Natural Gas Producers: Why Don't You Stay?

BCE
BAYOU CITY ENERGY

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Introduction

Deep in my soul, I've been so lonely
All of my hopes fading away
I've longed for love like everyone else does
I know I'll keep searchin' even after today
So there it is girl, I've said it all now
And here we are babe, what do you say?

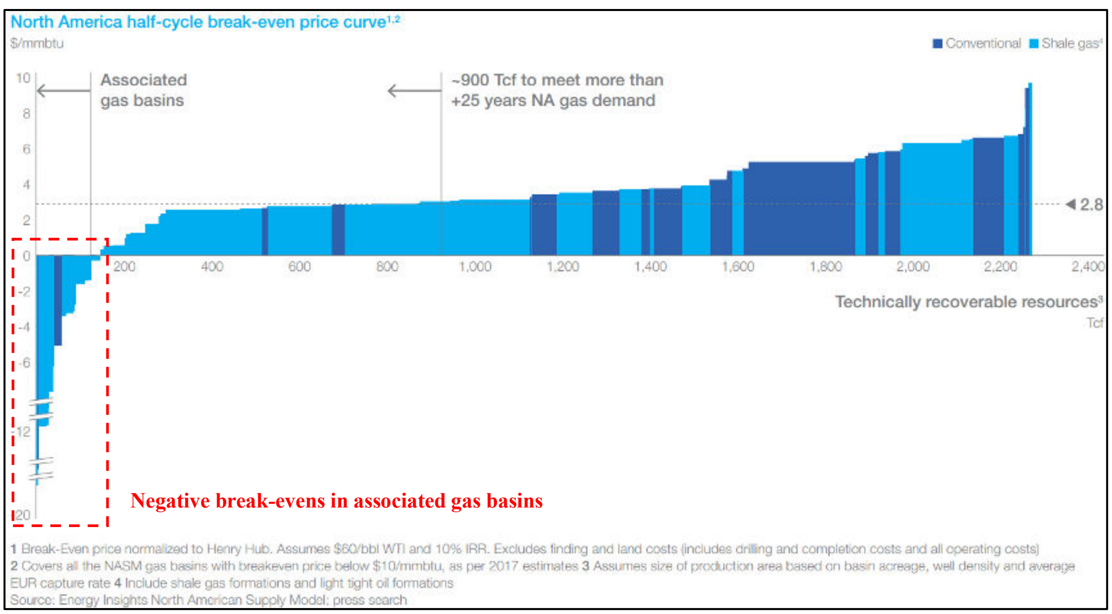
We've got tonight
Who needs tomorrow?
We've got tonight, babe
Why don't you stay?

We've Got Tonight, by Bob Seger

To our friends in the pure play natural gas production industry: *why don't you stay*? **Stay** with the strategy of capital discipline that helped US E&P to be the #1 performing S&P 500 sector in 2022. **Stay** with the strategy of returning value to shareholders and generating free cash flow. That's the love capital allocators long to receive.

Although this winter's mild weather exacerbated the drop in gas prices, the more significant cause of the current miserly price (below $2.00/Mcf) is a structural change in where natural gas production growth is occurring. The gas-supply dispatch curve (Figure 1), though slightly dated, is directionally illuminating:

Figure 1[1]



[1] *Source: McKinsey North American Gas Perspectives, June 2018. Associated gas basins are defined as those which are predominantly oil-producing basins.*

Simply put, the cost to produce *associated gas* is zero or negative. Associated gas volumes represent the lowest-cost breakeven molecules to produce today.

On the other hand, the producers in dry-gas basins have a much higher marginal cost for natural gas molecules—despite their repeated claims of owning the lowest breakeven natural gas molecules; they do not.

As of 3/4/2024, Henry Hub natural gas prices are $1.92/Mcf and the 2024 strip is $2.56/Mcf, down 26% and 27%, respectively, from only 6-months prior. These prices are low enough to eliminate any meaningful shareholder return for the foreseeable future in the dry gas producer space but have yet to persuade these producers to idle most of their drilling rigs. Their hopes for endless LNG expansion, enormous future electrification requirements, and sudden coal displacement are used as corporate rationale to continue growing gas supply, even to the tangible detriment of near-term profits and shareholder returns.

Why do these companies decide to risk destroying capital by drilling and completing structurally disadvantaged wells? Is there a basic misunderstanding of the gas supply dispatch curve? Too much "hopium" being taken with respect to gas prices? Or is it simply a stubborn reluctance to acknowledge that their recent strategies pursuing gas-weighted mergers and development opportunities was the wrong decision? It's probably a bit of all three, but we (the US oil and gas industry) need to be held accountable.

It's imperative to recognize, as the chart above shows, that dry natural gas basins produce the marginal gas molecule, not the lowest cost gas molecule. **This fact is the primary focus of our White Paper.**

As such, BCE's Call to Action for the dry gas producers is to immediately and materially drop rigs and defer completions. Doing so will allow them to reestablish meaningful free cash flow, reduce debt, return money to shareholders, and pursue M&A opportunities with more liquids-rich producers.

Why Does BCE Care?

BCE strives to be a good steward of its investors' capital. We further advocate for responsible production and strategies that benefit the oil and gas sector as a whole. With public trading multiples at depressed levels, our industry must attract new investors as well as draw cynical investors back to our space. The E&P space attracts generalist investor attention when we are profitable, and disposes of it when we are not. **For most upstream companies, BCE believes that profitability is a choice.** And when our industry (or a sub-sector of it) chooses to prioritize things other than profitability, BCE, as a multi-billion dollar AUM private equity firm in the upstream space, believes we must call-out behavior that does not advance the financial interests of the shareholders, act as an advocate for change, and offer solutions that are practical and readily adoptable.

We know that these producers play an exceptionally vital role for our society's well-being – but that role's importance needs to be rewarded financially and can only be done so with better operating behavior.

And lastly, a little bit about us, BCE is a private equity firm formed in late 2015 focused on investing in assets in "out-of-favor" basins. Our core strategy focuses on acquiring assets at attractive entry valuations, consolidating where applicable, and growing our asset base through *measured* re-investment of cash flow. BCE has ~$2.0 billion AUM as of 9/30/2023 across three funds, has completed 27 asset purchases, and has made distributions to our LPs for the last 21 quarters in a row. **BCE is consistent in its prioritization of free cash flow—and it has worked.**

Since 2016, the firm's investments have resulted in a net annual cash yield of 13.4%[2]. The dividend yield for the gas producers over the same time period is <1%[3].

On 10/25/2023, BCE took Mach Natural Resources ("MNR"), our largest investment to date, public at $19.00/share. On 2/15/2024, MNR announced its Q4 2023 distribution of $0.95/unit. This distribution implies a Q4 2023 annualized dividend yield of 20.1% for MNR, while the average Q4 2023 annualized dividend yield for the gas producers is 1.4%. The total return (stock price appreciation + distributions) since MNR's IPO date is 4.4% vs (6.1%) for the average gas producer.

