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ON LNG, AI & SHALE SUPPLY: WE EXPECT THE TURN IN US GAS IS HERE

Table of Contents

We believe the North American natural gas market has reached a turning point. Significant shifts now taking place carry profound investment implications for the next twelve months. Our stance, which was cautious for almost a decade, turned bullish in the first quarter of 2020 when Henry Hub was at $1.43 per thousand cubic feet (mcf). In our 1Q20 letter, we wrote an essay titled "The Bull Market is Here," stating: "If production were ever to falter, a massive bull market would result. That moment has arrived." By summer 2022, Henry Hub gas surged more than six times, eventually reaching $9.68 per mcf as Russia's invasion of Ukraine spread fears of a global natural gas shortage. However, back-to-back warm winters and an ill-timed fire at a US LNG export facility overwhelmed the nascent bull market and gas retracted its entire move, selling off to within five cents of the June 2020 low. Although it may seem like a strange time to write a bullish lead essay on natural gas, it was equally strange to make a bullish call in the spring of 2020, immediately before gas rallied 553%.

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Natural Resource Investors

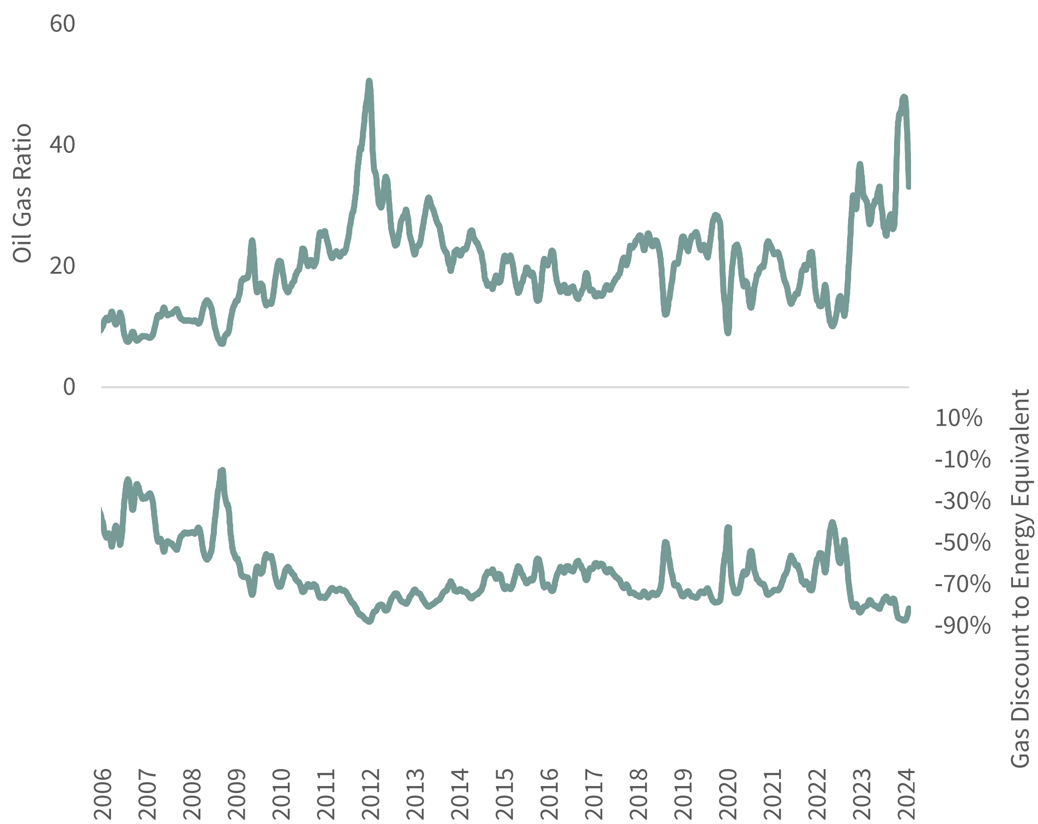
Our research suggests this rally could be even stronger.

Bearish sentiment reached a fevered peak in the first quarter of 2024. The 2023-2024 North American winter was 5% milder than normal – on par with the extremely warm winter of 2011-2012. A lack of heating demand pushed prices sharply lower. Gas for delivery at Henry Hub fell 30%, broke \$1.50 per mcf three times, and eventually bottomed at \$1.48 per mcf on March 26th. Over the past twenty-five years, Henry Hub only broke \$2.00 five times: in 2002, 2012, 2016, 2020, and earlier this year.

BY SOME MEASURES, NATURAL GAS PESSIMISM IN MARCH WAS THE WORST IN HISTORY. GAS BOTTOMED AMID A BROADER ENERGY SELL-OFF IN 2002, 2016, AND 2020. THIS YEAR, NATURAL GAS REACHED \$1.48 PER MCF, WITH OIL TRADING AT A HEALTHY \$81 PER BARREL.

By some measures, natural gas pessimism in March was the worst in history. Gas bottomed amid a broader energy sell-off in 2002, 2016, and 2020. This year, natural gas reached \$1.48 per mcf, with oil trading at a healthy \$81 per barrel. Although a barrel of oil contains six times as much energy as an mcf of natural gas, WTI traded for an incredible fifty-two times Henry Hub natural gas – a nearly 90% discount on an energy-equivalent basis. Relative to oil, gas has only ever been cheaper once before, following the equally mild 2011-2012 winter.

FIGURE 1 Oil-Gas Ratio & Henry Hub Discount to Energy Equivalent

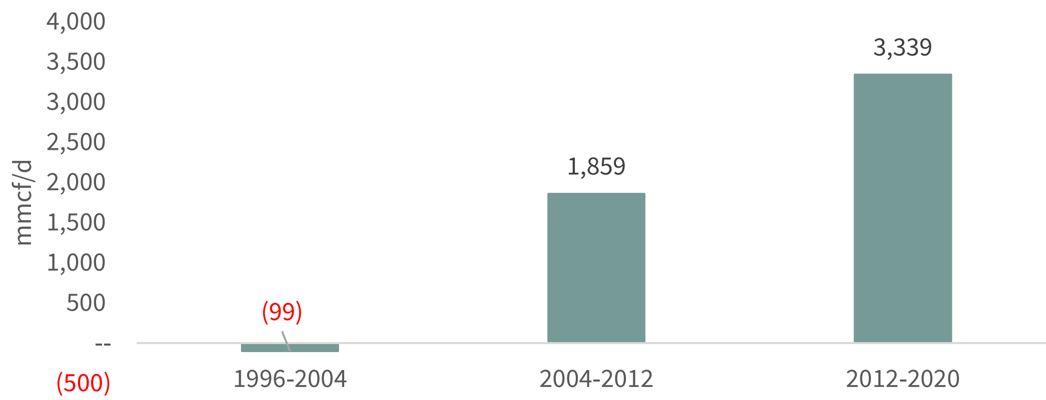


Source: Bloomberg.

Although the level of investor pessimism is comparable, today's North American natural gas market could not be more different than in 2012. Although the 2011-2012 winter was also 5% milder than average, North American gas inventories ended the 2012 heating season 900 bcf above average, compared with a surplus of 500 bcf today. In 2012, the shale boom was on the verge of ushering in an unparalleled surge in US gas production. The combination of horizontal drilling and hydrological fracture stimulation allowed independent exploration and production companies to produce gas from previously impermeable source rock.

After falling by 35% between 1970 and 2005, production first stabilized in the mid-2000s. In the eight years leading up to 2012, US dry gas supply grew by 14 bcf/d. Over the next eight years, it would increase by over 32 bcf/d, an incredible 50%. Throughout this period, production often grew by more than five bcf/d year-over-year. Several times, production growth exceeded 10 bcf/d in a single year. The incredible turnaround was entirely driven by the shales; conventional gas production continued to fall by 32% between 2012 and 2020. In total, shale production went from nothing more than a far-fetched dream to a 70 bcf/d behemoth by 2020. The gas shales produced more energy than Saudi Arabia's prolific oil fields on an energy-equivalent basis.

FIGURE 2 Average Annual Natural Gas Production Growth



Source: EIA.

The flood of shale gas overwhelmed the US market. Although utilities switched from coal to natural gas wherever possible, power generation could not absorb the excess. Crucially, the US could not export natural gas for most of this period; the first Lower-48 export terminals did not commence operations until 2017. With no outlet for the surplus production, North American natural gas prices decoupled from the rest of the world and they regularly began trading at a 40% to 60% discount on the world price.

TODAY, INSTEAD OF SITTING ON THE VERGE OF A MASSIVE PRODUCTION INCREASE, THE SHALE AGE APPEARS TO BE ENTERING THE EARLY STAGES OF DECLINE. PRODUCTION IS STILL GROWING YEAR-ON-YEAR, HOWEVER THE GROWTH HAS SLOWED FROM 10 BCF/D PER YEAR THROUGHOUT THE 2012 TO 2020 PERIOD TO A MERE 3.5 BCF/D . MOST IMPORTANT, ON A SEQUENTIAL BASIS, THE DRY GAS SUPPLY LIKELY PEAKED IN DECEMBER 2023.

t According to the latest data, February production remained nearly 1 bcf/d lower than December – the sharpest non-weather-related slowdown outside of COVID-19 since 2008. Instead of lacking LNG infrastructure, the US is now the world's largest gas exporter, with new terminal capacity set to surge over the next twelve months. More recently, analysts predict the promise of data center proliferation, driven by the rapid adoption of large language models, will usher in the most significant increase in domestic gas demand in US history.

The US is set to shift from a prolonged period of acute oversupply to a structural deficit of historic proportions. Although inventories remain high, our models predict they will draw to dangerous levels much sooner than anyone believes possible. Given this backdrop, it is unfathomable to us that US natural gas should trade at a record discount to its energy-equivalent price, even considering two consecutive mild winters. Investors should take note.

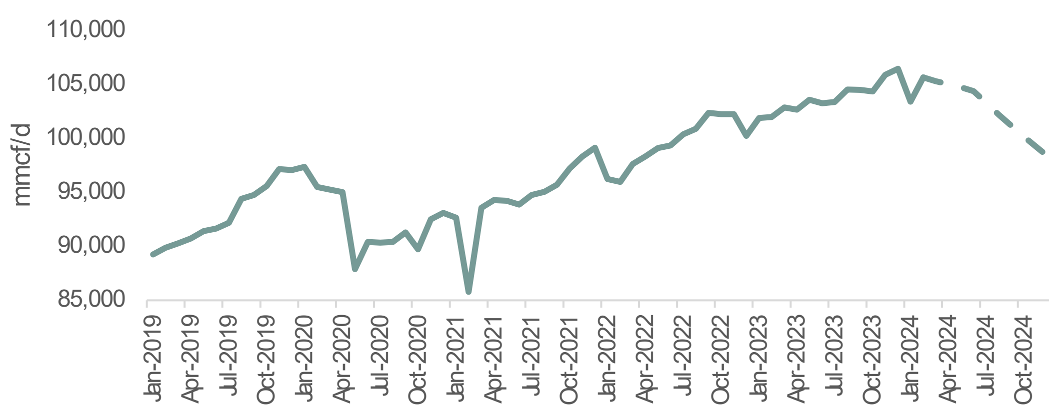
In many respects, the current natural gas market represents the perfect storm: dry gas production is faltering just as demand is set to surge. We have warned for several years that shale growth would slow. Our neural network models indicated that, although immense, the shale basins were not infinite. The Barnett and Fayetteville were the first two shale gas basins developed in the middle 2000s. Each field ramped up sharply before unexpectedly plateauing and declining by over 50%. We concluded that both fields peaked precisely once half their recoverable reserves had been produced, just as Hubbert's theories predicted. By applying these same principles to the Marcellus, Haynesville, and Permian (collectively 75% of total shale gas production) we warned growth would soon begin to slow before production rolled over entirely in 2025. It appears we were too conservative; US gas supply has likely peaked already.

