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Is This the Beginning of the End for Cheap Shale Gas?

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Inside…

Key Points:

- U.S. natural gas futures prices have fallen sharply since the start of the year, with 2023 setting up to be one of the most bearish years in recent history. However, longer term, the stage is set for tighter balances, rising prices and increased volatility.
- More exports, less opportunities for fuel-switching and supply bottlenecks could all contribute to rising energy bills.
- What's more, phasing out and possibly underfunding transition assets too early may result in greater price swings, raising security and affordability concerns.
- To buffer against rising prices, wholesale consumers should reconsider financial hedging but also incorporate adequate physical supply contracts to reinforce deliverability and reliability – in other words, an old school approach to a new set of problems.

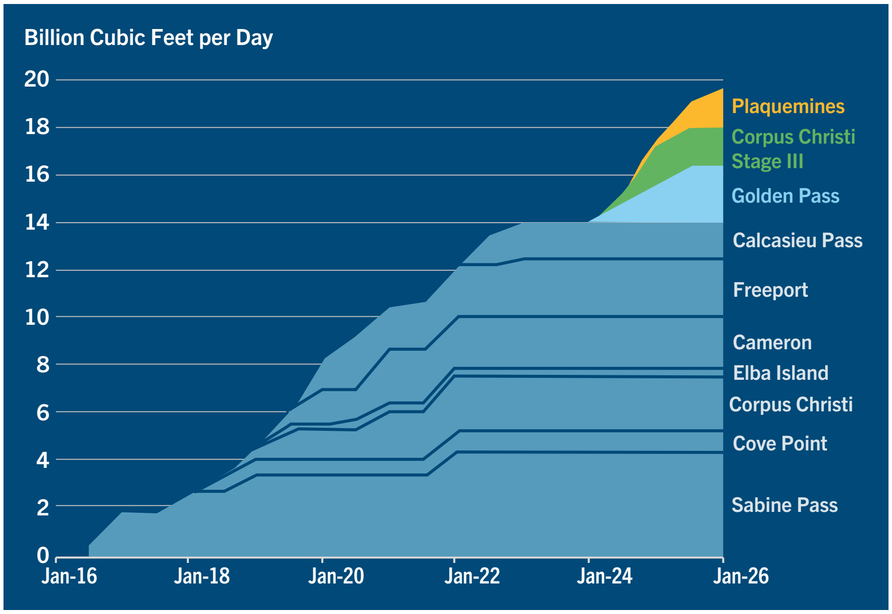
The Risk of Mismatching Energy Supply and Demand

Commodity traders often say that the cure for high prices is high prices. In other words, during periods of supply shortages or tight balances, sellers will increase their supply and buyers will cut back or adopt substitutes. However, the history of global energy is replete with examples of government policies influencing or interfering with market corrections. No other industry in the world is more heavily regulated than the energy industry, and by extension, none more prone to market distortion.

We live in an era of new governmental policies that are re-shaping global energy balances to an unprecedented degree. Short-term reform through subsidies, albeit humanitarian, have significantly distorted resource allocation over the past year.[1] These new energy policies pale in comparison to the clean energy spending that will come over a longer time horizon from the Inflation Reduction Act and the European Climate Law, bringing about an even greater reallocation of global energy resources. Energy transitions can be volatile and at times disjointed events; the lack of appropriate investment signals can create the risk of mismatch between energy supply and demand.[2]

EXHIBIT 1: U.S. Liquefied Natural Gas Export Projects

Existing and Under Construction (2016-2025)



Source: U.S. Energy Information Administration, Liquefaction Capacity File, Sept. 6, 2022

For U.S. domestic wholesale consumers, these tectonic global policy shifts add a new layer of complexity and cost to the energy transition underway. Indeed, the scramble to fund clean technology will likely come at the expense of limiting fossil fuel investment, possibly raising both costs for consumers.

In this comment, we will focus on the price implications of this shift for natural gas and discuss why the domestic market will be increasingly exposed to international market forces at a time when the traditional buffers have weakened. In our opinion, last year was an important turning point for natural gas globalization with greater agility now required from wholesale consumers to manage through periods of fuel scarcity.