Figure 2

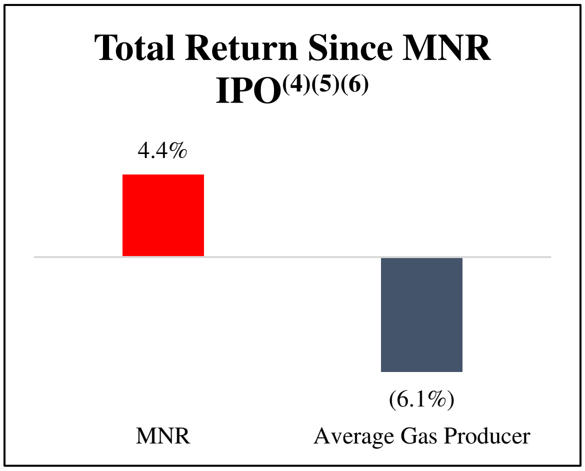
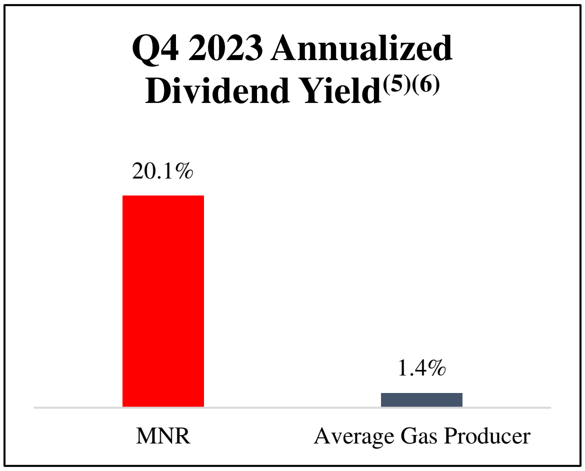


Figure 3



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[2] *The annual yield represents a cash-on-cash yield from 1/1/16 through 9/30/23. Based on BCE Net DPI as of 9/30/2023. Net DPI reflects the deduction of Management Fees, Partnership Expenses, Carried Interest and other expenses borne by investors.*
[3] *Gas Producers dividend yield represents cumulative average quarterly dividend yield from Q1 2016 through Q3 2023 (CHK and GPOR only included in quarters where they were publicly traded).*
[4] *Includes announced Q4 2023 distribution; measures stock price performance from MNR IPO date (10/25/2023) to 3/4/2024.*
[5] *For purposes of this paper, BCE has defined the dry gas producer comp set as those producers with <5% of their production producing oil, which includes AR, CHK, CNX, CRK, EQT, GPOR, RRC, and SWN. A detailed comparable analysis on these producers can be found in the Appendix.*
[6] *Share price as of 3/4/2024.*

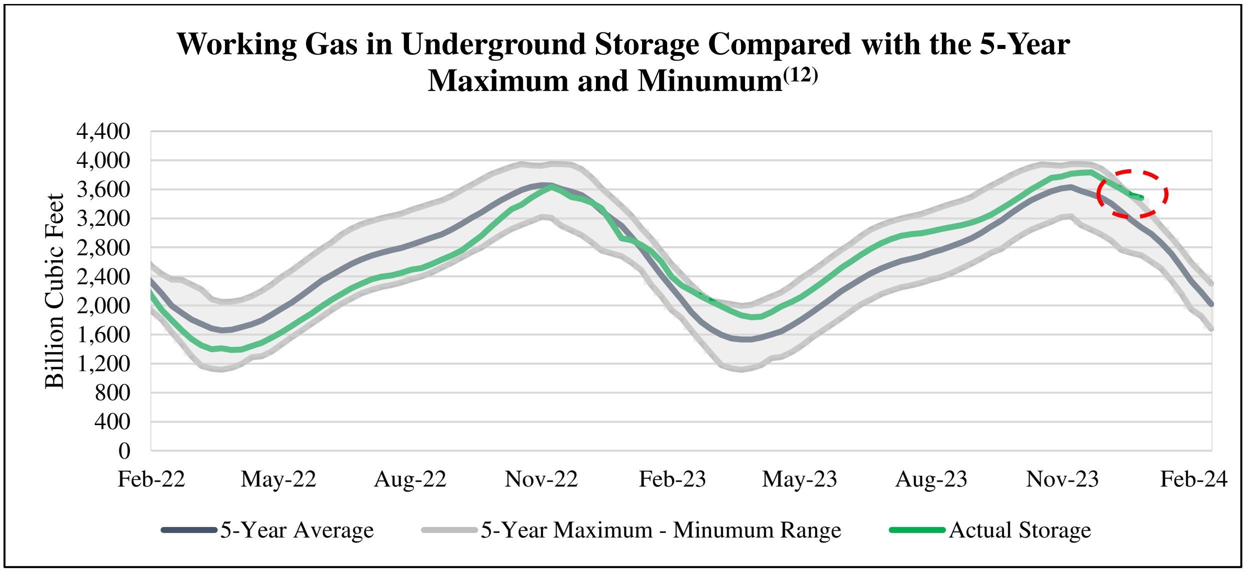
Gas Oversupplied, Growth Unjustified

Domestic Natural Gas Supply and Producer Behavior

To state the obvious, natural gas prices are in the tank, inventories are at above-average levels, and supply is abundant. As shown in Figure 4, inventory levels now exceed historical five-year averages—and have for the past 12 months. Several factors have contributed to this oversupply, including, but not limited to:

- Increased domestic production from the predominantly gas basins (December 2023 +5% YoY)[7]
- Increased domestic production via associated gas from oil basins (2023 +10% YoY)[8]
- Increasing Gas-to-oil ("GOR") ratios in the Permian Basin's key oil plays (+55% since 2013)[9]
- Lower than expected demand due to an unusually warm winter (working gas in storage 16% greater than the 5-year average[10] as of February 2024)
- "Fits and starts" nature of consistent LNG export growth
    - Operational issues (Freeport)
    - Delayed commissioning (Golden Pass)
    - Regulatory uncertainty (Biden LNG pause threatens at least a dozen project proposals in line for review at the DOE)[11]

Figure 4



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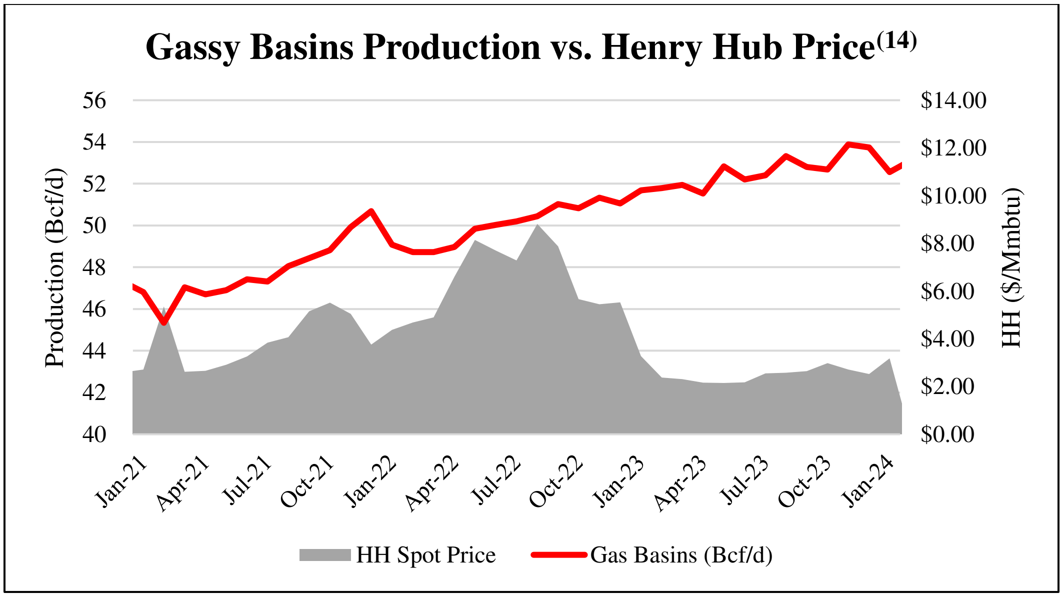
[7] *Source: EIA Drilling Productivity Report, February 2024; Predominantly gas basins are defined as the Haynesville and Appalachia basins.*
[8] *Source: EIA Drilling Productivity Report, February 2024.Oil basins include the Anadarko, Permian, Eagle Ford, Niobrara, and Bakken.*
[9] *Source: EIA, December 2023. Three key oil plays include the Spraberry, Wolfcamp, and Bone Spring.*
[10] *Source: EIA, February 2024.*
[11] *Source: Hart Energy, March 2024.*
[12] *Source: EIA.*

After a strong pricing environment in 2022 (Henry Hub spot prices averaged $6.45/MMBtu), front-month Henry Hub futures averaged $2.53/MMBtu in 2023. In mid-February 2024, front-month Henry Hub futures hit their lowest level in over 30 years (inflation-adjusted)[13], with only modest recovery since. Producers have had ample time to adjust to the reality of an oversupplied market, but as a group, they instead continue to grow volumes regardless of price, and only some have decided to partially slow down production operations (Figure 5).

