consistently better and better growing conditions as seasons have lengthened and crop-killing frosts have diminished. Now that we are likely entering a global cooling phase due to decreased sunspot activity, growing conditions may become more challenged. These conditions may already be at work.

Grain prices were weak in Q3, driven mostly by technical trading and less by any significant change to the underlying fundamentals. Corn fell 25% during the quarter while soybeans fell 13% and wheat advanced 8%.

Spot corn peaked at $7.75 per bushel back in May 2021, only 5% below its all-time high, set during a severe North American drought in 2012.

In the May 2021 World Agricultural Supply Demand Estimate (WASDE) report, the United States Department of Agriculture (USDA) projected corn 2021 ending stocks (inventories just before the current harvest begins) of only 1.1 bn bushels. Although not quite a record low, inventories were projected to have fallen low enough to put severe upward pressure on price. As summer progressed, corn prices eased as the new corn crop began to be harvested in July and inventories began to rebuild. The same phenomenon was at work in a very tight soybean market. Soybean prices also peaked in May and began to ease as summer progressed and the new harvest began in September.

Although grain prices pulled back during Q3, 2022 is set for another spike higher. In our last letter we wrote about our recent development of an artificial neural network to help predict corn yields (with a soybean neural network to follow).

Estimating crop yields is both critical in predicting grain production and fiendishly difficult to get correct. Given our success in building a neural network to deal with difficult questions in shale productivity, we decided to try the same approach to corn yields.

We set out to develop a neural network that would explicitly incorporate the vagaries of weather. This model would start out making a wide prediction that would narrow over time as actual weather was updated throughout the growing season. Our estimate for crop yields would evolve in real time.

In our last quarterly letter, we outlined our initial prediction for 2021 corn yields, but warned that further updating was needed as more weather data came in.

We wanted to make sure our models were not "over-fitting" the data -- coming up with spurious relationships instead of finding true causal links.

Our first attempt at predicting the 2021 US crop yield turned out to be quite interesting. Because of near drought conditions across large swaths of the corn belt, we strongly believed the USDA's 2021 record yield estimate of 179.5 bushels per acre would disappoint. Based upon crop conditions that existed in July, our neural network projected corn yields would fall between 169 (the 2019 season) and 172 (the 2020 season) bushels per acre – well below the USDA estimates.

No sooner than we had published our letter, the USDA slashed their yield estimate to 174.6 in their August WASDE report causing prices to rally. The USDA was forced to recognize the very challenging growing conditions in Iowa, Minnesota and South Dakota. As a result, the USDA lowered the 2021 corn harvest estimate by almost 425 mm bushels.

Offsetting this revision, the USDA also reduced domestic corn usage and export demand by almost 200 mm bushels. By the end of August, the USDA forecast the 2021-2022 corn ending stocks would only reach 1.24 bn bushels -- only marginally higher than last year's extremely low levels.

In their last two monthly reports (September and October), the USDA has increased yield assumption higher back to 176.5m, which has raised the 2021 crop size up by 270 mm bushels and brought back the 2021-2022 ending stock estimate to 1.5 bn bushels.

Is this 176.5 bushels per acre estimate anywhere near a realistic corn yield for the 2021 corn crop? Because of the extreme dry conditions that existed in large swaths of the northern and western corn belts, we believe this year's estimate of 176.5, which we should point out ties the record corn yield of both 2018 and 2019, is too high. Turning to our neural network, it too is telling us that the USDA is still overestimating yields. Based on crop growing conditions up to mid-October, our neural networks say that we should expect corn yields to come in between 172 and 174 bushel per acre, below the USDA estimate. If corn yields were to fall to these levels, this would drop the 2021-2022 corn ending stock to dangerously low levels. Any weather related problems that emerge in next year's harvest would send corn prices skyrocketing.

In soybeans, the situation is not as tight, but similar to corn: any disappointment in the 2022 crop could put extreme upward pressure on price. The USDA is expecting soybean yields to reach a near record 51.5 bushels per acre. Even with near record yields, soybean ending stocks are only expected to rise from this year's 185 mm bushels (extremely low) to 320 mm bushels (near average) next year.

Most of the soybean regions experienced much better growing conditions than corn, so we do not expect a large yield disappointment. That is ultimately a good thing since any disappointment would throw the soybean market into turmoil given extremely low carry- over inventories from last year. Once our soybean neural network is complete, we will be able to make much more accurate predictions for soy as well as corn yields.