U.S. LNG Exports Introduce Greater Resource Competition

Over the past century, the U.S. has operated as a natural gas island with domestic supply roughly sufficient to meet the nation's requirements and international trade mostly taking the form of cross-border pipeline balancing with Canada and Mexico. From a pricing perspective, domestic consumers – home or commercial building owners, chemical manufacturers and power plants, etc. – benefitted from their close proximity to world-class recoverable natural gas reserves, experiencing only brief periods of sustained high prices. However, this 'islanding' effect began to change with the outsized growth of U.S. production in 2006, with the expanded application of fracking and horizonal drilling technologies in shale formations. This rapid shale production boom led to the subsequent commissioning of large liquefied natural gas (LNG) export facilities on the Gulf of Mexico a decade later to absorb the excess.

Now, the domestic market looks vastly different than it did before the shale boom. The country produces almost double the amount of natural gas it did in 2006 and total exports now account for one-fifth of that production. In the next five years, upwards of 90% of gas demand growth could come from LNG exports, with perhaps as much as one-third of U.S. production possibly reserved for international trade.

Last year, when Russia cut off natural gas to most of Europe, it created a supply vacuum that enabled U.S. LNG terminals to form the market equivalent of a land bridge to Europe, laying the groundwork for greater resource competition for domestic consumers.[3] Indeed, Russia's invasion of Ukraine prompted a scramble by global gas buyers to shore up new LNG volumes by committing to new long-term contracts, thus paving the way for the next big construction cycle this decade. While the U.S. can already boast more LNG export capacity than any other producing nation, the country's liquefied natural gas shipping armada is about to get bigger, potentially doubling in size *(Exhibit 1).*[4]

This LNG growth will convert a mostly captive market to one that is at least partially exposed to world prices. As Mark Finley, the former U.S. energy economist for BP and current Fellow at Baker Institute, noted, “a pipeline can only go to where the pipeline ends, a liquefied natural gas tanker can literally stop in the middle of the ocean and turn around and go anywhere in the world that has the capacity to receive it.”[5] Yet, the U.S. is only as connected to the world market as long as its LNG capacity is not fully tapped out and there is spare capacity to push more supplies into the marketplace. This additional supply capacity acts as a bargaining chip for potential buyers and connects domestic prices with international benchmarks, with supply ultimately going to the highest bidder.

At least a hint of this connection occurred last year as U.S. natural gas spot prices for delivery in the Gulf rose to their highest level since 2008, averaging roughly $6.50/MMBtu or more than three times higher than the recent lows recorded in 2020. Daily price swings ranged from $3.50/MMBtu upwards to nearly $10.00/MMBtu, with the CME futures contract recording the highest level of daily volatility since its inception in 1991.[6] The European linkage was more apparent this past winter in New England, with prices rising to new record levels as a result of pipeline constraints and increased competition for LNG. Our records indicate that natural gas spot prices near Boston peaked in December around $35.00/MMBtu, as Northeast buyers outbid their Asian and European counterparts to sustain a continued flow of LNG imports.[7]

While true competition last year was fleeting, we expect to see greater ties later this decade as the next buildout introduces greater spare capacity to the system. Growth in U.S. LNG capacity, in turn, will lead to growing interconnectedness between previously regionally disconnected markets – in essence, an expanded land bridge to domestic resources. This new connectivity will ultimately lead to a situation where events in one market in the world will more strongly influence outcomes in other markets.[8]

Buffers that Kept America’s Natural Gas Price Fluctuations at Bay Have Receded

For the better part of the past three decades, consumers have benefitted from the fuel competition between natural gas and coal. It meant reliable, affordable electricity was available in many regions of the country.