Figure 5



Analysis of Recent Actions by Specific Dry Gas Companies:

Since the collapse of natural gas prices through mid-February, most of these producers have released their 2023 year-end results along with guidance for 2024, including capital spending and development plans. Some have taken a small step in the right direction by cutting rigs/frac crews immediately or announcing that they will do so in the first half of 2024. AR, CHK, CRK, and EQT announced they were cutting rigs in early 2024 or have already taken steps to do so. On the surface, these producers are moving in the right direction; however, we believe the announced cuts are insufficient to address the underlying issue in the natural gas markets.

The one-day stock price reactions following these announcements for AR and CHK, +11% and +8%, respectively, showcase how much the markets appreciated the reductions to capital expenditures in the current pricing environment. CRK and EQT were both down slightly after their announcements because we believe the announced cuts were not deep enough. Other causes could be that CRK is highly leveraged at 2.9x Net Debt to LTM EBITDA and had the highest 2023 Reinvestment Rate of the peer group at 154%. EQT (at the time) made no commitments to reduce volumes.

The **most appropriate response** to the low pricing environment came from CHK, dropping a rig and frac crew in both the Haynesville and Marcellus, decreasing 2024 expected capital expenditures by ~20% and

[13] *Source: Reuters, February 2024.*
[14] *Source: EIA; Gassy Basins classified as Appalachia and Haynesville.*

announcing that total gas production is expected to be ~16% lower in 2024 than 2023. Notably, CHK also announced a DUC and deferred TIL strategy, which it says will create up to 1.0 Bcf/d of spare capacity.

CHK has stepped into the gas market as the rational actor, but the US isn't a cartel, and we need more gas producers to pursue this path, or we will only see gas oversupply perpetuated as the market foregoes the necessary medicine of slowing or ending growth in favor of over-production today plus the promise of over-production indefinitely as "spare production capacity" and DUCs loom over the outer years of the forward strip. Unfortunately, it seems any move in prompt approaching $3/MMBtu will be met with accelerated drilling.

CHK likely "confessed" to wanting to lose a little money in the future vs. lose a lot of money right now – putting them in the quadrant of the Prisoner's Dilemma where they unfortunately lose and their peers win; as evidenced, it was EQT that most materially outperformed on the news (up ~11% on the day of CHK's announcement).

When the oil markets were oversupplied, Saudi Arabia broke through the Prisoner's Dilemma, announcing self-imposed, unilateral production cuts. Saudi Arabia's leadership put a floor on crude oil prices. Although Saudi Arabia may have lost some market share, they were smart enough to realize that they can make more money at higher prices, even with less volumes. Luckily for Saudi Arabia, they had market share to spare. This small sacrifice ultimately accreted to their benefit—and to the benefit of every other oil producer on the globe.

Unlike Saudi Arabia, pure play natural gas companies in the US have to answer to someone—be it shareholders, investors, lenders, etc. No individual gas company is as dominant in the natural gas market as Saudi Arabia is on the oil market. Thus, asking either EQT or CHK *alone* to break through the Prisoner's Dilemma, like Saudi Arabia did, is too tall a request. A change in the US natural gas market is going to take an industry-wide effort of methodical capital discipline.

On 3/4/2024, EQT announced a production curtailment, reducing gross production by 1 Bcf/d until the end of March with the plan to reassess in Q2 2024. The market responded positively with front month Henry Hub up ~5% on the day and EQT up over 1%. We believe this is a step in the right direction; however, a reduction in rig count would have provided a clear commitment to recognize the fundamental issue with dry gas producers generating limited free cash flow for the foreseeable future.

By curtailing production vs. lowering their rig count, EQT is eliminating a portion of their cheapest source of revenues (already producing volumes) instead of cutting their most expensive source of revenues (new volumes from drilling/completion operations). This does not address the core issue of increasing their free cash flow conversion per additional Mcfe. As discussed, the domestic natural gas market is beginning to resemble the Saudi Arabia-regulated global crude oil market. EQT is allowing itself to be the "regulator" of the market with the optionality of bringing their "spare capacity" online.

The below table summarizes the dry-gas producers by their recent reported 2024 operational guidance. We ranked the group by who took the most directionally corrective steps by cutting production guidance with the tiebreaker going to decreasing capex guidance.

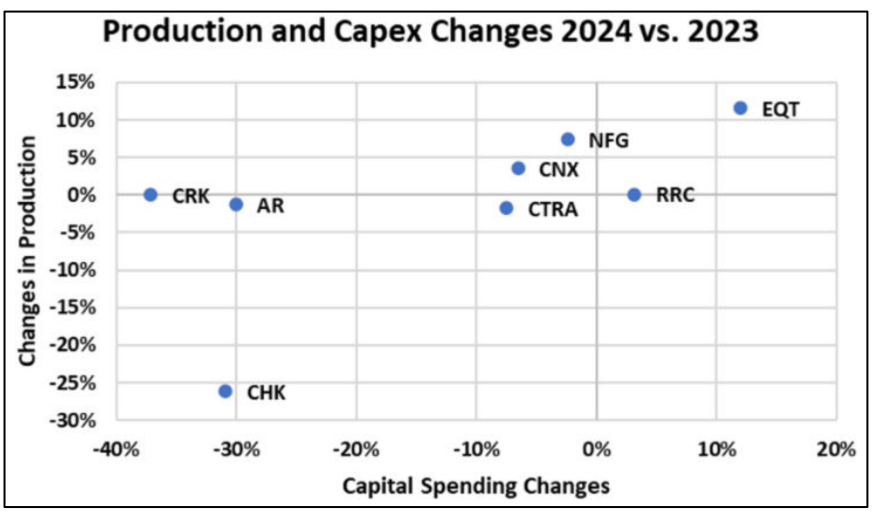
Strong Response

CHK	• 2024 production to decline by ~26% • 2024 capex ~27% lower YoY • Dropping 2 rigs and 2 frac crews (1 each in Haynesville and Marcellus) • Plan to TIL 30-40 wells in 2024 vs 134 in 2023 • Will have 1 Bcf/d in "spare production capacity"
AR	• 2024 production to decline 1.2% YoY • 2024 capex down 30%+ YoY • Recently released 1 rig (running 2 rigs and 1 frac crew) • Higher liquids content provides $1/mcf uplift to Henry Hub
GPOR	• 2024 production flat • 2024 capex ~10% lower YoY • Focusing on liquids-rich development
EQT	• 2024 production flat, including Tug Hill • 2024 capex ~4% higher YoY • Running 2-3 rigs and 3-4 frac crews • Announced 1 bcf/d production cut from late February 2024 through March
RRC	• 2024 production flat YoY • 2024 capex 5% higher YoY • Running 2 rigs and 1 frac crew
CNX	• 2024 production to increase 4% YoY • 2024 capex 12% lower YoY, driven by "new technologies group"
SWN	• No guidance
CRK	• 2024 production to decline ~4% from Q4 but increase 3% YoY • Released 1 frac crew in January 2024, dropping 2 Haynesville rigs by March • 2024 capex ~37% lower YoY • No dividend or share repurchases planned • Running 5 rigs despite balance sheet issues (2.9x Net Debt / LTM EBITDA)

Weak Response

CEOs say they always have the ability to cut more down the road… but this is a "show me" market; not a "tell me" market. Producers need to announce capex **cuts now** while presenting the option to develop their inventories later.