As we mentioned, the US produced nearly 1 bcf/d less dry gas in February than the peak in December. Preliminary data suggests production declines will accelerate. The U.S. Energy Information Administration (EIA) expects June shale production to fall by another 2bcf/d compared with February. Our internal models confirm the persistent declines. If the expectations are accurate (and we believe they are), total US dry gas production likely will fall by over 2 bcf/d between December 2023 and June 2024 – the sharpest six-month decline outside of COVID-19 since our data began.

Although it garnered no attention, in the latest Short-Term Energy Outlook (STEO), the EIA predicted that full-year 2024 dry gas production would fall by 1% compared with 2023. For this to happen, production must drop by an incredible 7 bcf/d between February and December 2024, breaking below 100 bcf/d for the first time since June 2022.

The EIA expects US dry gas production to rebound sharply, making a new all-time high of 105 bcf/d in 2025, but we believe this prediction is too optimistic. The shales would have to arrest their declines and add nearly 1 bcf/d each month next year. The EIA expects Henry Hub gas will average $3.10 per mcf in 2025, too low to elicit the huge drilling rebound needed to bring about this change. Between June 2021 and January 2023, gas averaged $5.67 per mcf, never once dropping below $3.10 and yet production growth only averaged 380 mmcf/d per month. Production grew at less than half the rate implied in the EIA's 2025 projections despite a gas price that averaged 82% higher.

FIGURE 3 Historical and Projected US Natural Gas Production



Source: EIA and G&R Models.

THE ONLY TIME MONTHLY SHALE GROWTH EVER CONSISTENTLY APPROACHED 1 BCF/D WAS IN 2017-2019; HOWEVER, THE SHALES WERE FAR LESS DEVELOPED THAN TODAY. IN 2017, WE ESTIMATE THE MARCELLUS HAD ONLY PRODUCED 30% OF ITS TOTAL RECOVERABLE RESERVES, COMPARED WITH OVER 50% TODAY.

The only time monthly shale growth ever consistently approached 1 bcf/d was in 2017-2019; however, the shales were far less developed than today. In 2017, we estimate the Marcellus had only produced 30% of its total recoverable reserves, compared with over 50% today. Similarly, the Haynesville and Permian had made 25% and 30% of their recoverable reserves, respectively, compared with 50% today. Last decade, the Fayetteville and Barnett started their declines once half their reserves were produced. Our models suggest the same thing will happen with the Marcellus, Haynesville, and Permian. As a result, we believe the massive rebound the EIA expects next year will not be possible.

Making matters worse, the average well quality in the Marcellus, Haynesville, and Permian is steadily deteriorating, another indication of imminent field exhaustion. Cumulative six-month gas production per lateral foot in the Haynesville is 5% below the peak set in 1Q21. In the dry gas section of the Marcellus, productivity is 19% below the 4Q21 peak, while in the liquids-rich section of the play, productivity is 3% below the 2Q22 peak. In the Delaware side of the Permian, productivity peaked in 2019 and is currently 11% lower. In the Midland, productivity peaked in 2Q2020 and is currently 12% lower. Between 2017 and 2019, productivity steadily improved, providing a solid tailwind for monthly production growth. With productivity declining, we believe the same robust growth will be impossible.

Just as supply is set to falter, demand is expected to surge. The most critical driver is LNG terminal capacity. Over the next eighteen months, exports will increase by 4 bcf/d as three new domestic projects come online. Plaquemines is expected to commence commercial operations in the third quarter, ramping to 1.3 bcf/d. Corpus Christi will start next at 1.3 bcf/d, followed by Golden Pass in 2025 at 1.4 bcf/d. By mid-2027, an incremental 5 bcf/d of additional capacity is expected to come online, bringing total LNG exports to an incredible 20.4 bcf/d compared with less than 12 bcf/d today, the sharpest three-year growth in US history. Furthermore, both Canada and Mexico are sanctioning new LNG export capacity that could impact US supply. LNG Canada's $30 bn Kitimat project will start up later this year, reaching its 1 bcf/d Phase I capacity in 2025. Although this gas will be sourced from Western Canadian Sedimentary Basin fields, it can potentially impact the nearly 8 bcf/d currently imported via pipeline from Canada. New Fortress Energy is almost ready to commission its Mexican Altamira project, which will liquefy 1bcf/d of US gas imported via pipeline. Along with the US terminals, these two projects will further tighten the North American market.

In addition to export demand, domestic gas consumption for electricity is expected to rise materially in the coming years, driven by the proliferation of data centers and artificial intelligence. Over the past several months, we have read countless articles detailing the energy demand from generative AI, such as ChatGPT. Some of the best work comes from Rob West at Thunder Said Energy who quantified the potential impact. Although he is uncertain about some of his projections, demand will be material. Modern artificial intelligence consists of two distinct phases: training and inference. During the training phase, vast quantities of computing power optimize trillions of parameters (or neurons) across zettabytes of textual data. This process consumes an enormous amount of energy. It is estimated that training GPT-4 alone consumed 50 GWH of electricity, equivalent to the average annual consumption of 5,000 American households. Once a model has been trained, end users queried it, a process known as "inference." Although each inference requires only a fraction of the energy needed for training, a single model might be queried billions of times. West estimates a ChatGPT "inference" requires ten times as much energy as a Google search -- 3.6 Wh compared to 0.3 Wh. Generative AI's total energy consumption is a function of several related variables: the number of new models trained per year, the complexity of each model, the energy efficiency of new AI chipsets, and the total queries per trained model.

Although it is beyond the scope of this essay to dissect each assumption, a few key drivers are worth discussing. First, many analysts expect energy efficiency to improve, mitigating energy demand growth. Unfortunately, this violates Jevons Paradox – a concept discussed in our 3Q23 letter. Jevons observed in the seventeenth century that instead of lowering demand, improved steam-engine efficiency dramatically increased English coal consumption. Although steam engines were becoming far more efficient, lower operating costs increased their proliferation, offsetting any gains and increasing overall coal demand.

Jevons Paradox is even more pronounced with generative AI. Supercomputer energy efficiency is measured in giga-flops per watt. Despite having improved five times since 2018, the total energy required to train an AI model has increased by an incredible 5,000 times. Training GPT-4 required fifty times more energy than a 2022-vintage model. As chips become more energy efficient, model complexity grows exponentially, requiring more energy to train. Furthermore, the number of distinct models has also grown exponentially. A significant number of more complex models has dwarfed any improvement in chipset energy efficiency, a trend that we expect will continue.

Second, despite the rhetoric around "green" data centers, we expect generative AI electricity demand will fall primarily to natural gas for two reasons. First, West estimates that the cost of training an AI model is five times more sensitive to electricity utilization than to price. As a result, both wind's and solar's inherent intermittency preclude them from being viable sources of electricity to power AI data centers. Second, even when a PV solar or wind installation generates power, the "quality" of the electricity, measured by its harmonic distortion, is unsuitable for the sensitive hardware used to train and query AI models. As a result, we believe the widespread proliferation of AI must be met with either coal, natural gas, or nuclear-based power. It is unlikely that new coal-fired power will be sanctioned in the US and the lead time on new nuclear power plants is too long to meet demand over the next several years. Therefore, natural gas should be the primary beneficiary of the AI rollout through the decade's end.

A MODERN DATA CENTER IS EXPECTED TO NEED AS MUCH ENERGY AS EVERY DATA CENTER DOMINION HAS CONNECTED SINCE 2019. INTERESTINGLY, THE TWO MOST ADVANCED SMALL MODULAR REACTOR COMPANIES, TERRAPOWER AND OKLO, ARE BACKED BY BILL GATES AND SAM ALTMAN, RESPECTIVELY.

The impact of AI's relentless power demand is already being felt. In May 2024, Dominion announced that new data centers in Virginia, used to train and query AI models, require several gigawatts of power, equivalent to several large nuclear power plants. t However, we do not expect either of these technologies to be rolled out until at least the end of the decade. In the interim, we believe natural gas demand will surge.

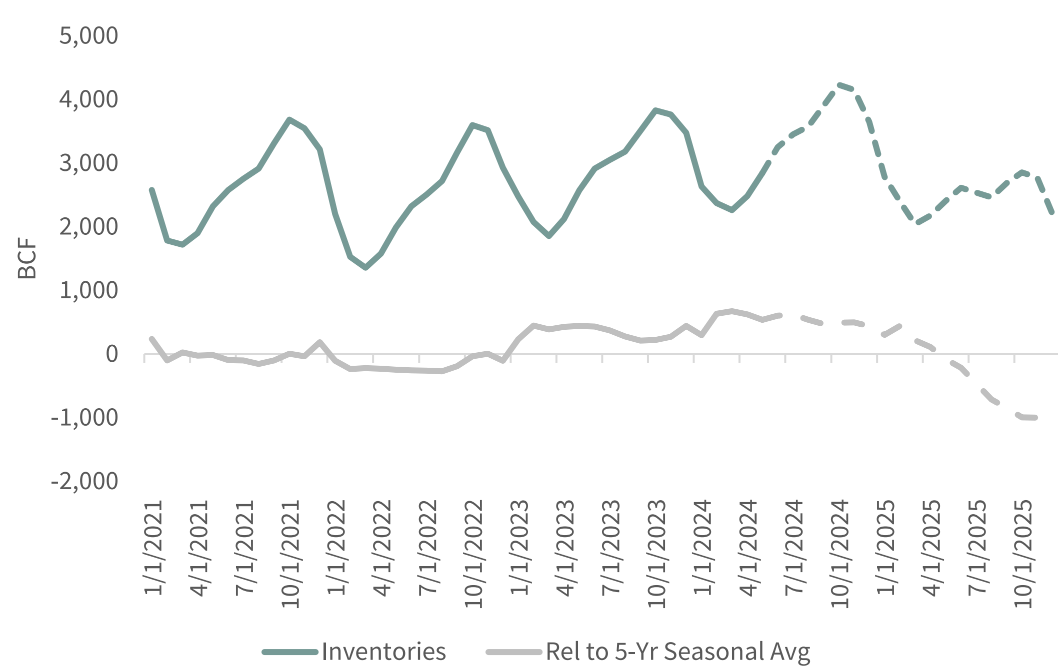
Although estimates vary, West believes 150 GW of AI data centers will be required by 2030, consuming 1000 TWH annually. Assuming 40% of global data center capacity is installed in the United States, AI data centers will consume 400 TWH of electricity, requiring 7 bcf/d of natural gas. Such a buildout would represent the largest increase in gas-fired power capacity in US history.

While West focuses on the energy needed to operate AI models, Mark Mills has tried to quantify the energy required to build the computer infrastructure. In his book, The Cloud Revolution, Mills outlines the massive energy needs of modern computing infrastructure. Although he notes that companies often do not fully disclose the energy needed to build modern data centers to power AI models, we have attempted to quantify the energy required to build out 150 GW of AI data center demand by 2030. Manufacturing high-performance semiconductors is energy-intensive. Although our numbers are preliminary, we believe manufacturing a modern data center consumes at least 8,500 MWh per MW of capacity. Reaching 150 GW of newly installed capacity by 2030 will consume an additional 2,500 TWH of electricity, or 430 TWH per year – nearly 50% as much energy as required to power the centers. Although most semiconductor fabs are located outside the United States, a strong push exists to relocate manufacturing domestically. Regardless of where the chip manufacturing is situated, it is clear that building out 150 GW of data centers will require a tremendous amount of energy, further tightening global energy markets.