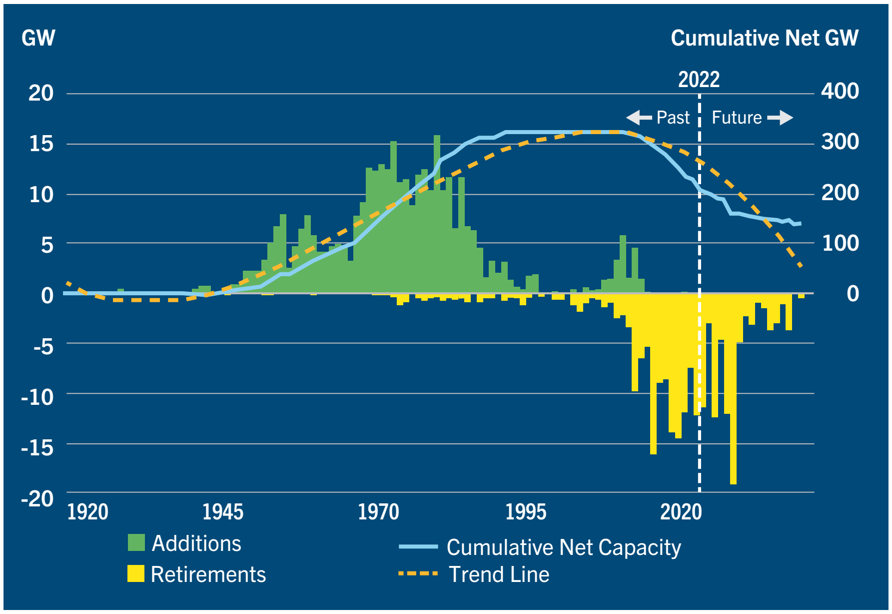
What Happens When Coal Retirements Outpace Replacements

Executives from Dairyland Power, a G&T cooperative serving half a million people in the upper Midwest, say that the next tranche of coal plant retirements would likely prove the hardest to manage from both a reliability and affordability standpoint.[9] And, they are not alone in this assessment.

The 2022 Long-term Reliability Assessment released by the North American Electric Reliability Corp. (NERC) last December highlighted that the Midwest projected capacity shortfall continues to accelerate as “older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.” While the country’s growing ‘replacement gap’ will be experienced most acutely in MISO’s territory, those same risks ripple westward into SPP and beyond.

The reliability risks associated with the country’s growing fuel dependence on natural gas may be the bigger issue, especially given the growing number of forced thermal outages related to physical natural gas flow interruptions.[10] Most recently, PJM (the nation’s largest U.S. grid operator) saw almost one-fourth of power plants shut down during the Christmas 2022 weekend storm, with the vast majority of these resources being gas-fired units. Relatedly, federal regulators concluded that natural gas-fired generators made up 58% of all unplanned outages, derates or failures to start during Winter Storm Uri in February 2021.[11]

EXHIBIT 2: U.S. Coal Capacity Additions and Retirements by Year, GW



Source: Hitachi Energy, with permission from Kent Knutson

The market impact of electric power fuel-switching has diminished and structural changes are now driving more pronounced price movements for natural gas. Charlie Blanchard, author of the book "The Extraction State: A History of Natural Gas in America" and senior analyst at Mercuria Energy Group, observed, "not only do we not have the coal plants that burn coal and make electricity, we don't have the coal itself even for those plants that are still around."[12]