Figure 6[15]

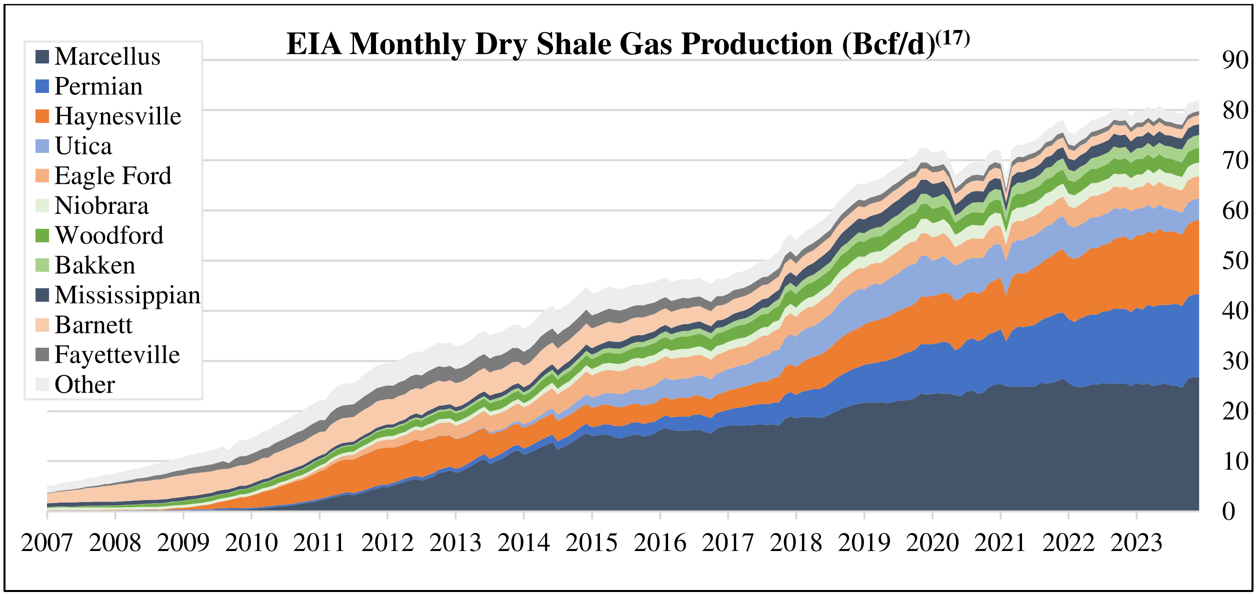


[15] *Source: RBN Energy, March 2024. This is not reflective of EQT's production curtailment announcement on 3/4/2024.*

Associated Gas Growth Could Fulfill Future Demand Growth

The Permian Basin is the second-largest gas-producing region in the country and accounts for about a quarter of total U.S. marketed natural gas production.[16] In the three top-producing tight oil plays in the Permian (Wolfcamp, Spraberry, Bone Spring), production of associated gas has nearly tripled since 2018. The Permian Basin shows no signs of slowing down its production growth, and the basin continues to timely scale its infrastructure to meet demand growth and accommodate increasing GORs.

Figure 7



Associated gas from the Permian, and other associated gas molecules, which are produced at **zero-cost**, doom stubborn dry-gas producers who refuse to react to what appears to be a long oversupply of natural gas in the Lower 48. And with natural gas demand expected to grow to ~125 bcf/d by 2028[18], the steady growth of **only** associated-gas molecules can more than likely fill this demand.

And referring back to Figure 1, the production growth data supports this marginal cost advantage for associated gas producers. Associated gas production is growing at nearly twice the rate of gas production coming from the dry gas basins. Within the prolific shale dry gas basins, the Haynesville and Appalachia, year-on-year gas production increased ~5%, growing to 52.6 Bcf/d in 2023 (+~2.5 Bcf/d vs 2022).[19] Meanwhile, associated gas production out of the traditional oil-prone unconventional basins (Permian, Anadarko, Bakken, Eagle Ford, Niobrara) increased by nearly 10% to 45.9 Bcf/d (+3.9 Bcf/d vs 2022).[19]

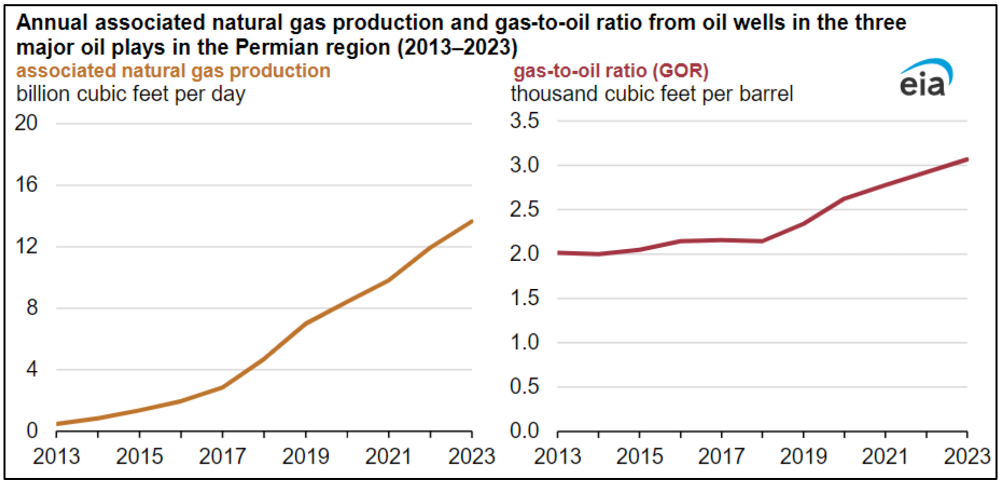
Projecting into 2025, there is a scenario where gas production from the oil basins collectively surpasses production from the dry gas plays. The demand side of the equation is equally discouraging for the pure-play gas producers. The EIA forecasts domestic gas consumption and LNG export growth at less than 2 Bcf/d for 2024 and 2025.[20] Therefore, in a world where associated gas producers are agnostic to natural gas prices, there is no reason to believe they will issue a production change in response to sub-$2.00/Mcf gas

[16] *Source: EIA, January 2024.*
[17] *Source: EIA.*
[18] *Source: RRC February 2024 Investor Presentation.*
[19] *Source: EIA Drilling Productivity Report, February 2024.*
[20] *Source: EIA, February 2024.*

(they haven't yet). It is thus BCE's belief that the onus of any production response, and the benefits / consequences of that response, falls squarely upon the gas-weighted producers[21] in the Haynesville and Appalachia basins.

The increase in associated gas production can be attributed to increases in crude oil production and increased GORs (Figure 8). **Notably, in the Permian Basin as a whole, average crude oil production in the first nine months of 2023 increased by 68% compared with 2018 levels, <u>while natural gas production increased by 104% over the same period</u>** (~23 Bcf/d in 2023 vs ~11 Bcf/d in 2018)[22].

<u>Figure 8[23]</u>



As the wells in the Permian (and other oily basins) mature, and as new development moves out further from the core, GORs tend to rise, increasing the amount of associated gas for every barrel of oil produced. As more oil is produced, the pressure within the reservoir declines, which allows more gas to be released from the formation.

Assuming the oil-focused basins continue the path of their two-year growth trajectory, they will produce ~50 Bcf/d in 2024 (~4 Bcf/d increase). As a result, production would still be several Bcf/d higher in 2024 even with an anticipated production decline from the gas basins.

<u>Figure 9[24]</u>

	Oily Basins Gas Growth	
	bcf/d	*% growth*
2019	37.2	N/A
2020	37.0	(0.5%)
2021	38.2	3.2%
2022	42.0	9.7%
2023	45.9	9.4%
2024e	*50.3*	*9.6%*