In our view, US natural gas demand is set to grow at the fastest rate in history between now and 2030. At the same time, dry gas production appears to have peaked. While analysts are hopeful that a rebound is forthcoming, we are not as optimistic. The shale gas revolution resulted in a dramatic increase in supply, but as we have argued, immense is not the same as infinite. More than half of reserve estimates have now been produced in every major shale basin, an event that has corresponded historically with falling production. If our models are correct, and we believe they are, the most significant gas demand increase in history will occur just as production begins to falter.

US natural gas inventories are currently 2.7 tcf, nearly 600 bcf above seasonal averages. Although high by historical standards, our models suggest inventories will normalize as we progress through 2024 and into 2025. Assuming average weather, we expect inventories to work off all their surpluses early next year. By next fall, inventories could stand at record deficits. Although weather always remains a wild card in natural gas markets, new demand from LNG and AI combined with slowing shale production will likely overwhelm any period of mild weather.

FIGURE 4 US Natural Gas Inventories



Source: EIA and G&R Models.

Today's North American natural gas market bears no similarity to 2012. And yet, Henry Hub natural gas traded recently at a 75-90% discount to both the seaborne LNG and oil-equivalent price. Simply put, this is not sustainable. We believe natural gas-related equities represent exceptional value today. While gas stocks have dramatically outperformed the gas price since the start of 2023, their valuations remain incredibly depressed. For example, Range Resources today trades 30% below where it did in 2012 when natural gas prices were comparable. Over that period, proved reserves per share increased by 138%and the balance sheet improved. We calculate that the debt-adjusted SEC PV-10 per share increased nearly five- times since 2012. At current levels, we calculate Range Resources is pricing in a realized price of $2.62 per mcf, in line with the depressed spot price. If Henry Hub gas prices rebounded to only $4.00, Range's debt-adjusted SEC-PV10 value would exceed $80 per share compared with $36. At $8.00 gas, in line with world prices, Range would be worth over $200 per share.

Although we have been very early, we believe North American natural gas, with less liquefaction and transportation, will converge with the global price, currently $10 per mcf. Investors are extremely bearish after two back-to-back mild winters but are neglecting the bullish shifts in both supply and demand currently underway. This is the most asymmetric investment we can recall.

Remember 1970 and 2000

WTI Crude Oil

1/1/1970: $3.18

2/15/1981: $34.30

1/1/2000: $25.55

7/14/2008: $145.18

The theories of King Hubbert are about to become once again highly relevant. What follows is the first in a series of essays in which we will cover many of his most important views. Hubbert is best known for "peak oil," his framework for predicting when global oil production will peak, plateau, and roll over. We have written about peak oil in the past and will revisit it in an upcoming letter. For those interested in the interim, we recommend listening to our debate with Doomberg on Adam Taggart's podcast from January 25, 2024.

Today's essay focuses on how Hubbert's theories could have been used to predict the massive crude bull markets of the 1970s and 2000s. Using them as a guide, we will explain why we believe we are on the verge of a bull market of similar magnitude today.

In the 1970s, oil advanced ten-fold as the world experienced two distinct oil crises: the Arab embargo of 1973 and the Iranian revolution in 1979. In the 2000s, oil advanced thirteen-fold, stopped only by the onset of the global financial crisis in 2008, the most severe economic dislocation since the Great Depression.

During both periods, "Hubbert's Peak" captivated the investor zeitgeist and dominated discussions of why oil prices were so high. However, in retrospect, we know these fears about hitting "Hubbert's Peak" were wrong. Oil production grew sharply in the twenty years following the 1970s and the decade following 2008. Following each spike, oil entered long, grueling bear markets and Hubbert's theories became widely discredited and almost entirely forgotten.

Nevertheless, Hubbert's teaching provided lessons that predicted both bull markets. To reject his theories out of hand would be ignoring their essential principles. Armed with Hubbert's theories, an analyst in either 1970 or 2000 could have confidently predicted the huge bull markets that were to come. A similar situation is unfolding today.

BOTH BULL MARKETS WERE DRIVEN BY PREDICTABLE, ALBEIT UNDERAPPRECIATED, CHANGES IN NON-OPEC OIL SUPPLY. IN THE 1970S, THOSE CHANGES TOOK PLACE IN THE UNITED STATES. BY 1970, THE US WAS BY FAR THE WORLD'S LARGEST OIL PRODUCER. PRODUCTION PEAKED IN 1970 AT 11.3 MM B/D – SIGNIFICANTLY GREATER THAN THE COMBINED PRODUCTION OF SAUDI ARABIA AND RUSSIA, THE WORLD'S SECOND AND THIRD LARGEST OIL PRODUCERS.

Both bull markets were driven by predictable, albeit underappreciated, changes in non-OPEC oil supply. In the 1970s, those changes took place in the United States. By 1970, the US was by far the world's largest oil producer. Production peaked in 1970 at 11.3 mm b/d – significantly greater than the combined production of Saudi Arabia and Russia, the world's second and third largest oil producers. Between 1965 and 1970, US production growth represented 30% of total non-OPEC growth. Although US production had spent the preceding sixty years growing steadily, it was about to roll over and spend the next forty years declining. Hubbert predicted that peak fourteen years earlier in his dinner speech at the American Petroleum Institute in 1956. In that presentation, Hubbert presented two possible scenarios. In the second scenario, which he confirmed in 1962, he predicted US production would peak in 1970 at 10 mm b/d.

Production peaked in 1970 exactly as Hubbert predicted, and by 1976 production had already fallen 15% or by 1.6 mm b/d. Lost supply and surging demand meant the US's need for imported oil surged. Between 1970 and 1976, US net imports more than doubled, rising from 3.4 m b/d to nearly 8 m b/d by 1976. The dramatic increase in US net imports gave OPEC and Saudi Arabia a significant advantage in market share and pricing power. Between 1970 and 1974, OPEC went from representing 46% of global crude production to 52%. OPEC first leveraged its improved market share in 1973, when the Arab oil producers engineered a tripling of oil prices in only six months in retaliation against the United States' support of Israel in the Yom Kippur War. After the Iranian revolution in 1979, OPEC again exerted its influence, causing prices to double. Using its new price power related to market share gains, OPEC was able to produce a ten-fold increase in oil prices in ten short years and to change the geopolitical orientation of the world for years to come.

A similar situation developed in the 2000s. Throughout the late 1990s, Saudi Arabia and Venezuela (both OPEC member countries) waged a price war over disagreements around OPEC production quotas. Crude prices collapsed to $11 per barrel in the first quarter of 1999. Demand was then materially impacted following the September 11, 2001terrorist attacks, putting further downward price pressure on crude. At the same time, non-OPEC oil supply grew sharply in the early part of the 2000s. Russian production rebounded as companies, such as Yukos, began adopting modern Western drilling and oil service techniques. Surging non-OPEC supply and weak demand produced a universally bearish oil market psychology. Although it is hard to believe, most investors in the early 2000s failed to appreciate the coming surge in Chinese oil demand growth.

Despite the bearish outlook, forces were at work in non-OPEC supply that would significantly tighten the market and severely disrupt the bearish narrative, much like what happened back in the early 1970s. Investors and analysts willing to do the original research and apply various geological theories to the modeling of various hydrocarbon basins would recognize what these forces were and how they would impact non-OPEC supply.   In its February 9,, 2004 edition, Barron's published an interview with Leigh Goehring (then the Jennison Global Natural Resources Fund manager) titled "Pumped Up: A Natural Resource Maven Sees a Long-Term Bull Market for Oil."

In that article a crucial point was highlighted: "We are just beginning to see a noticeable slowdown in non-OPEC oil supply, which is bound to pass more power into the hands of the oil cartel. Energy is undergoing a massive underlying change, and people are not yet interested in accepting it. In 2004, the gap between perception and reality will close."

Over the previous two decades, the two most significant sources of non-OPEC supply growth were the North Sea and Mexico's Cantarell field. Both fields ramped up in the early 1980s and reached a combined 7 mm b/d by 2004, equivalent to 60% of all non-OPEC growth. By 2004, both fields were on the verge of a significant development that few analysts predicted: they were about to decline. By applying Hubbert's theories, we were one of the few investors who anticipated the slowdown, and we positioned ourselves accordingly.

DISAPPOINTING PRODUCTION IN BOTH FIELDS CAUGHT NEARLY EVERYONE BY SURPRISE. BASED ON THEIR FIRST PUBLISHED ESTIMATES FOR EACH PERIOD, THE INTERNATIONAL ENERGY AGENCY (IEA) PREDICTED THAT THE NON-OPEC OIL SUPPLY WOULD GROW BY 6.6 M B/D BETWEEN 2003 AND 2008. INSTEAD, OWING TO MASSIVE DISAPPOINTMENTS IN THE NORTH SEA AND MEXICO, NON-OPEC PRODUCTION ROSE BY A MERE 2.2 M B/D, 65% BELOW THEIR INITIAL EXPECTATIONS

Disappointing production in both fields caught nearly everyone by surprise. Based on their first published estimates for each period, the International Energy Agency (IEA) predicted that the non-OPEC oil supply would grow by 6.6 m b/d between 2003 and 2008. Instead, owing to massive disappointments in the North Sea and Mexico, non-OPEC production rose by a mere 2.2 m b/d, 65% below their initial expectations and far less than the 6 mm b/d demand growth over the same period. As a result, OPEC again gained market share and pricing power, forcing crude prices to rise by nearly 350%.

For those who studied Hubbert's teachings, disappointing supply in the decade of the 2000s was entirely predictable. Our research strongly suggests the oil market is again entering a period similar to 1971 and 2003.   For analysts and investors who understand and apply Hubbert's theories, the investment opportunities are significant.

Over the last thirteen years, the US has provided almost 90% of total non-OPEC supply growth, far more than the US in the period leading up to 1970 or the North Sea and Mexico in the period leading up to 2003. Similar to the US in 1970 and the North Sea and Mexico in 2003, our models suggest the US shale production is about to roll over.

Hubbert believed that production would decline once an oilfield had produced half its ultimate recoverable reserves. This underpinned his prediction that the US would peak in 1970. Similarly, we used our estimates of the North Sea and Cantarell reserves to predict they, too, would roll over in the early 2000s. Combining our proprietary shale neural network with Hubbert's teachings, we believe the shales have produced over half their recoverable reserves. If our modelling is correct, production disappointments in the shales are rapidly approaching.

Except for King Hubbert in the 1970s and Colin Cambell and Jean Laherrère in the 2000s, no one predicted that the US, North Sea, or Cantarell would roll over. Few analysts today believe the US shales will roll over, but with the help of Hubbert's theories and our models, we do.

Shale growth has been slowing for several years. The slowdown in non-OPEC supply has already impacted oil markets. The US has been forced to orchestrate a 320 mm barrel release of strategic petroleum reserves and OPEC is flexing its regained market share and pricing power. On April 3, OPEC renewed its production cuts, even though many agencies, including the IEA, anticipate crude deficits later this year.

Crude markets are at an inflection point similar to 1970 and 2003, yet investors remain more complacent than ever. In the early 1970s, the energy weighting in the S&P 500 bottomed at 15% before reaching an all-time high of 35% in 1981. In 1999, energy's share of the S&P 500 bottomed at 6% before reaching a high of 15% in 2008. As we write, with crude at $78 per barrel – nearly seven times higher than in 1999 – the energy weighting of the S&P 500 cannot break 4%. Investors are convinced energy stocks remain "uninvestable."