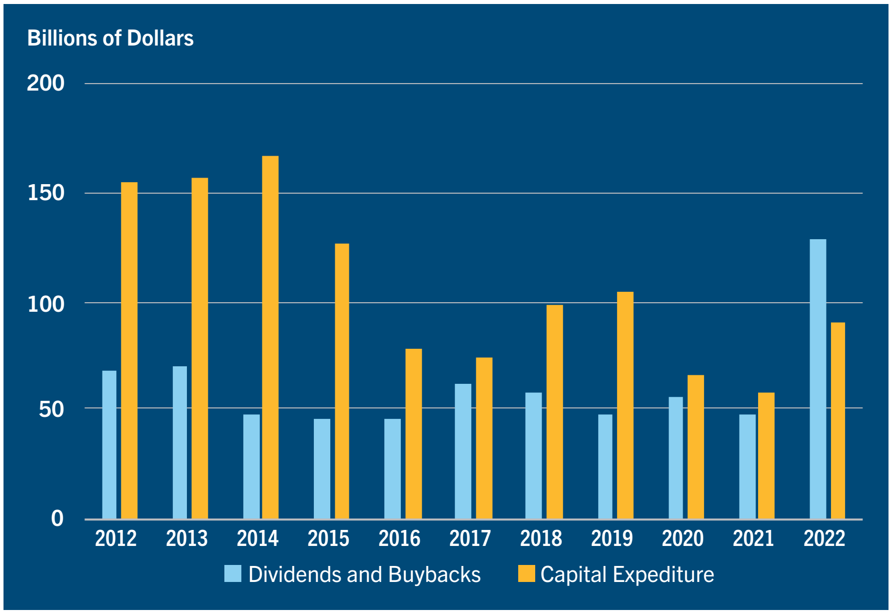
As circa 1970s and 1980s U.S. coal plants have aged and faced competitive pressure from low-cost natural gas and expansive emissions regulations, about one-third of the capacity has been forced into early retirement. From 1985 through 2014, U.S. net operating coal capacity exceeded 300 gigawatts (GWs). Installed coal plants peaked at roughly 318 GWs of operating generating capacity in 2011 and have been on a downward trajectory since *(Exhibit 2)*.

It appears that another one-third of this capacity is at risk of closing by 2030. From a starting point of roughly 200 GWs of operating capacity in 2023, utilities will retire 51 GW of coal power by 2027, with a "record plunge" of more than 23 GWs to close in 2028. Of the slated coal plants projected for retirement by 2030, over 40% are due to the Inflation Reduction Act, making coal less competitive than other resources, according to research by S&P Global.[13]

The U.S. coal fleet generated roughly 50% or more of the nation's electricity until about 2007. In 2012 that contribution fell to 37% and to just 19.5% a decade later. After briefly recapturing market share in 2021, there was some expectation that coal-fired generation would make a greater comeback in 2022, with higher natural gas prices. This didn't occur because the subset of coal units most price sensitive to fluctuating gas prices has mostly retired. Moreover, as Charlie Blanchard alluded to, U.S. coal production has struggled to return to pre-COVID levels. Despite record coal prices last year, the fall-off in U.S. mining investment and, more recently, workforce shortages and transport bottlenecks hampered a greater response to last year's record prices. Consequently, what's left is coal generation that is much less affected by swings in the competitiveness between coal and natural gas pricing.

Looking forward, S&P Global sees coal-fired power accounting for just 10.4% of electricity generation by 2030. This means that this next wave of coal retirements will usher in an even tighter connection between electricity prices and the price of natural gas. With so much of the U.S. coal fleet retired or retiring, there is simply too little elasticity left in the system to damp down natural gas price spikes. Certainly, the eroding price protection afforded by fuel substitution was a point brought home this past winter with rising electricity bills directly tied to rising natural gas prices. As long as domestic supply remains readily available and flowing, this growing dependency doesn't pose a particular risk to reliability or affordability for electricity consumers.

EXHIBIT 3: Oil and Gas Company Returns Exceed Reinvestment for First Time in at Least 10 Years



Source: Bloomberg data from S&P 500 BICS Energy Sector

Blame a Lack of Re-investment for Delayed Supply Response

Can U.S. natural gas production ramp fast enough to meet the simultaneous, accelerated growth of exports and electric generation beginning in 2025? The answer would undoubtedly been a resounding "yes" a decade ago. Now it's not so clear.

Roughly a dozen years ago, the combination of new hydraulic fracturing and horizontal drilling into shale enabled the U.S. to surpass the oil and gas production record established in 1973. Yet, this technology breakthrough ("fracking"), which resulted in a near doubling of U.S. production, would not have occurred without the massive mobilization of capital. Perhaps the biggest obstacle now to future growth will prove to be reinvestment in the resource base as well as the delivery system.