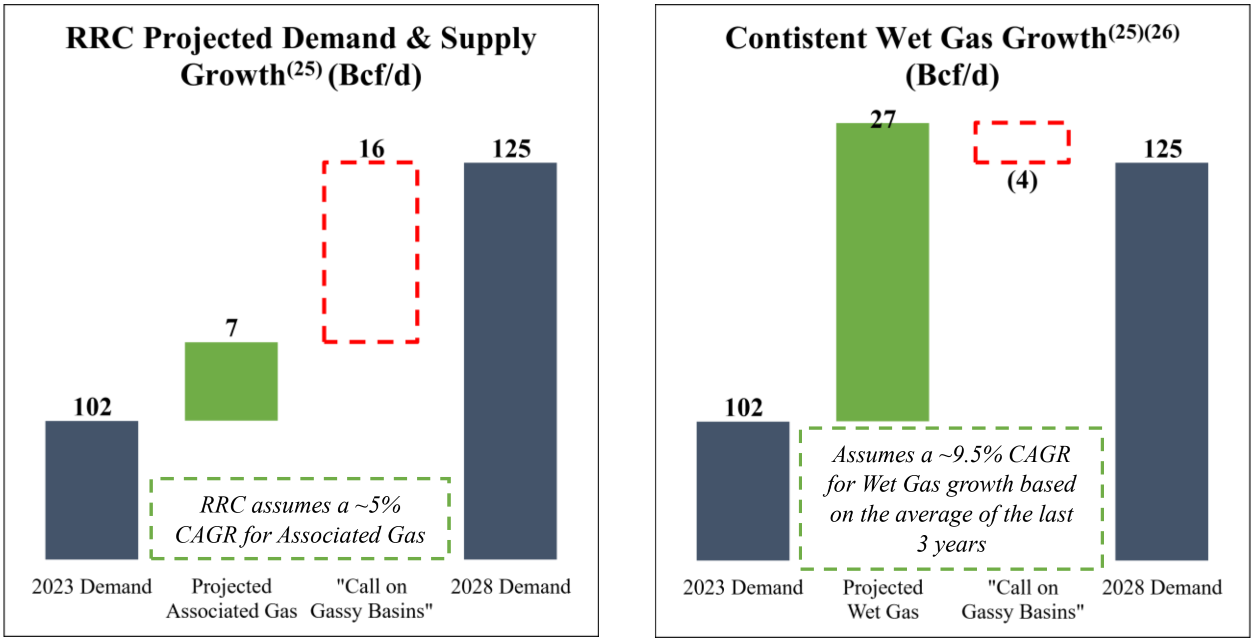
[21] *For purposes of this paper, BCE has defined the dry gas producer comp set as those producers with <5% of their production producing oil. A detailed comparable analysis on these producers can be found in the Appendix.*
[22] *Source: EIA Drilling Productivity Report.*
[23] *Source: EIA, Enverus Drilling Info.*
[24] *Source: EIA, February 2024 – reflects wet gas from oily basins (Anadarko, Permian, Bakken, Eagle Ford, Niobrara).*

Absent a material pull-back in the Permian/Bakken/EFS/Anadarko/Niobrara (oil-focused basins), a 5% year-over-year reduction in Haynesville/Appalachia (gas-focused basins) production is not enough to right size supply and won't be achieved with only one gas producer (CHK) doing the right thing.

The demand growth picture is hazy as well. The prospect of near-term LNG demand growth is not as rosy as it once was. Exports are not projected to increase by much at all until 2025 when several projects (Golden Pass, Corpus Christi, Plaquemines) come online, adding a combined ~4 Bcf/d of feedgas demand. While the Biden administration's LNG pause does not impact already-approved projects, it does threaten over a dozen projects that have yet to receive approval by the DOE. The result is that LNG demand pull has fizzled for the next 18 months, and there is a big question mark towards the latter end of the gas curve.

Figure 10 below demonstrates two different scenarios regarding demand growth and where the additional supply may be provided. The 2028 demand of ~125 Bcf/d is sourced directly from RRC's investor presentation, which implies a ~4% CAGR for gas demand growth from 2024-2028.

Figure 10



As shown above, the anticipated growth from associated gas would be more than enough to supply the market through 2028. And BCE believes that this anticipated associated gas supply growth may be materially understated so long as oil prices stay >$70/bbl WTI and GORs of the oily basins continue to increase as the plays mature.

No matter how much the gas producers advertise themselves as the "low-cost" gas producers, given proper perspective, that will never be the case. The marginal cost of supply represents the least economic unit of production needed to meet the demand curve. Dry gas producers will *always* be the marginal cost producer and *never* the low-cost producer in the face of significant associated gas supply. This reality leaves dry-gas producers at a structural disadvantage regarding the cost of production and should drive a decrease in near-term activity.

[25] *Source: RRC February 2024 Investor Presentation.*
[26] *Projected Wet Gas reflects 2023 gas from oily basins as defined by the EIA.*

Where is the Free Cash Flow?

2021 and 2022 saw a beneficial and unique trend for public energy investors – high free cash flow margins, disciplined capital spending, and significant capital returns in the form of dividends and stock repurchases. It was a sight for sore eyes and generated significant positive coverage around the energy sector (which had been ignored for the previous five years or so). There seemed to be momentum in the energy public equities, with generalist investors taking notice.

Investors expected the trend to continue into 2023. The market had been told these companies shifted their strategies to "capital discipline" for good and would continue to return cash to shareholders despite a low pricing environment. However, as natural gas prices dropped precipitously, capital spending remained the same, and free cash flow suffered as a result.

Median free cash flow conversion (FCF / Mcfe Production) amongst the dry gas producers was \$0.26/Mcfe in 2023 versus \$1.21/Mcfe in 2022. Similarly, the median free cash flow conversion (FCF / EBITDA) was 17% in 2023 versus 50% in 2022. The primary reason for the decrease in free cash flow was a significant increase in reinvestment rates across the peer group. The median reinvestment rate (Capex / EBITDA) was 71% in 2023 versus 42% in 2022.

Figure 11

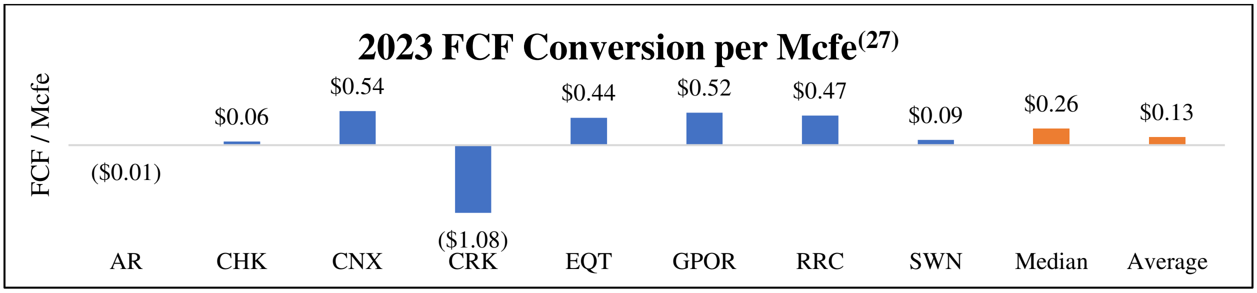
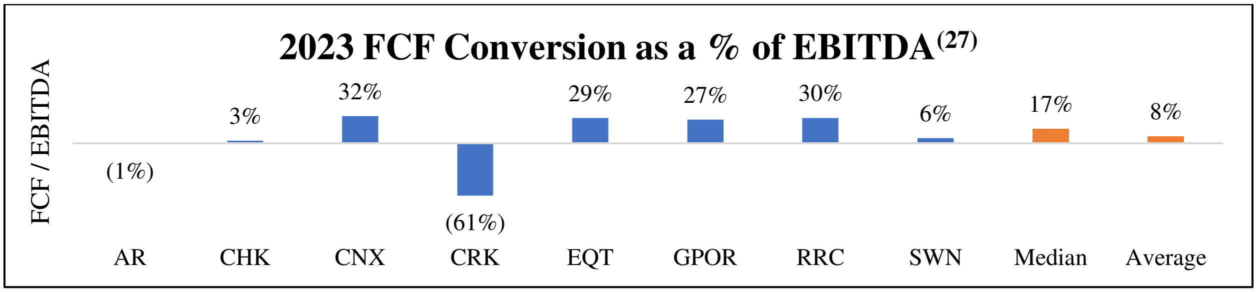


Figure 12



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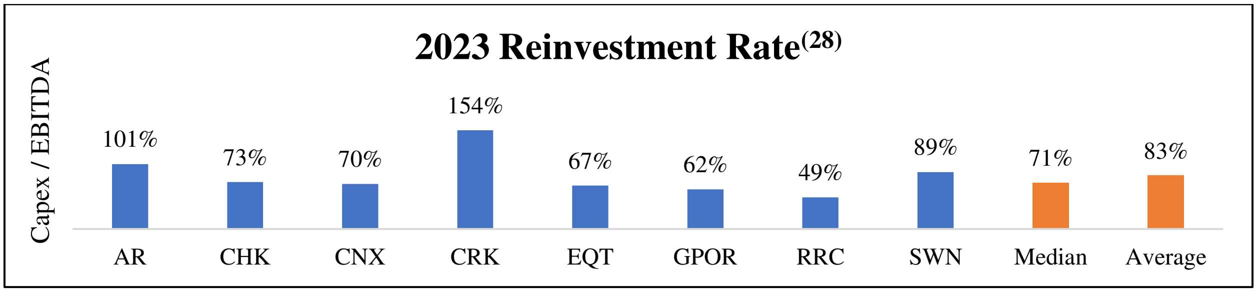
[27] *Company filings & disclosures.*

Figure 13



If natural gas price appreciation does not occur over the next year, and capital budgets are not right-sized, the producers listed above will likely incur a significant outspend during 2024.