Strong demand, low inventories and the rising probability of disruptive weather patterns all leave agriculture markets primed for a sharp rally.

The rapidly evolving energy crisis has spilled over into global fertilizer markets, with bullish consequences. We have maintained significant exposure to fertilizer producers, and will continue to do so. Fertilizers have been the best performing commodities over the last nine months. Urea (solid nitrogen) doubled, while phosphate is up 70% and potash (the fertilizer every analyst loves to hate) is up 160%.

Fertilizer production (especially nitrogen and phosphate) is very energy intensive. China has already restricted production of both fertilizers to help conserve energy and has announced export restrictions. The ramifications are huge: China produces half of global urea and nearly 60% of global phosphate-based fertilizers making it the world's largest exporter.

In the near term, these restrictions will put huge upward pressure on fertilizer prices. Over the medium term, less available fertilizer will negatively impact crop yields leading to higher grain prices as well.

Over the last 30 years, global crop yields have surged, driven in part by much greater availability of fertilizers. If fertilizer supply falls and prices rise, there will be a clear negative impact on crop yields as farmers are forced to reduce applications.

The global agricultural crisis has now entered its first phase. We continue to recommend investors maintain significant exposure to agricultural-related equities, with a special emphasis on fertilizer producers.

Copper Supply Continues to Disappoint

Copper supply and demand trends remain extremely positive. Demand continued to grow over the first seven months of 2021, though the sources of growth shifted somewhat. According to World Bureau of Metal Statistics (WBMS), last year demand grew by 3.5%, driven by a 13% surge in Chinese consumption offset by a COVID-related 6% drop in OECD countries. So far this year, demand has grown by 1.5%, driven by a rebound in OECD demand of 6% offset by 2% slowdown in Chinese consumption.

Copper mine supply continues to stagnate. New mine production is being offset by a depletion problem across the entire industry which is finally being recognized by the broader financial community. First Quantum ramped up production at their new flagship Cobre Panama mine beginning in late 2019, adding 320,000 tonnes of incremental mine supply. However, mine depletion elsewhere offset this increase, leaving total production flat. For the first six months of 2021, copper mine supply averaged 1.72 mm tonnes per month – unchanged from the same period five years ago.

An example of the depletion problem bedeviling aging copper mines is provided by Lundin Mining's Candelaria copper mine in Chile. After initially reducing their estimates for 2021 production by 15%, the company once again reduced 2022 and 2023 production estimates by a similar amount, surprising most analysts. Lower than expected grade and material handling challenges were given as reasons for the unexpected reduction.

Disappointments at the massive Oyu Tolgoi underground mine in Mongolia are now also expected to impact copper supply in 2022. The underground block-cave has already been significantly delayed because of unexpected geotechnical challenges. Originally slated to come online last year, first commercial production was initially delayed to 4Q22. Just recently, Rio Tinto PLC, the mine's operator, announced production would be pushed back yet again into 2023. Furthermore, capital expenditures were again increased by an additional $1 bn to complete underground mine development.

The Mongolian government currently owns 34% of the mine and could soon need to sign off on any additional investment. Oyu Tolgoi was expected to produce an additional 400,000 tonnes of additional copper from its underground operations and so any delays will tighten global mine supply even further.

One bright spot in mine supply has come from the large Kamoa/Kakula project in the Democratic Republic of Congo. The mine is now ramping up production and is expected to produce 200,000 tonnes of copper next year. This new supply could not come fast enough as we anticipate global depletion will remove roughly the same amount of production.

We remain very bullish on global copper. Demand remains strong while supply growth continues to be challenged. Reflecting the ongoing tightness, global inventories continue to fall. Copper inventories at the London Metal Exchange, the Shanghai Metal Exchange, and COMEX continue to draw. After peaking at over 600,000 combined tonnes in the first quarter of 2020, inventories now sit at only 270,000 tonnes, having fallen another 100,000 tonnes in the last quarter.

Although inventories are not at critically low levels, last seen in 2005-2006 immediately preceding copper's 150% price surge, they are getting close. Copper exchange inventories stand at less than four days of global consumption -- the third lowest reading in 30 years.

Copper markets are tight and likely getting tighter. Investors realize that copper is critical in electrifying large parts of the world, and analysts are beginning to realize the massive challenges of ongoing mine depletion. We believe the current weakness will prove temporary and continue to hold our copper investments.