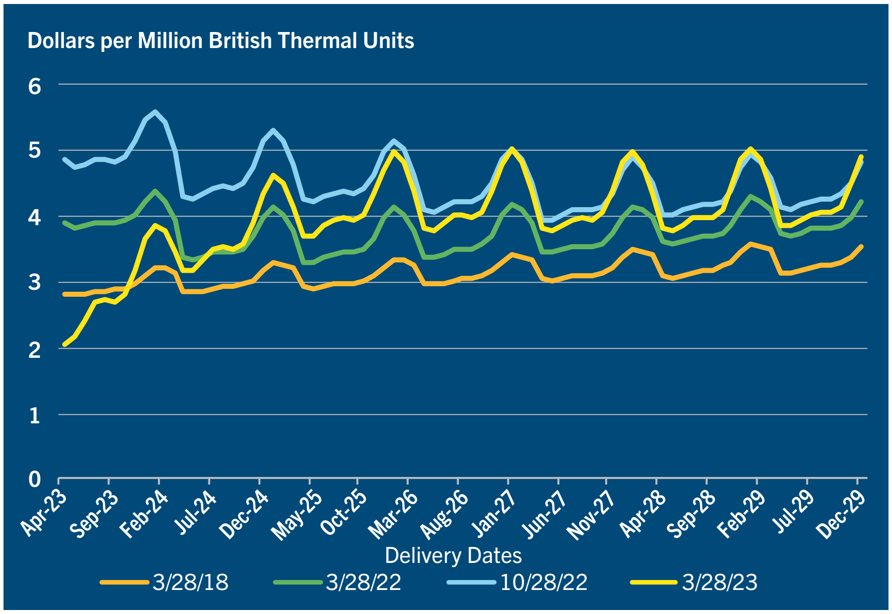
The problem: Until recently, fracking has simply not proved a great investment.[14] Many shale operators consistently outspent cash flows, burning through hundreds of billions of dollars to fund the past two decades of growth. Production rose, but lack of returns sparked an investor exodus that has yet to meaningfully reverse. Investment in oil and gas peaked last decade, with investment now anchored at more than 45% below the 2014 peak.

The industry has always gone through cycles of boom and bust. But, today the situation might be different as energy transition places an even greater emphasis on short- rather than long-term returns.[15] According to Bloomberg, for the first time, U.S. producers spent more on share buybacks and dividends last year than on capital projects, underscoring the change in priorities *(Exhibit 3).* Indeed, prioritizing returns as opposed to untapped reserves has made the sector the S&P's best performer for the past two years[16] – but at the expense of future growth.[17] What's more, even if the funding were available, The Wall Street Journal reported last year that U.S. producers would exhaust their best inventory in a handful of years if they resumed the breakneck drilling pace of the pre-pandemic era.[18]

We are reminded of the investment advice that "past performance is no guarantee of future results," as rising governmental spending on transition creates uncertainty for hydrocarbon demand and the more generalized perception of a shortened life cycle for these projects. The change in investor opinion is perhaps best expressed by the recent dearth of pipeline development. Last year, the least amount of new interstate natural gas pipeline capacity came online since EIA began data collection in 1995 and this year is shaping up to see even fewer additions.

Because much of the regulation and legal opposition has been focused on large interstate transmission pipeline projects, these projects are just not moving forward as they did a decade earlier. Instead, intrastate projects

EXHIBIT 4: U.S. Natural Gas Futures Curve (Select Dates)



Source: CME Group

in Texas and Louisiana have shouldered the burden of meeting the rising export requirements. Consequently, the basins closest to Gulf-based LNG facilities – namely, Permian and Haynesville – represent about 70% of natural gas production growth over the past five years, given the takeaway capacity limits for more remote resources.[19] Further, new restrictive policies and pushback from the insurance industry might perpetuate this gridlock. [20]

All told, the lack of reinvestment both upstream and midstream poses a real obstacle for a meaningful supply response to high prices.