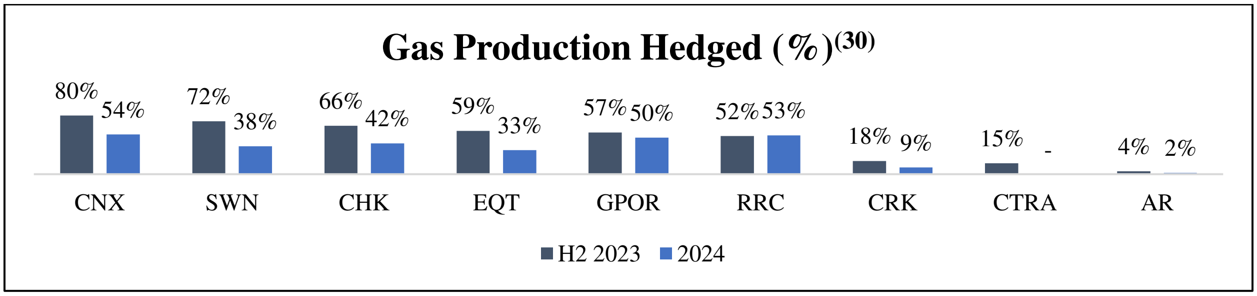
In AR's latest investor presentation, they claim to have the "Lowest 2024E Unhedged FCF Natural Gas Price Breakeven" amongst their peers at $2.27/Mcf with Haynesville operators around $3.00/Mcf. However, sustaining current activity levels throughout 2024 at a sub-$2.00/Mcf gas price implies nearly all dry gas producers would have negative free cash flow, with reinvestment rates greater than 100%. See Figure 14 below:

Figure 14[29]

	2023 Actuals			Low Gas Price Sensitivity ($2.00/Mcf)		
Company	FCF / EBITDA (%)	FCF / Mcfe ($)	Reinvestment Rate	FCF / EBITDA (%)	FCF / Mcfe ($)	Reinvestment Rate
AR	(1%)	($0.01)	101%	(143%)	($0.54)	244%
CHK	3%	$0.06	73%	(35%)	($0.47)	101%
CNX	32%	$0.54	70%	1%	$0.01	101%
CRK	(61%)	($1.08)	154%	(130%)	($1.61)	219%
EQT	29%	$0.44	67%	(10%)	($0.09)	105%
GPOR	27%	$0.52	62%	(1%)	($0.01)	86%
RRC	30%	$0.47	49%	(6%)	($0.06)	74%
SWN	6%	$0.09	89%	(49%)	($0.44)	140%

At the end of Q3 2023, the gas producers (including CTRA) had hedges in place to cover 50% of their anticipated natural gas production for the second half of 2023 at an average price of $3.35/Mcf. The group had only 30% of their 2024 production hedged as well at a weighted average price of $3.56/Mcf[30].

Figure 15



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[28] *Company filings & disclosures.*
[29] *Based on the average Henry Hub price in 2023 of $2.53/Mcf. Applies the ($0.53/Mcf) differential to each producer's average sales price to derive a proxy for revenue loss. Excludes the impact of any incremental hedge gain, decrease in production taxes, or any decrease in drilling activity due to lower gas prices. This table is intended to show the proportionate consequences of not operationally changing behavior in a $2.00/Mmbtu price environment.*
[30] *Source: S&P Global, September 2023.*

According to Fitch, the average 2024 gas hedge coverage for gas-focused producers is currently 48%[31]. The 2024 gas curve started to move down in Q4 2023, so the incremental hedges added by these producers during the quarter likely brought down their average hedge price quite a bit. By the end of 2023, the 2024 curve was below $3.00/Mcf. Ultimately, there is likely to be a massive headwind for gas derivative settlements in 2024 relative to what producers realized in 2023.

Gas Producers Cash Flow Analysis (2023)

Figure 16

	A	B	C	D	E	F	G	H
						(B+C+D+E)	(A+F)	(G/E*12)
Company	Avg. Sales Price (Pre-Hedge)	Opex ($/Mcfe)	G&A ($/Mcfe)	Interest ($/Mcfe)	D&C ($/Mcfe)	Deductions ($/Mcfe)	Net Operating CF ($/Mcfe)	Months Payback (New Wells)
Antero	$3.45	($2.42)	($0.13)	($0.10)	($0.73)	($3.38)	$0.07	128.8
Chesapeake	$2.66	($1.06)	($0.09)	($0.08)	($1.17)	($2.39)	$0.27	52.4
CNX	$2.32	($0.86)	($0.22)	($0.26)	($1.21)	($2.55)	($0.23)	NA
Comstock	$2.40	($0.78)	($0.07)	($0.32)	($2.32)	($3.50)	($1.10)	NA
EQT	$2.50	($1.21)	($0.12)	($0.10)	($0.95)	($2.38)	$0.12	95.4
Gulfport	$2.73	($1.17)	($0.10)	($0.15)	($1.07)	($2.49)	$0.24	54.6
Range Resources	$2.99	($1.61)	($0.21)	($0.16)	($0.73)	($2.71)	$0.28	31.5
SWN	$2.46	($1.20)	($0.10)	($0.15)	($1.07)	($2.51)	($0.05)	NA

Notes:

- *Each metric is based on Year-Ended 2023 data as reported in each company's 2023 10-K.*
- *Average Sales Price (Pre-Hedge) reflects the three-stream average sales price per Mcfe.*
- *Opex ($/Mcfe) includes all gathering costs, processing costs, LOE, production taxes, and exploration expense per unit of 2023 production.*
- *G&A ($/Mcfe) represents General and Administrative expenses per unit of 2023 production.*
- *Interest ($/Mcfe) reflects the Interest Expense per unit of 2023 production.*
- *D&C ($/Mcfe) reflects the Drilling and Completion Capital Expenditures per unit of 2023 production.*
- *Net Operating CF ($/Mcfe) represents the net cash flow associated with each unit of 2023 production after considering each company's operating costs and development activity.*
- *Months Payback (New Wells) represents the approximate number of months it would take to breakeven on the company's D&C costs for each new unit of production produced. NA represents a net loss on each incremental unit of production produced at current activity levels.*

Based on the analysis performed by BCE, three of the eight dry gas producers analyzed were operating at a net loss (before hedging) during 2023 despite gas prices averaging $2.53/Mcf during the year. Given the current low pricing environment, these companies will likely continue to lose money in 2024 without a substantial activity cut. The others operated at very slim margins in 2023; current pricing levels do not bode well for them either without a meaningful activity reduction.

Based on this analysis, the gas producer with the most cost-effective operations in the peer group is RRC. Due to RRC's higher liquids content, their average sales price is the second highest of the group. D&C costs per Mcfe are tied for the lowest with AR, and Opex/Mcfe is in line with peer averages, unlike their other liquids-rich peer, AR, whose Opex/Mcfe is almost twice the peer group average.

[31] *Source: Fitch Ratings, February 2024.*

Overall, value is being destroyed by producers who are 1) over-levered, 2) too aggressive with development, and 3) lacking liquids exposure.