FIGURE 5 Energy Weighting in S&P500

Source: Bloomberg & CRSP Data via French Data Library.

That Took Awhile - Somebody Finally Recognizes the Dangers of the IEA

The following is an excerpt from an open letter written by John Barrasso, M.D., Ranking Member of the US Senate Committee on Energy and Natural Resources, and Cathy McMorris Rodgers, Chair of the US House Committee on Energy and Commerce, to Dr. Fatih Birol, Executive Director of the International Energy Agency dated March 20th, 2024:

Dear Dr. Birol:

We are writing to you because we are concerned that the International Energy Agency (IEA) has strayed from its core mission—promoting energy security.

Indeed, we would argue that the IEA has been undermining energy security in recent years by discouraging sufficient investment in energy supplies—specifically, oil, natural gas, and coal. Moreover, its energy modeling no longer provides policymakers with balanced assessments of energy and climate proposals. Instead, it has become an "energy transition" cheerleader.

[…]

The IEA also provides global energy forecasts as part of its mission. As you have noted, IEA forecasts tremendously influence how the world sees future energy trends. Consequently, the IEA must conduct its energy security mission objectively. We believe the IEA is failing to fulfill these responsibilities.

Although it took quite some time, people finally realized how misguided the International Energy Agency has become and the potential danger embedded in its bias. In our 2Q22 introductory essay, "The IEA Ushers In the Coming Oil Crisis," we detailed many of the same concerns Senator Barrasso and Congresswoman McMorris shared.

ALTHOUGH IT TOOK QUITE SOME TIME, PEOPLE FINALLY REALIZED HOW MISGUIDED THE INTERNATIONAL ENERGY AGENCY HAS BECOME AND THE POTENTIAL DANGER EMBEDDED IN ITS BIAS. IN OUR 2Q22 INTRODUCTORY ESSAY, "THE IEA USHERS IN THE COMING OIL CRISIS," WE DETAILED MANY OF THE SAME CONCERNS SENATOR BARRASSO AND CONGRESSWOMAN MCMORRIS SHARED.

The IEA was established by the Organization for Economic Co-operation and Development (OECD) to monitor oil supplies following the 1973 oil crisis. Its central mission was to prevent shocks caused by unanticipated severe oil supply disruptions, by thoroughly researching and reporting on global energy markets. In an ironic twist, on May 18th 2021, the EIA released a white paper entitled "Net Zero by 2050." In the report, the IEA insists that the global energy industry significantly curtail upstream investments and redirect capital into renewable energy. The irony of the widely cited report is apparent: were the industry to follow its advice, the IEA would usher in the supply shock it was created to prevent. Verging on the absurd, Dr. Birol even included the IEA's mission statement in the report: "Since the IEA's founding in 1974, one of its core missions has been to promote secure and affordable energy supply to foster economic growth."

Earlier in this letter, we analyzed two periods when oil prices rose more than ten-fold. In each case, non-OPEC supply growth slowed, ceding market share and pricing power to the OPEC bloc. If energy companies heed the IEA's advice, OPEC will gain market share again and prices will likely rise. This reality was not lost on the IEA: "The contraction of oil and gas production will have far-reaching implications for all the countries and companies that produce these fuels. [...] Supplies will become increasingly concentrated in a small number of low-cost producers. OPEC's share of the much reduced global oil supply will grow from around 37% in recent years to 52% in 2050 -- a level higher than at any point in the history of oil markets."

It is naïve for the IEA to think OPEC will not exercise pricing power given its rapidly rising market share. In the 1970s, the OPEC market grew by six percentage points, and prices surged ten-fold. In the 2000s, it grew by three percentage points and prices rose thirteen-fold. By the IEA's own admission, its proposed policies will see OPEC's market share grow by fifteen percentage points. What impact will these policies have on price?

We invite you to read the Senator and Congresswoman's full letter here.

The choice between energy security and climate change is a false one. There are solutions that address both concerns, such as natural gas and nuclear power. Unfortunately, the IEA seems uninterested in seriously addressing the issues. Instead, they remain aggressive advocates of energy policies designed to usher in the next energy crisis. At least others are taking notice.

What Can GAAP Accounting Teach Us About the Energy Transition?

In the wake of the 1929 stock market crash and the Great Depression, the Securities and Exchange Commission (SEC) embarked on an ambitious journey to formalize accounting rules and practices for publicly listed companies. This decades-long endeavor culminated in establishing Generally Accepted Accounting Practices (GAAP) in 1970—a robust framework that standardized financial calculations and reporting, thus bringing clarity and order to the corporate financial landscape.

Yet, no such standardization exists in the domain of the energy transition. The trillions of dollars we believe have been squandered on wind, solar, and electric vehicles highlight the critical need for a standardized framework. Such a framework is not merely desirable but essential for avoiding malinvestment on a grand scale.

In earlier essays, we delved into the concept of Energy Return on Investment (EROI), a principle advanced by Professor Charles Hall in the 1970s. EROI gained prominence in the early 2000s amid the specter of peak oil, serving as a tool to measure the energy intensity of oil production, particularly from the Canadian oil sands. Analysts fretted that the increasing energy consumption required to extract oil from these sands would diminish EROI, thus stymying economic growth.

The shale revolution in the United States momentarily dispelled these fears and EROI studies receded into the background. However, in 2016, we reignited the debate, applying Hall's framework to the emergent wind, solar, and electric vehicle industries. Professor Vaclav Smil, in his critically acclaimed 2017 book Energy and Civilization: A History, chronicles humanity's relentless pursuit of greater energy efficiency. Historically, every new energy technology adopted has surpassed its predecessor in efficiency. We used the EROI framework to test whether wind and solar could outperform crude oil and natural gas. If they did, these renewables would inevitably displace hydrocarbons, prompting a shift in our investment strategy. If not, the transition away from hydrocarbons would stand as one of history's greatest misallocations of capital, rendering traditional energy stocks extraordinarily undervalued.

Our analysis revealed that wind and solar energy offer an EROI markedly inferior to traditional hydrocarbons. Similarly, the total energy required to power an electric vehicle using renewable sources for a distance of 100 miles significantly exceeds that of an internal combustion engine. Our previous letters detail these findings.

At first, our views were outliers. However, the mounting challenges energy transition companies face have sparked renewed interest in our conclusions. In our exploration of "The Norwegian Illusion," (4Q2023 G&R Commentary) we recently debunked many claims championed by the renewable power and EV industries.

While our arguments have primarily been well-received, some questions linger about the precise calculation of energy efficiency and EROI. The variability in data and conclusions among analysts necessitate clarification and reconciliation of misconceptions.

The crux of the ambiguity lies in the calculation of EROI itself, hindered by a lack of standardization. The "energetic boundary" problem encompasses two key issues: where to stop tallying energy inputs, analogous to Scope 1, 2, and 3 emissions in carbon accounting. For instance, in a wind project, one must account for the energy required to mine iron ore, smelt steel, and construct turbines. But should we include diesel for transporting the workforce or energy in their food and housing? Establishing a consistent boundary is vital, as undercounting total energy requirements is expected. Yet, the substantial energy required in upstream and manufacturing processes means minor boundary errors are usually immaterial.

A more significant issue is categorizing energy requirements. Here, GAAP can be instructive. EROI is typically the ratio of usable energy output to energy input. Consistently distinguishing operating energy costs from capital energy costs, just like what is done in financial accounting, is essential for calculating consistent and comparable EROI figures.

Consider a hypothetical financial investment: a manager commits $100 million to build a factory producing 100,000 widgets annually for twenty years. The widgets sell for $800 each, with direct operating costs of $700, generating $80 million in annual revenue and $10 million in profits. With an initial $100 million capital expenditure, the factory yields a 10% return on investment, doubling the company's initial outlay over twenty years—a sound investment.

However, if viewed as "money in" versus "money out," an analyst might mistakenly conclude the facility barely covers its costs. Total revenue generated over twenty years is $1.6 bn compared with $100 mm to build the facility and $1.4 bn to produce the individual widgets. Such faulty reasoning would suggest $100 mm of profit ("money out") and $1.5 bn of cost ("month in"). Dividing the two would yield a twenty-year total return of only 6%, or 0.33% per annum. GAAP principles clarify that the former analysis is correct; the latter is flawed. Properly distinguishing operating cost from capital cost correctly predicts the company ends with twice the cash after the facility's useful life.

UNFORTUNATELY, NO COMPARABLE FRAMEWORK EXISTS FOR STUDYING ENERGY SYSTEMS. THIS LACK OF STANDARDS LEADS TO ILL-INFORMED DECISIONS AND INCONSISTENT CALCULATIONS ACROSS DIFFERENT TECHNOLOGIES, HINDERING LIKE-FOR-LIKE COMPARISONS.

Unfortunately, no comparable framework exists for studying energy systems. This lack of standards leads to ill-informed decisions and inconsistent calculations across different technologies, hindering like-for-like comparisons.

For example, calculating oil's EROI begins with the energy for exploration, drilling, and well completion. The wellhead EROI might be 60x, meaning 6,000 units of energy produced from 100 units invested. However, oil must be transported and refined, consuming 15% of its energy content – or 900 units. This reduces the net EROI to 50x. If, instead, we misclassified the 900 units used to refine crude into gasoline as simply "energy out," we might erroneously conclude the oil well delivered 6,000 units of energy against costs of 1,000 units (100 units at the wellhead and 900 units downstream), suggesting an incorrect EROI of 6x, a nearly 90% drop for the very same system.

Energy analysts inconsistently apply these principles to renewables. For instance, a wind turbine might generate twelve times the energy needed to build it, resulting in a gross EROI of 12x. If the turbine required 100 units of energy, it would produce 1,200 units over its life. With 15% power loss to grid interconnections, the net available energy would be 1,020 units. Analysts often subtract line losses from the generated renewable power, concluding an EROI of 10x, inconsistent with how they treat oil wells. We have seen many studies that suggest gasoline has a societal EROI of 6x compared with wind power of 10x, suggesting wind is the better choice. A consistent methodology instead confirms gasoline's EROI as 50x compared to wind's 10x – suggesting gasoline is far preferred.

GAAP offers guidance on whether a cost should be expensed or capitalized. Costs for acquiring, upgrading, or extending a long-lived asset's duration should be capitalized. Average operating costs incurred in the same period as the output should be expensed. Direct operating costs, attributable to production units, are always expenses, never capital charges. Using this framework, energy used for crude transportation and refining and line loss from wind turbines are all clearly operating charges and should be treated as such.

Correctly calculating returns is crucial for assessing future surplus. Just as a manager can predict cash surplus from a widget factory, we must determine future energy surplus from investments. Misguided methodologies have contributed to today's energy crisis.

Professor Hall, a pioneer in EROI studies, is now working to standardize these issues.

Adhering to GAAP-like principles for energy calculations can help us better navigate the energy transition and ensure that investments yield sustainable, long-term returns.

2024 Q1 Natural Resources Market Commentary

While oil and gold were strong during the first quarter, most other commodities were flat to down. Investors remain uninterested in natural resources. They are concerned about several factors, including the threat of global economic softening, a collapse in the Chinese property sector, and the risk the Fed might delay future rate cuts. Technology stocks boomed, driven by the AI craze, pulling investor capital away from other sectors, such as resources. The Goldman Sachs Commodity Index returned 10.3% during the quarter, driven by oil's strong performance. The Rogers International Commodity Index, with less energy and more mining exposure, returned less than half the GSCI, advancing by 5.4%. Natural resource equities moved higher during the quarter. The S&P North American Natural Resource Stock Index, with its large energy weighting, returned 11.2%, while the S&P Global Natural Resource Stock Index, with more weighting to mining and agricultural-related stocks, returned only 2.3%. The S&P 500, driven by the "magnificent seven," rose 10.1%, while the MSCI All-Country World Index advanced 7.8%.