Conclusion: The Solution May Be Old School Hedging

Given the recent free fall in prices *(Exhibit 4)*, it would be easy to consign last year's run-up as a blip in the context of historically tight balances.[21] This, in our opinion, would be a mistake as we believe that the run up caused by last year's scarcity concerns related to exports will be revisited several times this decade and continue to play an outsized role in setting domestic prices.[22] Moreover, the buffers customarily used to temper natural gas price blow-outs – namely, power plant fuel-switching and/or ramping domestic production – will increasingly prove less impactful in the future. Indeed, more than a few analysts have suggested that this year and next might prove the last of the "cheap shale gas era."[23] If correct, the market would then resort to the least favorable re-balancing option for all consumers: price-driven demand destruction.

How should power and energy providers manage through future periods of scarcity? The advice of one Texas cooperative is to revive financial hedging programs but also secure adequate physical supply through firm pipeline and storage arrangements. "That gives us the ability to have that gas coming into the system when you really need it. That's really what our idea of protecting our customers, mitigating that price risk," said Charley Harrel of CoServ Gas, located in Denton, Texas. In other words, downstream wholesale consumers need to fortify that investment.

There is nothing new about physical hedging for the U.S. natural gas market. The problem is that excessive production over more than a decade diminished the value of these instruments. We would argue that it is time to dust off that playbook. U.S. natural gas hedging became common in the 1990s and early 2000s when prices fluctuated widely. Since then, the surge in U.S. shale gas production caused prices to bottom out, discouraging consumer hedging activity. Yet, as we discussed, there are key structural changes in the marketplace that merit a closer review of current price risk practices. At the end of the day, the cure to high prices might ultimately rest with the consumer.

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[1] "The global energy crisis pushed fossil fuel consumption subsidies to an all-time high in 2022," *IEA,* 16 Feb. 2023. Countries shelled out a record $1 trillion to shield consumers from rising energy prices triggered by Russia's invasion of Ukraine – doubling the 2021 energy subsidies, which was roughly five times the amount paid in 2020.

[2] "Energy security and the risk of disorderly change," *IEA,* Oct. 2021. "Investing in Oil and Gas Transition Assets En Route to Net Zero," *Columbia University, Center on Global Energy Policy,* 23 March 2023.

[3] Zaretskaya, Victoria. "Europe was the main destination for U.S. LNG exports in 2022," *eia.gov,* 22 March 2023. 64% of total U.S. LNG exports were destined for the European continent in 2022.

[4] "US LNG's $13bn boost," *Financial Times,* 21 March 2023. U.S. LNG export capacity stood at about 87mn tonnes/year at the end of 2022, by the end of 2027 it will be more than 150mn tonnes/year.

[5] "Rising Natural Gas Prices Prompt Utilities to Think Globally, Act Locally," *CoBank Power Plays podcast,* 30 Nov. 2022.

[6] Lee, Jinjoo. "Natural Gas: Fasten Your Seat Belts – the buffers that keep America's natural-gas price fluctuations at bay are eroding," *The Wall Street Journal,* 11 Feb. 2023. Natural gas futures reflect similar volatility with the CME exchange recording the greatest number of 10% or greater days since the contract's inception in 1991.

[7] Robinson, Therese. "New England Natural Gas Prices Soared in 2022 Amid Stiffer Global LNG Competition," *Natural Gas Intelligence,* 20 January 2023. See ISO-NE, "Natural Gas Infrastructure Constraints". Because New England lacks sufficient take-away pipeline from domestic production basins, LNG imports must backfill the gap during peak winter months. On peak demand days, LNG contributes up to 35% of the region's gas supply.

[8] Medlock III, Kenneth B. "LNG, Globalization, and Price Volatility: Understanding the Paradigm Shift," *bipartisanpolicy.org,* March 2019.

[9] "Nuclear Power 2.0: Is a Renaissance on the Horizon?" *CoBank Power Plays podcast,* 25 Jan. 2023.

[10] Freemana, Gerad M. et al. "What causes natural gas fuel shortages at U.S. power plants?," Carnegie Mellon Electricity Industry Center Working Paper CEIC-19-03, *www.cmu.edu/electricity*, Dec. 2020.