Figure 17

	G	I	J	K	L	M	N	O
	(A+F)		(G + H)					**(J+K+L+M+N)**
Company	Net OCF ($/Mcfe) (Pre-Hedge)	Hedge G/L ($/Mcfe)	Net OCF ($/Mcfe) (Post-Hedge)	Dividends ($/Mcfe)	Share Repurchase ($/Mcfe)	Other Capex ($/Mcfe)	Debt Reduction ($/Mcfe)	**Rem. CF ($/Mcfe)**
Antero	$0.07	($0.02)	$0.05	-	($0.06)	($0.18)	-	**($0.19)**
Chesapeake	$0.27	$0.33	$0.60	($0.36)	($0.27)	($0.20)	($0.79)	**($1.02)**
CNX	($0.23)	$0.29	$0.06	-	($0.57)	($0.00)	-	**($0.51)**
Comstock	($1.10)	$0.15	($0.95)	($0.26)	-	($0.39)	-	**($1.61)**
EQT	$0.12	$0.29	$0.41	($0.11)	($0.10)	($0.05)	-	**$0.15**
Gulfport	$0.24	$0.40	$0.64	-	($0.28)	($0.09)	($0.09)	**$0.18**
Range Resources	$0.28	$0.32	$0.60	($0.29)	($0.02)	($0.06)	($0.13)	**$0.09**
swn	($0.05)	$0.21	$0.16	-	-	($0.21)	($0.30)	**($0.35)**

Notes:

- *Hedge G/L ($/Mcfe) represents the difference between the Average Sales Price including differentials and the Average Sales Price excluding differentials.*
- *Net OCF ($/Mcfe) (Post-Hedge) represents the net cash flow associated with each unit of 2023 production after considering each company's operating costs and development activity and the settlement of derivatives.*
- *Dividends ($/Mcfe) represents the dividends paid per unit of 2023 production.*
- *Share Repurchases ($/Mcfe) represents the total $ amount of shares repurchased per unit of 2023 production.*
- *Other Capex ($/Mcfe) represents all other capital expenditures other than D&C capital per unit of 2023 production.*
- *Debt Reduction ($/Mcfe) represents the net reduction in debt per unit of 2023 production. If debt increased during the period, this use of cash is shown as zero.*
- *Rem. CF ($/Mcfe) represents the remaining cash flow after considering each company's operating costs, development activity, derivates settlements, and discretionary uses of cash.*

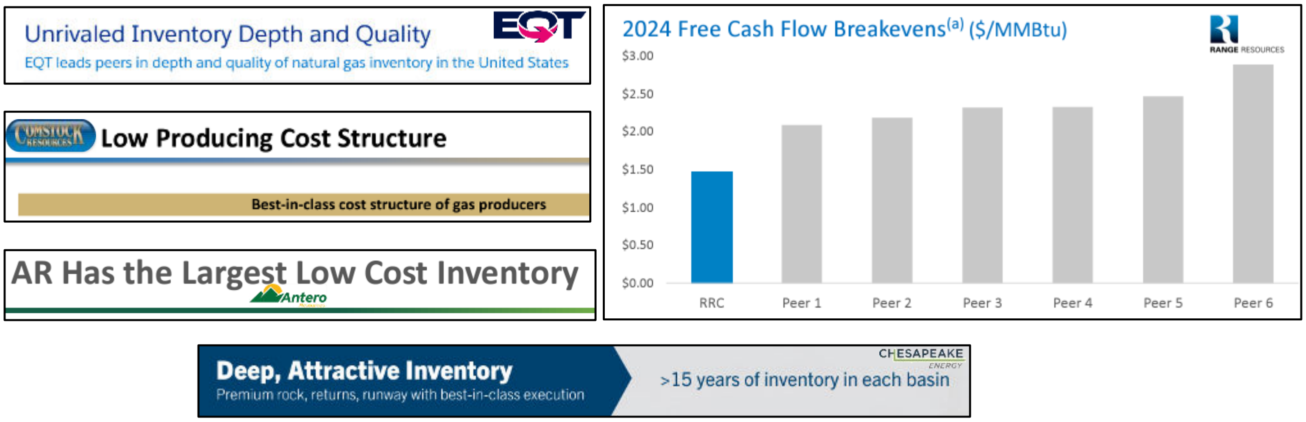
Assuming each company continues its current level of corporate hedging, capital spending, and shareholder return, only three of the producers highlighted above are breaking even on each new molecule generated through the drill-bit. EQT, GPOR, and RRC all have shareholder return plans, whether it be dividends, share repurchases, or both, and yet, they are all still generating positive value for each new molecule produced. The announced activity cuts should have a positive impact on these metrics for 2024; however, they may be offset by changes in realized prices.

Contrast that with SWN (and going forward, CRK, who is suspending their dividend), and you have two completely different stories. SWN's shareholders are receiving no return on their equity other than potential stock appreciation, and the business is losing value for every new molecule drilled.

This brings into question the effectiveness of share repurchase plans when value is being destroyed via unnecessary drilling and completion activity. Repurchase plans are only effective if the value of the business holds or increases.

We’re #1! - The ‘Best’ Inventory Fallacy

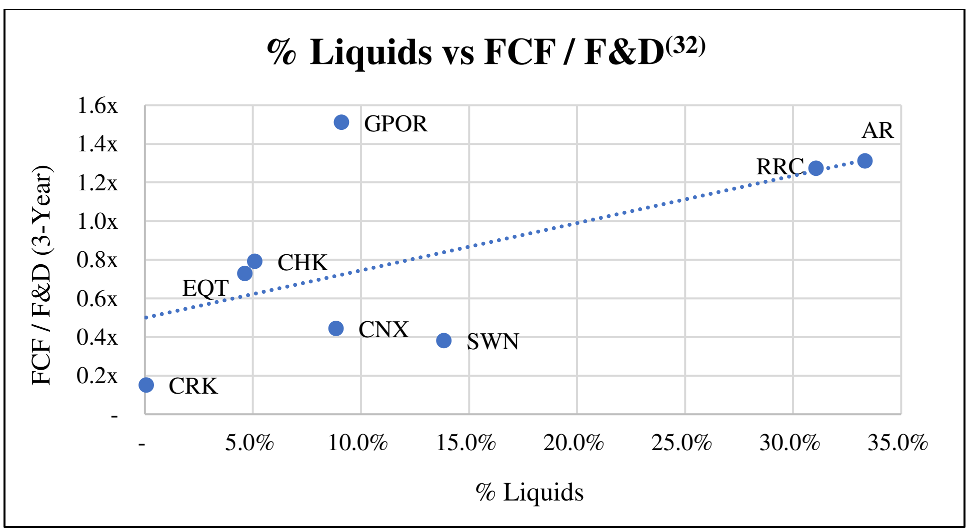
Several of the producers we have analyzed claim to be the superior dry gas producer in terms of cost and inventory quality. Snippets below were pulled directly from the dry has producer investor decks:



F&D and Inventory Conversion Analysis

We performed an F&D analysis for each of the dry gas producers to determine who is actually delivering on these claims. Overall, the producers with higher liquids content as a percent of current production tended to produce more free cash flow per dollar spent on F&D than those that had lower liquids content. This should come as no surprise – more on this later.

<u>**Figure 18**</u>



An important measuring stick for E&P companies is their ability to produce free cash flow from their drilling capital. One clear advantage to higher free cash flow is the optionality to drill for three production streams as opposed to just one. As displayed above, gas producers with more liquid rich production tend to have a better free cash flow conversion from new drilling locations.