Oil

Driven by strong demand, oil rebounded 16%, making it the best-performing commodity during the first quarter. The IEA again raised its global demand estimates in its Oil Market Report, albeit convolutedly. After actual demand came in higher than expected in the first quarter, the IEA revised the first and second quarters up by 600,000 and 200,000 b/d, respectively. However, in a move repeated many times over the past fifteen years, they simultaneously revised the second half of 2024 demand lower, keeping their full-year 2024 estimate unchanged at 103.2 mm b/d. Many analysts reported that the IEA revised oil demand lower for the rest of the year, which, although technically correct, neglects the significant upward revisions in the first half. We believe that similar to past years, the IEA will eventually be forced to revise its second half and, by extension, the entire year of 2024 and the figures. Although the consensus believes oil demand is weak, our models suggest it remains strong. India has joined China in its "S-Curve" sweet spot, where energy demand in general and oil demand in particular grows faster than GDP, and just like China since 2003, we believe the IEA's models are not adequately capturing this bullish shift. Oil production, particularly in the US shales, has been disappointing, just as our models predicted. We believe the second half will be extremely tight and oil prices will increase sharply.

Natural Gas

Natural gas was one of the worst-performing commodities in North America and internationally, driven by a milder-than-normal end to winter in the US and Europe.

Henry Hub gas fell by 30% in the US, while prices fell by 14% and 17% in Europe and Asia, respectively. Extreme investor pessimism has gripped the gas markets. Earlier in April, oil approached $90 per barrel while gas traded for $1.70 per mcf, taking the oil-gas ratio to a record 52 times compared with an energy equivalency of six times. At those prices, natural gas energy content traded at a 90% discount to its crude oil equivalent. The only other time in history the oil-gas ratio has been this large (and gas has been this cheap) was following the mild 2011-2012 winter. However, as we discussed in our introductory essay, today's gas market bears no similarity with 2012. The US could not export LNG twelve years ago and shale production was set to surge. Today, the US is the world's largest gas exporter, with a record amount of additional capacity set to come on stream in the coming months. Shale production, meanwhile, peaked in December 2023 and has since declined by 2 bcf/d. The near-term outlook is for further production declines, a shift that few investors imagined a few months ago but that our models correctly predicted.

Although the weather has been kind to natural gas bears, we believe things may soon change. Several high-profile weather forecasting firms have warned of near-record hurricane activity this season. The likelihood of solid storms remains high as warmer-than-normal Atlantic waters combine with a change from El Niño to La Niña conditions. Despite media reports of extreme weather, relatively few hurricanes have hit the Gulf of Mexico over the past several years, putting little pressure on offshore production, which still represents 5% of total US production even after the shale revolution. Any weather-related disruptions could seriously impact gas balances throughout the summer.

Finally, data center proliferation could lead to the largest increase in US gas-fired electricity generation in history. Be sure to read the introduction of this letter, where we discuss all these bullish drivers in detail.

Uranium

Uranium surged in the first quarter in response to Kazatomprom's surprise January 12th announcement that its 2024 production goals would not be met. After starting the year at $91 per pound, spot prices rallied to $106 following the announcement. Surging prices coaxed out what little remains of secondary supply, causing prices to pull back to $83 by mid-March before ending the quarter at $88 per pound.

In recent years, Kazatomprom has stated that it will materially increase production in 2024 and 2025, responding to stronger-than-expected utility demand. We were always skeptical that the company could meet their guidance, and their January 2024 announcement confirmed our suspicions. We traveled to Almaty, Kazakhstan to meet with the company in March and were more convinced than ever that production would continue to disappoint.

We believe the uranium bull market is underway. Although we remain bullish, the sector is no longer as obscure or unloved as when we initially invested in 2018, with spot prices below $20 per pound. With every investment theme, we construct a road map that helps us determine if we are progressing down the right path. Our road maps were accurate with uranium. We must now ask ourselves when we expect this bull market to end. Unlike many commodities, uranium suffers little in the way of demand destruction. Unlike natural gas or coal-fired electricity, nuclear fuel is a small portion of a utility's total costs. Instead, supply security is paramount. Therefore, the uranium bull market will ultimately be undone once the new mine supply ramps up. Thus far, we are going in the opposite direction, with Kazatomprom and Cameco announcing disappointments. As a result, we believe that, for the time being, the bull market will continue. Some of our uranium holdings have reached their price targets and we have used the strength to trim certain positions. However, uranium remains a core position, and we are comfortable with our current holdings. Please read the Uranium section later in this letter. We will go into greater detail on all of the supply and demand developments in this dynamic sector.

Base Metals: A Mixed Quarter

The performance of base metals during the quarter was mixed. Nickel increased by 1%, aluminum dropped by 2%, and zinc fell by more than 8%. Copper stood out as the strongest performer, advancing nearly 3%.

As tracked by the S&P Global Base Metals Index, base metals equities trended higher during the quarter, advancing by 8%. Copper stocks were solid, with the COPX ETF rallying 13%. Copper remains our preferred base metal for the next several years. However, we want to highlight the potential impact of new technologies that could increase supply by the decade's end – something that as of yet is not impacting our bullishness short term.

We now have the full-year 2023 copper supply and demand figures which are increasingly bullish. According to data from the World Bureau of Metal Statistics (WMBS), global copper demand in 2023 rose by a robust 7.5%. While copper demand in the OECD world fell by 2.7%, demand in the non-OECD world, which now accounts for nearly 75% of global copper demand, surged by a robust 11.7%. China's demand increased by 12%, but notable growth in other large non-OECD economies also caught our attention.

Demand in non-OECD countries outside China now makes up 15% of global demand, underscoring its rising significance. Among these countries, India stands out as the most critical to watch. Indian copper consumption rose by almost 22% in 2023. Between 2005 and 2020, Indian copper consumption fluctuated between 400,000 and 500,000 tonnes per year. However, in the last two years, consumption has nearly doubled, and we believe it will double again in the coming years, mirroring China's copper consumption boom between 1999 and 2010 which rose six-fold.

Indonesia is another non-OECD country worth monitoring. From 2010 to 2020, Indonesia's copper consumption averaged around 200,000 tonnes per year, with total installed copper in the economy at only 35 pounds per capita -- too low given its $5,000 per capita GDP. With Indonesia's aggressive economic growth goals and efforts to escape the middle-income trap, 2023 saw a 30% surge in copper consumption compared to 2022.

Our demand models indicate growth will continue surprising to the upside as we progress through this decade, even before considering the need for renewable energy investments. However, supply-side issues persist. The resolution of the Cobre Panama crisis remains unclear, leaving 330,000 tonnes of copper mine supply, approximately 1.7% of global production, offline. Issues with Chilean supply abound. In 2023, global mine supply increased by about 3%, or approximately 500,000 tonnes, significantly below demand growth.

Future supply growth will primarily come from two countries: the Democratic Republic of

Congo (DRC) and Mongolia. In 2023, the DRC increased production by 360,000 tonnes, with over 50% coming from the stage two expansion of Ivanhoe's massive Kamoa-Kakula mine. Another 200,000 tonnes are expected with the Stage 3 expansion, set to be completed by the end of 2024. Rio Tinto's Oyu Tolgoi underground mine, which has been delayed for a long time, is ramping up and should add approximately 400,000 tonnes of new production between now and 2027. However, this new supply will barely offset underlying depletion.

We have often predicted that a structural deficit would soon emerge in the global copper markets due to strong demand and disappointing mine supply. Investors ignored the bullish developments last year owing to concerns over China's property sector and fears of a global recession. In hindsight, 2023 was likely the year copper slipped into deficit.

In 2022, refined copper demand was 25.8 million tonnes, mine supply was 21.6 million tonnes, and scrap copper totaled 4.9 million tonnes. Taken together, the market was in surplus by 700,000 tonnes in 2022. In contrast, by 2023, demand reached 27.7 tonnes, mine supply totaled 22.3 mm tonnes, and scrap fell to 4.8 mm tonnes. The 700,000-tonne surplus in 2022 shifted to a 600,000-tonne deficit by 2023.

Copper's recent breakout to $5.00 per pound, combined with plunging treatment and refining charges for concentrates (TC/RC), confirms the copper market is now structurally tight. The first leg of the bull market began in 1Q16 when prices bottomed at $1.95 per pound. Prices peaked at nearly $5 per pound in 1Q22 following Russia's invasion of Ukraine. However, recessionary fears drove prices 35% lower from their 2022 peaks. Copper's two-year correction is finally over as the market is finally coming to terms with underlying physical tightness.

Coal: An Opportunity in the Shadows

The global coal market was notably subdued in the first quarter, with coal prices retreating. U.S. Powder River Basin coal prices declined by 2.5%, Central Appalachian prices dropped by 4%, and Illinois Basin coal prices fell by 3%. International thermal coal prices followed suit, with Newcastle thermal coal plunging almost 18% and South African thermal coal, loaded at Richards Bay, decreasing by 3%. Even metallurgical coal prices, as measured by high-quality Australian met coal, dipped by 1%.

After leading the market for the past three years, the few remaining publicly traded coal companies have pulled back significantly, mirroring the softness in coal prices. Despite the pressures from environmental, social, and governance (ESG) that make coal investments problematic for most, a new buying opportunity may be at hand for those able to navigate these challenges. Edward Chancellor, the esteemed investor and market historian, advocates for investing in industries where stocks are cheap and capital has been scarce for years. Coal fits this description perfectly. No sector has been more deprived of capital over the past decade than coal.

Most private equity firms, banks, and investment firms have been barred from investing in the coal industry, leaving coal stocks at rock-bottom valuation levels. The three coal stocks we hold trade at an average trailing price-to-earnings ratio of just seven, compared to 25x for the S&P 500. Historically, in the three major commodity bull markets of the past 120 years, coal equities have been the leaders, and a similar pattern seems to be emerging as this commodity bull market begins.

Since the onset of the current commodity bull market in the summer of 2020, the three coal equities mentioned have appreciated on average by 4,200%, vastly outstripping the 300% return of the S&P North American Natural Resource stock index over the same period. For investors who can withstand the ESG pressures, the recent pullback in coal equities presents another compelling investment opportunity.

In conclusion, while global coal prices have retreated and public sentiment remains subdued, the fundamentals suggest a contrarian opportunity. The sector is starved for capital, and valuations are historically low. Coal equities could offer significant upside potential for those willing to take the risk as the commodity bull market progresses.