[11] "The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report," *ferc.gov,* 16 Nov. 2021. This analysis found that a combination of freezing issues (44.2%) and fuel issues (31.4%) caused 75.6% of the unplanned generating unit outages, derates and failures to start. Natural gas fuel supply issues were caused by gas production declines, with 43.3% said caused by freezing temperatures and weather. Another 21.5% were caused by midstream, wellhead or gathering facility power losses, which could be attributed either to rolling blackouts or weather-related outages such as downed power lines, according to the report.

[12] IBID 5.

[13] Kuykendall, Taylor et al. "Inflation Reduction Act to accelerate US coal plant retirements," *S&P Global*, 10 Feb. 2023.

[14] "The great compression: Implications of COVID-19 for the US shale industry," *Deloitte Research Center for Energy & Industrials, 2020.* Deloitte estimates that, "the US shale industry registered net negative free cash flows of $300 billion, impaired more than $450 billion of invested capital, and saw more than 190 bankruptcies since 2010."

[15] "Investing in Oil and Gas Transition Assets En Route to Net Zero," *Center on Global Energy Policy at Columbia University, School of International and Public Affairs*, 2 March 2023. "Despite current record profits, private oil and gas companies' focus on capital discipline … seems to go beyond compensating for the lackluster returns of the past few years, and instead reflect adjustments to policy signaling about phasing down oil and gas production. The oil and gas industry is investing less than what is required to meet current demand trends but more than what is needed in the net-zero scenario."

[16] "Early Innings of a Potential Multiyear Bullish Energy Market," *Goldman Sachs Asset Management*, Jan. 2023. Strong performance for energy equities over the past two years has brought the weighting in the S&P 500 from 2% in 2020 (lowest level in decades) to more than 5%.

[17] "What the end of the US shale revolution would mean for the world," *Financial Times*, 15 Jan. 2023.

[18] Eaton, Collin. "Oil Frackers Brace for End of the U.S. Shale Boom," *The Wall Street Journal*, 3 Feb. 2022.

[19] Moore, Daniel, and Maya Earls. “Mountain Valley Pipeline's Up-And-Down Legal Journey: Explained,” *Bloomberg Law,* 26 Jan. 2022. The opposition to interstate transmission projects implies that the largest regional contributor to overall supply, the Appalachia, will likely see little to no production growth in the future. The article notes the Appalachian pipeline projects canceled since 2020: The 116-mile PennEast Pipeline from Pennsylvania to New Jersey; the 600-mile Atlantic Coast pipeline from West Virginia across Virginia and into North Carolina; and the 121-mile Constitution pipeline, which would have traveled from northeast Pennsylvania to central New York.

[20] “FERC Updates Policies to Guide Natural Gas Project Certifications,” FERC news release, *ferc.gov*, 17 Feb. 2022. FERC's new policy for considering projects' climate change impacts along with guidance released in January will impose new regulation on siting and building these projects. Further, Swiss insurance giant Chubb Ltd. said it will stop writing insurance policies for oil and gas extraction projects that do not have “evidence-based” methane reduction plans. For more, see “Interstate Natural Gas Pipeline Siting: FERC Policy and Issues for Congress,” *Congressional Research Service,* 9 June 2022.

[21] “Short-Term Energy Outlook Supplement: Market Drivers and Other Factors Affecting Natural Gas Prices”, *EIA,* Feb. 2023. Notably, prior episodes of tightness were marked by insufficient supply in the face of strong, mostly weather-driven domestic demand. Now, exports are playing a more significant role in price formation.

[22] CME Group. Taking a snapshot of the U.S. futures curve before and after the Russian invasion would seem to support this thesis. The acceleration investment that has occurred in financing the next wave of U.S. LNG capacity has lifted deferred futures prices above $5/MMBtu, whereas the long-dated curve had been priced between $3 and $4/MMBtu.

[23] Nasta, Sheetal. “The Final Countdown, Part 2 - RBN's Five-Year Natural Gas Market Outlook,” *RBN Energy daily blog*, 12 Feb. 2023. “After a slowdown in 2022-23, LNG export capacity additions will come fast and furious over the next several years. As they do, they will outpace production growth, which will increasingly depend on pipeline and other midstream expansions. In other words, 2023 will be the last aftershock of Shale Era surpluses.”

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