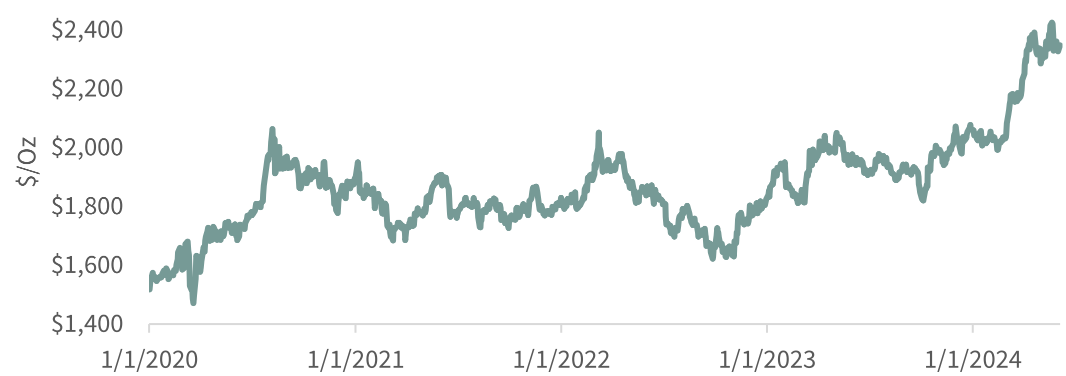
Precious Metals: A Glimmer of Strength Amidst Market Turbulence

Gold and silver stood out in the first quarter, showing notable strength. Gold advanced by 11%, while silver rose by 3%. However, this strength did not extend to platinum group metals: platinum and palladium fell by 8%. Gold and silver equities were mixed: the GDX gold equity ETF rose by 2%, whereas the SIL silver equity ETF fell by 4%. The most significant news in the gold market during the quarter was the substantial breakout in mid-February.

After trading sideways for four years, gold prices broke through the resistance level at $2,050 and surged to $2,400 by mid-April. As we have observed in previous quarters, two significant trends dominate gold markets: central banks are aggressively buying aggressively, while western investors are aggressively selling.

Longtime readers will know our stance: a monumental monetary regime change is on the horizon. The exact nature of this change remains uncertain, but we firmly believe it will be extraordinarily positive for gold. Historical parallels can be drawn from the monetary shifts of 1930, 1968-1971, and 1997-1999, each heralding significant bullish gold phases. We have consistently advised our readers to maintain substantial exposure to gold, silver, and related

FIGURE 6 Gold Price



Source: Bloomberg.

equities, especially given their current undervaluation.

In this letter's Precious Metals section, we delve deeper into the dynamics of central bank purchases, western investor sell-offs, and a significant shift in gold investment behavior among retail investors in China and India. We believe a new and substantial bull market in gold and silver has commenced, with precious metals prices poised for significant upward movement.

With central banks continuing to buy and western investors retreating, the stage is set for the gold rally to continue. Also, as we stand on the brink of what we believe to be a substantial monetary shift, making the case for precious metals even more compelling. We urge our readers to heed this moment and position themselves accordingly in the gold and silver markets.

Agriculture: The Gathering Gloom Over Grain Markets

The first quarter of 2024 saw grain prices continue their downward slide. Apart from a few exceptions like cocoa, which has benefited from El Niño-related weather disruptions, a pervasive gloom has settled over global agricultural markets. Corn slipped by 6% in major grain markets, soybeans fell by 8%, and wheat dropped by over 10%. Since their peaks in the first half of 2022, following Russia's invasion of Ukraine, corn, soybeans, and wheat have pulled back by 50%, 40%, and 60%, respectively.

As the Northern Hemisphere planting season kicks off, the USDA, through its World Agricultural Supply and Demand Estimates (WASDE), has published its first projections for the 2024-2025 growing season. The report casts a slightly bearish shadow over the market. The USDA projects a 5% reduction in planted and harvested acreage for U.S. corn. Based on a regular growing season and weather-adjusted trends, they forecast a record yield of 181 bushels per acre, up 2% from last year's 177.3 bushels per acre. Despite the projected 3% decrease in the corn crop size, stable demand, and last year's large ending-stock carryover led the USDA to project a slight increase in 2025 ending stocks, now expected to reach 2.1 billion bushels. This level has not been seen since the 2019-2020 growing season, when corn prices averaged $3.75 per bushel, compared to today's price of $4.60.

The USDA forecasts a nearly 4% increase in planted and harvested acreage for soybeans. They project a record yield of 52 bushels per acre, assuming average weather and planting conditions. The total harvest is estimated to grow by 7%, while usage is expected to increase by 6%. Ending stocks for the 2024-2025 season are estimated to grow to 445 million bushels, approximately 50% higher than the 30-year average. The last time soybean ending stocks exceeded these levels was between 2017 and 2019, when prices averaged around $10 per bushel, compared to today's $12.

While the WASDE report leans slightly bearish, much will depend on the weather as the 2024-2025 growing season unfolds. Speculators in global grain markets continue to grow bearish and the risk of significant weather disruption, particularly in the U.S. Midwest, is increasing. Russia's invasion of Ukraine triggered the first agricultural crisis of this decade and we believe conditions are now ripe for a second crisis. Grain and fertilizer prices have declined for the past two years, investor sentiment is at a nadir, and valuations are incredibly cheap.

In the Agricultural section of the letter, we delve into intriguing data points that have emerged in global agricultural markets. The market's pervasive bearishness and heightened weather risks set the stage for potential turmoil. As we stand on the cusp of another growing season, the agricultural sector is primed for dramatic shifts. Investors who recognize the cyclical nature of these markets and the critical role of weather patterns may find compelling opportunities amid the current gloom.

Gold's Pitched Battle

The gold market remains locked in a pitched battle. Western investors continue to sell their gold while central banks and Chinese and Indian retail investors continue to buy aggressively. With gold making record highs, it is clear who is winning.

Western speculators liquidated 108 tonnes during the first quarter, based on the eighteen physical ETFs we monitor. This trend has accelerated in the second quarter, with the same ETFs liquidating 50 tonnes in the six weeks since April 1st.

Stubbornly high inflation, combined with hawkish rhetoric from the Federal Reserve, has confounded many investors. At the start of the year, many anticipated five or six rate cuts in 2024. Many Fed watchers have given up on any rate cuts for the remainder of the year, while some are now anticipating further hikes.

Rising real rates always lead western investors to liquidate gold; this cycle has been no exception. However, instead of falling, gold is making new highs. From late 2011 to 2015, US real rates surged by 3.5%, as the Fed Funds Rate remained at ten bps while inflation decreased from 3.5% to zero. The increase in real rates led western speculators to liquidate 1,150 tonnes of gold, pushing the price down by a massive 45%.

Since the summer of 2020, US real rates have increased by 2%. Like in 2011, western speculators have aggressively liquidated gold, shedding 950 tonnes from the ETFs. However, instead of falling by 45%, gold advanced by 20%, making new all-time highs.

Although gold's rise has surprised many investors, we have discussed its drivers for the last eighteen months. Our 1Q23 letter concluded, "Central banks are the key to understanding the difference between the 1970s and today." central banks became massive gold buyers, more than offsetting the western speculator liquidation. Since 2021, central banks, led by China, started accumulating vast amounts of gold. In 2021, the central banks purchased 425 tonnes. In 2022, they accelerated their purchases to 1,136 tonnes – the most in over seventy years. Central banks continued buying in 2023, accumulating 1,037 tonnes, according to the World Gold Council (WGC).

SUBSTANTIAL ACCUMULATION CONTINUED INTO THE FIRST QUARTER OF 2024, WITH CENTRAL BANKS PURCHASING 290 TONNES – AN ALL-TIME FIRST-QUARTER RECORD ACCORDING TO THE WGC. CHINA REMAINS THE LARGEST BUYER, HAVING PURCHASED 27 TONNES IN THE FIRST QUARTER AND EXTENDING THEIR BUYING STREAK TO SEVENTEEN CONSECUTIVE MONTHS.

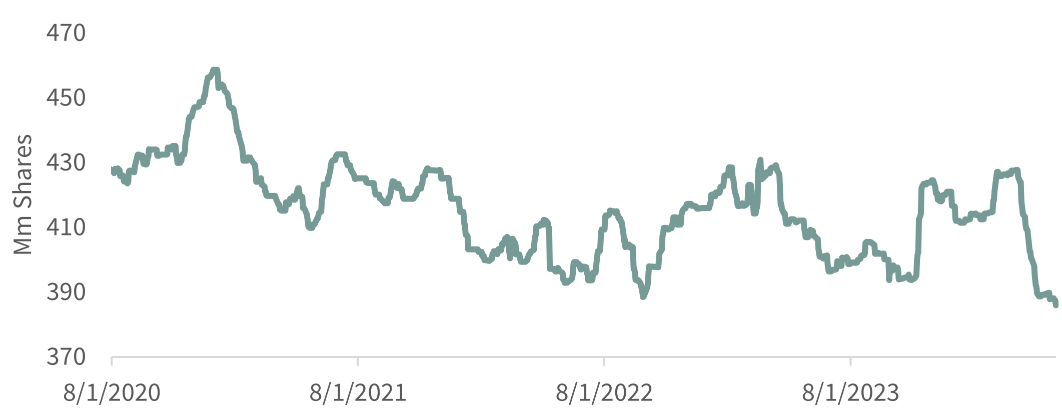
Substantial accumulation continued into the first quarter of 2024, with central banks purchasing 290 tonnes – an all-time first-quarter record according to the WGC. China remains the largest buyer, having purchased 27 tonnes in the first quarter and extending their buying streak to seventeen consecutive months. Since October 2022, when China started buying gold, they have increased their holdings by 16% to 2,262 tonnes. India purchased 17 tonnes during the first quarter – as much as all last year combined. The Singaporean central bank purchased gold in the first quarter as well. Singapore did not buy gold in the fifty-two years between 1968 and 2020. They re-entered the gold market in 2021 and have been accumulating consistently. In 2021, they purchased 26 tonnes, followed by 77 tonnes in 2023, increasing their total holdings by nearly 50% from 154 to 230 tonnes.

Why are central banks purchasing so much gold? We expect a change in the monetary regime to take place sometime soon. In previous letters, we have explained how such changes have always followed periods where commodity prices were radically undervalued relative to financial assets. Prior periods of radical commodity undervaluation occurred in 1929/30, 1968/71, and 1997/99. Today's commodities are more radically undervalued than at any time in the last 140 years. Just like in the past, we believe a monetary regime change is forthcoming and that the central bank's massive gold accumulation signals that the change might occur much sooner than anyone thinks possible. Each of the previous three monetary regime shifts was highly bullish for gold. Please read the 1Q23 essay "The US Reserve Currency & Commodities," in which we carefully analyze each of the three periods.

Western investors have been equally bearish on gold-related equities despite gold making new all-time highs. Shortly after gold peaked at $2,050 per ounce in August 2020, the shares outstanding of the GDX gold miners ETF peaked at 460 mm shares. Gold trades nearly 20% higher than the 2020 peak, yet shares outstanding in the GDX have fallen by 15% or 60 mm. Western speculators have recently continued liquidating gold mining equities despite the rally. Although gold has advanced by 12% since the first week in March, speculators have liquidated 10% of their holdings in the GDX ETF.

The last gold bull market lasted from the middle of 1999 until August 2011. Over that period, gold advanced from $253 to $1,900 per ounce. Western participants, led by European central banks, were net gold sellers throughout the bull market. While some western speculative interest developed following the 2008 global financial crisis, it was short-lived. After a massive decade-long bull market, total gold holdings by western gold investors (including

FIGURE 7 GDX Shares Outstanding



Source: Bloomberg.

the central banks) had decreased. The entire five-fold increase in the gold price occurred despite the West's continued liquidation. How could gold rally sharply with no western participation? Chinese and Indian retail investors turned into massive gold buyers, carefully accumulating every ounce—and then some--sold by the West.

When eastern buying drives a precious metal rally, it tends to advance in an orderly manner, with few gaps higher. The eastern buyer, for whom gold is a fundamental part of the cultural identity, prefers to buy during periods of weakness and sell during periods of strength, providing ballast and stability to the market. Western investors tend to do the opposite: increase their interest as prices rally and dump metal when they sell off.

Over the past five years, high prices have largely discouraged Chinese and Indian retail buying. However, in their 1Q24 Gold Demand Trends report, the WGC highlighted how both Chinese and Indian retail demand has surged. Given gold's recent strength, eastern retail demand is unusual. Chinese retail purchases totaled 110 tonnes in the first quarter,70% higher than in 2023, despite gold having rallied by 10%. Indian retail investment demand rose to 41 tonnes – 20% higher than one year ago.

The World Gold Council summarized this anomaly:

"Western and eastern markets tend to see contrasting trends in gold investment….Typically, investors in eastern markets are more responsive to price and will tend to react to a sharp rise by sitting on the sidelines (waiting for a pause or corrective pullback in the price as an opportunity to buy) and/or by taking profit and cashing in on their gold investments. Western investors have historically been attracted to a rising price and tend to buy into the rally. The most recent quarter has seen those roles reversed."

Western investors will likely become aggressive gold buyers once real rates fall, driven by either a Fed rate cut or rising inflation. If this were to happen, western buying would compete with central bank purchases. If eastern buyers are no longer as price sensitive as in the past, then all three groups could simultaneously bid for gold, putting extreme upward pressure on price. Since 1999, gold rallies have been extremely orderly, thanks to offsetting behavior from eastern and western investors, with central banks primarily relegated to the sidelines. Are we entering a period of extreme gold volatility, last seen during the 1970s?

Unless they are careful, western investors risk missing most of the move. In the 1999-2011 rally, western investors only purchased gold at the very end, once the bull market was mostly over, and immediately ahead of a significant pullback.

Gold can rally with little western participation-it certainly did in the 2000's, and the gold bull market currently unfolding seems to be following a similar pattern.

IN OUR PRIOR LETTERS, WE ANTICIPATED THAT THE ALL-TIME MONTHLY PRODUCTION RECORD WOULD LIKELY BE SET IN 2024. LOOKING BACK, IT SEEMS WE UNDERESTIMATED THE SITUATION. AFTER A VIGOROUS DECEMBER, US PRODUCTION BEGAN TO RECEDE, DROPPING BY 135,000 B/D BY MARCH.

Oil Shales Have Peaked

The primary source of non-OPEC oil supply growth has finally crested. As 2023 began, the United States produced an additional 1.1 million b/d year-on-year. Yet by the time November rolled around, this torrent had diminished by 75%, slowing to a mere 275,000 b/d compared with the previous November. In our prior letters, we anticipated that the all-time monthly production record would likely be set in 2024. Looking back, it seems we underestimated the situation. After a vigorous December, US production began to recede, dropping by 135,000 b/d by March.

Shale propelled the unexpected boom in US oil production over the last decade. Our neural network models began sounding the alarm in 2019, indicating that further growth in shale would be challenging as producers fully developed the prime areas of the Eagle Ford, Bakken, and Permian basins. At that time, we projected that the Eagle Ford and Bakken were nearing their peaks, with the Permian likely to peak in 2025. True to form, the Eagle Ford has peaked and has since declined by 36%. The Bakken peaked in late 2019 and has since fallen by 15%.

The Permian, the largest and youngest of the shale plays, now appears to have also peaked. According to the EIA, the Permian reached its zenith in December 2023 at 6.2 million b/d, only to fall by 60,000 b/d over the next four months. Total shale production peaked in December, dropping by 155,000 b/d by March. Preliminary estimates for June hint at a modest recovery, but production is still expected to remain 127,000 b/d below December's record, marking the worst six-month period in shale history outside of the COVID-19-related downturn and the 2016 Saudi-led price collapse.

As previously discussed, the oil market must now contend with losing its most significant source of non-OPEC production growth. Since 2010, the US has accounted for 87% of total non-OPEC production growth. Since 2019, non-OPEC production outside the US has been in decline. Historical precedents from 1970 and 2003, when the largest sources of non-OPEC supply growth (the US and North Sea/Mexico, respectively) slowed, demonstrate how this shift ceded market share and pricing power to the OPEC bloc, causing crude prices to surge nearly ten-fold in both instances.

Complicating matters further, demand remains robust. From its initial estimates for 2024, first released last summer, the IEA has revised demand higher by 100,000 b/d. However, this figure doesn't tell the whole story. As data arrived, the IEA revised the first-half 2024 demand by 300,000 b/d while simultaneously lowering the second-half 2024 demand by 200,000 b/d. Based on our research and experience with the IEA, we believe these downward revisions were made to avoid significantly increasing full-year 2024 demand projections. Our data suggests that global demand remains strong, and we believe the IEA's projections will ultimately need to be revised upward as the year progresses. We expect 2024 demand to average 103.5 million b/d, a 1.4 million b/d increase compared with 2023. For next year, the IEA anticipates demand will grow by 1.1 million b/d from its 2023 projections, reaching 104.3 million b/d, but we believe this estimate is likely too conservative.

Long-time readers will recall our discussions of "missing barrels." In its Oil Market Report (OMR), the IEA lists supply, demand, and changes in inventory, which, in theory, should balance. In practice, they rarely do. Instead, the IEA introduces a line item called "Miscellaneous to Balance," which we call the "missing barrels," oil that has been produced but neither consumed nor stored. "Missing barrels" are often revised away when the IEA adjusts demand higher or supply lower. In the first quarter, the IEA reported a negative "missing barrel" figure, suggesting either demand was lower or supply was higher than reported. We will monitor this closely, but we are not concerned for now. Shipping challenges in the Red Sea distorted oil markets during the first quarter.

Consequently, the IEA reported that oil in transit surged by 1 million b/d, comparable to the 800,000 b/d of "found oil." We believe the IEA likely overstated the oil in transit figure and, by extension, the anomalous "found oil" line item. We should know more as second-quarter data becomes available.

Global crude oil markets have been largely balanced over the past two years. Since March 2022, commercial inventories have increased by 140 million barrels, while government inventories have drawn by 228 million barrels, leaving total inventories 87 million barrels lower. Adjusted for seasonal averages, inventories have drawn by 47 million barrels or a modest 100,000 b/d. We believe this is about to accelerate dramatically.

The IEA expects the second half of 2024 demand to average 104 million b/d, while they expect supply to reach only 103.45 million b/d, indicating a deficit of 550,000 b/d. Under these assumptions, inventories will draw by 100 million barrels, ending the year at a record 472 million barrels below long-term seasonal averages.

Our models suggest inventories could draw down even more. First, as discussed, the IEA recently increased first-half 2024 observed demand while simultaneously lowering second-half estimates, leaving the full year unchanged. If robust first-half demand persists, the IEA could underestimate demand by 300,000 b/d. Second, the IEA expects US production to grow from 19.5 million b/d in the first quarter to 20.6 million b/d by the fourth quarter, even though production declined between December and March, with only slight increases expected through June. If US production remains flat for the rest of the year, global oil production might fall short by as much as 400,000 b/d. Instead of a 550,000 b/d deficit, oil markets could face a more than 1.2 million b/d shortfall, leaving inventories more than 550 million barrels below seasonal averages.

Demand and US production will be critical drivers in the second half. So far, both seem to be trending in a very bullish direction.

OIL MARKETS ARE NOW IN A SITUATION REMINISCENT OF 1970 AND 2003. IN ALL THREE INSTANCES, THE PRIMARY SOURCE OF NON-OPEC PRODUCTION GROWTH SLOWED DRAMATICALLY, SURPRISING MOST ENERGY ANALYSTS. INVESTORS REMAIN AMBIVALENT ABOUT ENERGY, BUT WE BELIEVE THIS IS ABOUT TO CHANGE. FLOWS IN THE PRIMARY ENERGY EQUITY ETFS REMAIN SHARPLY NEGATIVE AS INVESTORS CONTINUE TO REDEEM THEIR HOLDINGS. WE BELIEVE THIS IS A MISTAKE AND THAT THE MARKETS WILL TIGHTEN CONSIDERABLY AS THE YEAR PROGRESSES.

Oil markets are now in a situation reminiscent of 1970 and 2003. In all three instances, the primary source of non-OPEC production growth slowed dramatically, surprising most energy analysts. Investors remain ambivalent about energy, but we believe this is about to change. Flows in the primary energy equity ETFs remain sharply negative as investors continue to redeem their holdings. We believe this is a mistake and that the markets will tighten considerably as the year progresses.

The Uranium Roadmap: Expect More Upside to Come

The uranium bull market is in full swing. Our initial investments in this cycle date back to 2018, when uranium was priced below $20 per pound and Cameco's shares were trading at 75% of book value, around $10 each. As of the end of the first quarter, spot uranium stood at $89 per pound, contract uranium at $77.50 per pound, and Cameco's share price surpassed $50. Uranium, once considered an obscure and declining commodity, emerged as one of the hottest investment themes in 2023, with investor sentiment hitting bullish levels unseen in fifteen years.

We thrive in investing in severely out-of-favor industries, typically constrained by capital. Given the recent rally, many ask if we remain bullish on uranium. As this essay will elaborate, our short answer is yes; we believe prices will continue to rise significantly.

When entering a new investment, we develop a "road map" outlining how we expect the bull market to progress. In 2018, we concluded uranium prices were unsustainably low. If our models were correct, we anticipated companies would have to shut down primary operations. When Cameco closed McArthur River and Kazatomprom announced widespread production cuts in 2018, our confidence in our models grew.

Our road maps always include an expected exit point. We typically assess what long-term price would attract sufficient investment in new supply to offset depletion and meet projected demand growth. We also consider whether demand destruction or new supply will ultimately end the bull run. For uranium, we believe a long-term price of $125 per pound would, with adequate capital and lead time, bring on enough new mine supplies to meet reactor demand. Unlike other commodities, such as crude oil, demand destruction is less of a concern in the nuclear power sector. Uranium fuel costs are a minor fraction of a nuclear power plant's total costs, with capital costs being much more significant. Therefore, a nuclear plant's profitability is less sensitive to rising fuel costs than a coal-fired plant.

As a result, we focus more on supply changes than demand when deciding when to exit our uranium investments. The uranium industry has faced constant supply disappointments, suggesting this bull market has much further to run. Last fall, Cameco reported challenges in restarting Cigar Lake, its second-largest mine, which was also placed on care and maintenance along with McArthur River in 2018. Consequently, Cameco lowered its 2023 production guidance by 8% last September, sparking a sharp rally in uranium prices and equities.

Kazatomprom announced it would miss its 2024 production guidance by 9 million pounds in January and February due to sulfuric acid shortages and operational delays. While we had concerns about Kazatomprom's capacity, the announcement shocked the broader market. In August 2022, Kazatomprom responded to strong demand by planning to increase production to 55-56 million pounds by 2024, an 11 million pound increase compared to 2023. In September 2023, the company aimed to boost 2025 production to 68 million pounds, a 12 million pound increase over expected 2024 output.

On January 12th, Kazatomprom surprised the market by lowering its 2024 production guidance to 46-50 million pounds, a 7-10 million pound reduction from original projections. This announcement raised two crucial questions: how much of the 7-10 million pound increase was firmly committed in their forward sales book and will 2024 production issues spill over into 2025?

In April, we visited Kazatomprom in Almaty. They were noncommittal about how much of the initially projected 55-56 million pounds had been sold forward and how much uranium they might need to buy in secondary markets to cover contracted sales. The company mentioned excess inventory on its balance sheet and mid-year 2024 numbers will reveal more when investors reconcile inventory footnotes in their six-month financial reports.

GIVEN THE STRUCTURAL DEFICIT IN TODAY'S URANIUM MARKET AND NEARLY NON-EXISTENT INVENTORIES, THE WORLD NEEDS KAZATOMPROM'S 68 MILLION POUNDS OF 2025 PRODUCTION. ANY REDUCTION COULD CAUSE ANOTHER SIGNIFICANT SPIKE IN URANIUM PRICES. WE PLAN TO REVISIT KAZAKHSTAN IN THE FALL TO INSPECT THEIR FIELD OPERATIONS.

The more pressing issue is the potential significant shortfall in 2025 production. In January, Kazatomprom stated: "Should the Company not succeed in catching up with the construction works schedule at the newly developed deposits in 2024...a successful return to 100% of the Subsoil Use Agreements (67-69 million pounds of production) can be viewed as a risk." Even under perfect conditions, increasing production by 13 million pounds in 2025 versus 2024 seems challenging.

Given the structural deficit in today's uranium market and nearly non-existent inventories, the world needs Kazatomprom's 68 million pounds of 2025 production. Any reduction could cause another significant spike in uranium prices. We plan to revisit Kazakhstan in the fall to inspect their field operations.

Further complicating uranium mine production, Niger experienced a coup in 2023. Orano suspended production at its 5.2 million pounds per annum Somair facility, and Global Atomic's Dasa greenfield mine faced delays. Canadian greenfield projects, like Nexgen's

Arrow and Denison's Wheeler River mines, are progressing but unlikely to provide substantial new supply until the decade's end. Arrow, in particular, may face delays due to its aggressive construction timeline.

In the interim, new supply will come from restarts of old projects and some brownfield expansions, which will fall short of meeting current and future reactor demand. Consequently, we believe the deficit will worsen, pushing prices far above our theoretical long-term equilibrium of $125 per pound.

Reactor demand is growing sharply, driven by new reactor startups, life extensions at existing plants, restarts of curtailed facilities, and the promise of small modular reactors by the decade's end. Analysts now expect total reactor demand to grow by nearly 40% by 2030, compared with our previous estimate of 24%. Higher-than-expected demand adds 23 million pounds of uranium demand over our initial projections. New reactors are being commissioned in China, India, and Korea. China began constructing two new reactors in the first quarter alone and started fuel loading at its 1 GWe Fangchenggang Unit 4 reactor. India plans to triple nuclear power generation by 2030, adding 15 GWe of new reactor demand. Korea commissioned a new 1.4 GWe reactor in April and extended the operational life of three other facilities. Belgium announced life extensions at two facilities, while the Czech Republic and Egypt announced new projects. At COP28 last November, 20 countries pledged to triple installed nuclear power capacity by 2050.

According to our models, nuclear reactor demand will outpace mine supply by 170 million pounds between now and 2027. While reprocessing, underfeeding, and tail enrichment might provide 70 million pounds, the market is clearly in a structural deficit for the first time. Between 1980 and 2003, government stockpiles bridged the gap between reactor demand and mine supply. From 2003, down-blended Russian weapons material slowed, pushing the market into deficit, and prices surged ten-fold. Following the Japanese earthquake and tsunami on March 11, 2011, nearly 30% of the world's nuclear reactors shut down, creating a surplus. Since 2018, reactor demand has again exceeded mine supply, but extensive commercial inventories accumulated during the 2011-2018 period filled the gap. Now, we believe these inventories are depleted. Thus, the market must use price to coax out any remaining secondary supply to meet a primary deficit of 20 million pounds. We believe this deficit will worsen over the next few years, causing prices to surge.

Complicating matters, the US advanced a Russian fuel ban. It passed last fall and is expected to be ratified soon. The ban would sanction Russian uranium imports. While it's believed the sanctions will redirect Russian uranium to China and possibly India, they would likely increase Western uranium prices and tighten the uranium fuel chain.

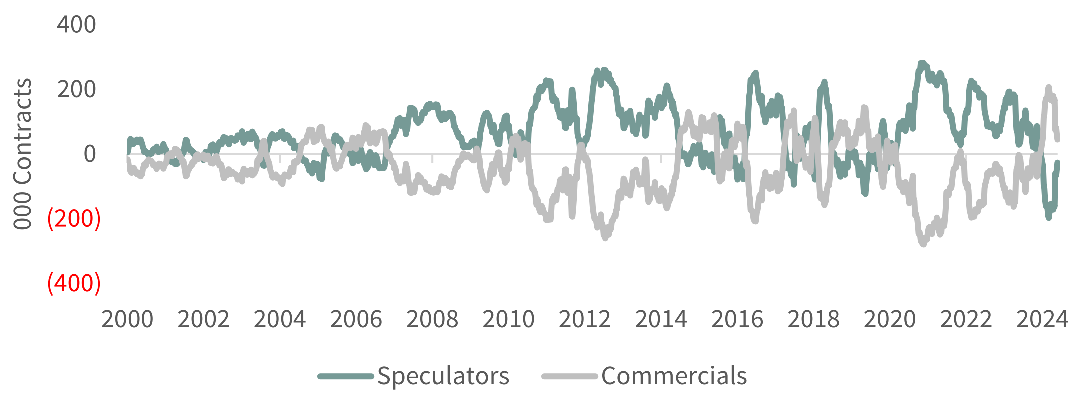
Uranium is no longer an unloved sector. However, based on our road map, we believe the rally will continue for several years. We are focused on new mine supply and today, the risk remains that supply surprises to the downside. Thus, we maintain our exposure to uranium-related equities, believing they will advance sharply over the coming years. Some investments have reached their long-term price targets based on our view of the sustainable equilibrium price. We've used recent strength to trim certain positions but maintain our core allocation. The uranium bull market is now in the early middle innings, to use a baseball analogy. While stocks are no longer as undervalued as when we initially invested, we believe they will continue to perform strongly.

Agriculture's Risk Looks to be to the Upside

Grain prices fell relentlessly as speculator bearishness reached extreme levels. This was particularly evident in the CBOE corn and soybean futures, which set new records of speculative short interest last quarter. These futures, being key indicators of market sentiment, reflect the growing bearishness among speculators. It's interesting that, as speculators became more and more bearish, commercial insiders became more and more bullish, indicating a potential divergence in market expectations.

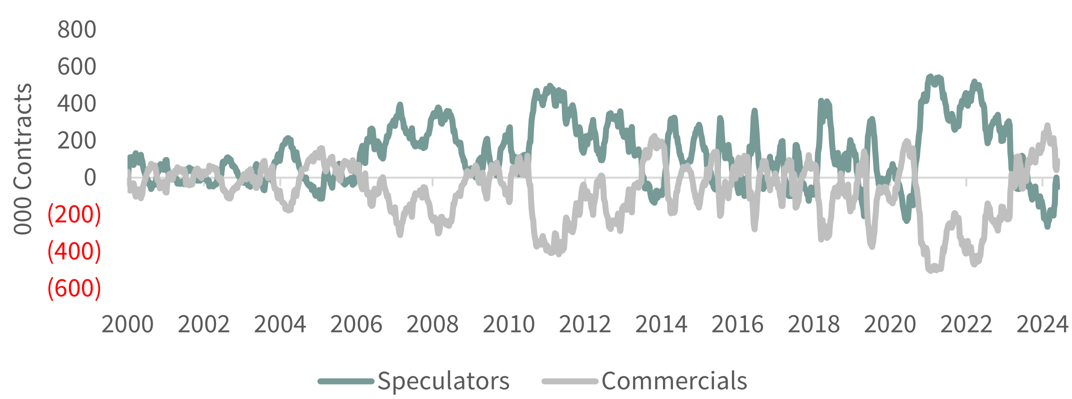
A paradox has unfolded in global grain markets. Prevailing belief is that climate change has led to more erratic, disruptive, and volatile weather patterns. Yet, the consensus among agricultural investors has never been more bearish. If changing climate is indeed causing more volatile weather, one would expect grain market volatility to dampen the enthusiasm for speculators to establish short positions. However, the more turbulent the weather, the

FIGURE 8a Soy CFTC Net Positioning



Source: Bloomberg.

FIGURE 8b Corn CFTC Net Positioning



Source: Bloomberg.

more bearish the speculative positioning, despite the heightened risk of crop failure.

Recently, Brazil has been grappling with severe weather conditions. Southern Brazil, a crucial soybean region, is reeling under widespread flooding. Northern Brazil, a key corn region, is battling scorching temperatures and persistent drought. Wheat crops across the Northern Hemisphere are also under threat. Russia is experiencing both drought and abnormally cold conditions, while Western Europe is dealing with excessive rainfall. In the United States, the winter wheat crop was adversely affected by poor growing conditions. Analysts now anticipate global wheat stockpiles to dwindle to levels not witnessed in a decade.

As our long-time readers know, sunspot activity is currently in a prolonged period of reduced activity. Historically, these periods have been associated with volatile weather and poor global growing conditions. Although the press has talked endlessly about the threat of climate change to food production, thus far, farmers have mostly been unaffected. For example, while large swaths of the US corn belt have experienced prolonged periods of extremely dry conditions, rains have always materialized in time to avert a large negative impact to crop yields. Nevertheless, subsoil ((the layer of soil below the topsoil) moisture and a critical factor for plant growth and resilience) remains extremely low. On a recent call with a substantial Iowa corn farmer, he confirmed that he has never seen such dry subsoil in his 30-year career.

Last fall, Brazil's northern soybean region suffered from record heat and extreme drought throughout most of the growing season. However, the rains arrived in time to save the crop. Although the USDA reduced Brazil's 2023/2024 soybean harvest projections by 5%, rain came to avert a much more significant potential impact.

In both instances, bearish grain traders "lucked out." However, weather volatility—mostly related to low sunspot activity—will eventually catch up with global grain markets. The implications could prove catastrophic.

Global growing conditions have been so favorable over the past thirty years that few people remember the devastating impacts of severe weather volatility. The 1930s serve as a stark reminder. The Dust Bowl was infamous for its lack of rain and record-breaking heat. In many cases, the high temperatures set ninety years ago still stand today. Based upon decreased sunspot activity, the probability of another Dust Bowl is much higher than anyone believes possible. This historical context should provide a deeper understanding of the potential impact of weather volatility on the agricultural market.

In our 1Q23 letter, we discussed the Gleissberg Cycle, a term referring to a long-term solar cycle associated with periods of extreme weather volatility. This cycle, driven by the regular reversal of the sun's magnetic fields every eleven years, occurs once every eight sunspot cycles, or approximately eighty-eight years. The last peak in the cycle occurred in the 1930s, concurrent with the Dust Bowl. Although modern instrumentation did not exist at the prior peak, tree ring studies suggest a period of extreme drought in the US Midwest in the 1840s. If the Gleissberg Cycle repeats itself every eighty-eight years, the next peak could occur at any moment. Investors, remain unprepared.

While the media portrays extreme weather volatility, recent conditions have been incredibly favorable compared to what happened in past Gleissberg Cycle peaks, notably the 1930s. The chart below is reprinted from the Hackett Agricultural Report. Over the past eleven years, Des Moines only experienced six days with temperatures over 100 degrees, compared with eleven days in 1930 alone. In 1933, it experienced eight 100-degree days. In

1934 and 1936, Des Moines registered an incredible thirty-one and thirty days above 100 degrees, respectively. Des Moines recorded eighty days above 100 degrees throughout the 1930s compared with only six days over the past eleven years.

Although we cannot be sure the Gleissberg Cycle will repeat, we believe it is imprudent for speculators to remain so wildly bearish. While weather can be notoriously difficult to predict, our analysis suggests an elevated risk of disruptive weather in the next few years. The agricultural bear market has persisted for two years. Low prices have largely mitigated further investment risks, and we believe the potential upside could be massive.