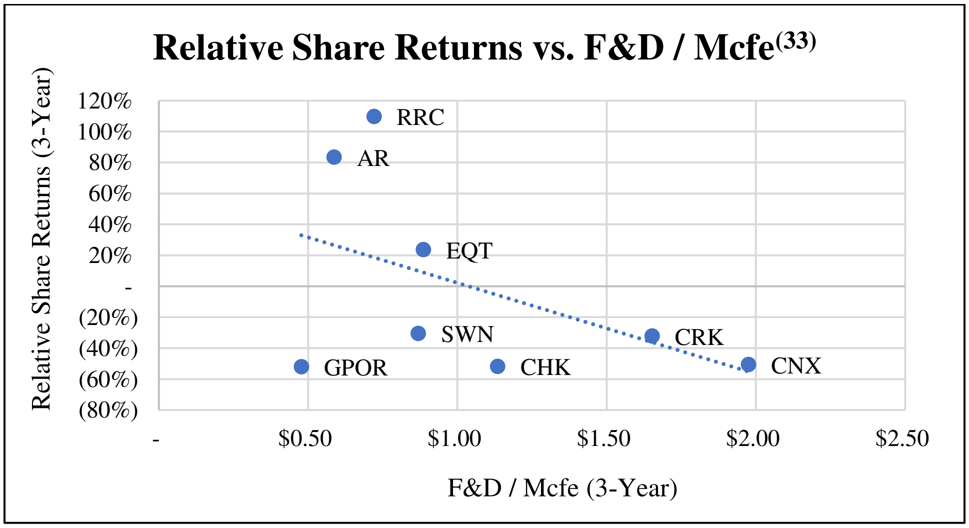
[32] *Company filings & disclosures.*

Note: 'FCF / F&D (3-Year)' is a metric derived by BCE that is meant to be a directional indicator of inventory quality, reflecting how efficient a company is at converting its reserve additions to free cash flow. Due to the variability of F&D costs, a three-year time period is used to come to a more accurate depiction of efficiency. The detailed calculation is as follows: (3-Year Average Free Cash Flow / 3-Year Average Mcfe Production) / (3-Year Total F&D Costs / 3-Year Total Mcfe Reserve Adds).

In times of low natural gas prices, having the optionality to drill more liquids-rich inventory is **an enormous competitive advantage**. In their most recent earnings call, AR touted their high exposure to liquids, which results in "the lowest unhedged FCF breakeven price among natural gas peers". Other gas peers have also highlighted their ability to re-allocate capital to liquids-rich opportunities. For example, GPOR announced they would be targeting more liquids-rich development in the Utica, Marcellus, and SCOOP. Even with 10% lower capex YoY, GPOR expects to keep its production flat and improve margins and FCF generation as a result of the re-allocation of D&C capital.

In a perfectly rational market, all else being equal, one would expect producers with higher levels of capital efficiency to outperform those with lower efficiency levels. As part of BCE's F&D analysis, we mapped out each dry gas producer's recent stock performance versus its 3-Year F&D Costs per Mcfe. Although there are many factors that impact a company's equity performance, the results were generally in line with expectations. Those with more efficient inventory conversion (lower F&D / Mcfe), generally outperformed their less efficient peers over a three-year time period.

Figure 19



Note: 'Share Returns (3-Year)' reflects the change in share price from 12/31/2020 to 12/31/2023 and the dividends issued over the same period. The returns represent the % above or below the relative average returns of the group. CHK and GPOR share returns represent the return since each company emerged from bankruptcy in 2021.

At the end of the day, each producer may have a legitimate claim to having lower costs or lower break-evens when comparing themselves to the dry gas production of other primarily dry gas producers. However, these producers are not isolated in the domestic dry gas production market. Dry gas producers' break-evens are (as shown) structurally disadvantaged when compared to those of associated gas producers.

[33] *Company filings & disclosures.*

BCE’s Call to Action

1. Reduce Drilling and Completion Activity

Even with the announced production curtailment by EQT and the activity cut by CHK, significant reductions in drilling and completion activity are necessary to provide equilibrium to the supply / demand issues the market is currently facing. There is little doubt the oily basins will continue their growth and increase natural gas supply to the market, which is why we call on the dry-gas producers to step in and reduce rigs and frac crews as soon as possible.

2. Pursue Liquids-Rich M&A

As mentioned throughout this paper, associated gas molecules are *structurally advantaged* relative to dry gas molecules. It’s simple–as companies diversify their production streams, their break-evens decline. A couple great examples of the benefits of a more diversified production stream are Antero (AR) and Coterra (CTRA); their production streams of 67%/31%/2% and 72%/14%/14% (Gas/NGLs/Oil), respectively, yielding superior metrics across the board relative to dry gas producers. Although still producing a majority gas (on a BOE level), the additional production of liquids allows these companies the commodity price optionality which has been proven highly beneficial in the volatile commodity market of recent years.

Unfortunately, it seems that these all-gas producers are only pursuing all-gas mergers. Thus far, there has been little interest from all-gas producers to find more liquids-rich dance partners because doing so would imply an admission that their recent strategic focus on all-gas assets/mergers was the wrong one (it was). Elevated trading multiples for gas producers relative to their oily peers give them more bandwidth to make accretive acquisitions regardless of the target’s commodity profile mix.

3. Set Reasonable “Best Practice Methods”

Dry gas producers need to provide a defined guide for their use of operating cash flows. Any cash flow generated should first be used to clean up the balance sheet and repay any outstanding debt so that net leverage is less than 1.5x (Net Debt / EBITDA). Then, capital expenditures should be limited to a reinvestment rate of <50% (Capital Expenditures / EBITDA). And finally, when possible, a concrete shareholder return plan should be put in place wherein any remaining free cash flow is returned to shareholders in the form of dividends or share repurchases.

Management teams should focus on developing wells that have expected production with >20% liquids content, if possible. And there should be compensation plans in place that incentivize management to adhere to all of the above-listed best practices.

4. Limit Spending in Dry-Gas Basins

For those producers that do have some access to more liquids with their asset portfolios, rather than continuing to spend capital drilling dry-gas wells at higher break-evens and worse economics, they can focus their capital activity in their liquid rich assets. As observed by CTRA’s recent earnings call, CTRA is cutting Marcellus spending by ~$435mm, while increasing spending in the Permian and Anadarko by ~$130mm and ~$155, respectively. We believe that AR and RRC can do more of the same.

Conclusion

A lot has been discussed in this White Paper, but we believe the key points to take aware are as follows:

- **The dry natural gas basins are the marginal-cost natural gas producers, not the low-cost producers. Until the industry and investors acknowledge this, categorical behavior changes will be slow/hard to come by.**
- Associated gas will continue to accommodate demand growth, so long as oil prices remain elevated (>$70/bbl).
- Infrastructure is already in place/being built to handle the natural gas volumes out of the Permian.
- Dry gas producers continue to grow volumes despite depressed prices and clear abundance of supply.
- At a minimum, dry gas producers should re-establish meaningful free cash flow by materially idling rigs and deferring completions, pursue liquid-rich M&A, and set reasonable "best practice methods."
- The consolidation wave is on in our industry. We urge the gas producers to consider merging with more liquid-rich producers and to pursue this strategy of capital discipline on a combined basis. **Why don't *we* stay?**
- **Leave** the increased capital spending programs. **Leave** the unsustainable reinvestment rates. **Leave** the one-stream dry gas production. **And stay** with the rest of the industry …

I know it's late and I know you're weary
I know your plans don't include me (still here we are)
Both of us lonely
Both of us lonely

We've got tonight
Who needs tomorrow?
Let's make it last
Let's find a way
Turn out the light
Come take my hand now
We've got tonight, babe
Why don't we stay?

Appendix – Supplemental Data

Metric	Period	AR	CHK	CNX	CRK	EQT	GPOR	RRC	SWN	Median	HH
Net Production Mix											
Gas (%)		66.7%	94.9%	91.2%	99.9%	95.4%	90.9%	68.9%	86.2%	91.0%	
NGL (%)		31.1%	1.6%	8.7%	-	4.1%	6.8%	29.2%	11.8%	7.8%	
Oil (%)		2.2%	3.4%	0.1%	0.1%	0.5%	2.3%	1.9%	2.0%	2.0%	
Liquids (%)		33.3%	5.1%	8.8%	0.1%	4.6%	9.1%	31.1%	13.8%	9.0%	
Free Cash Flow Conversion											
FCF / EBITDA	2021	52%	66%	42%	31%	40%	50%	31%	31%	41%	$3.89
FCF / EBITDA	2022	62%	46%	54%	31%	55%	31%	61%	26%	50%	$6.45
FCF / EBITDA	2023	(1%)	3%	32%	(61%)	29%	27%	30%	6%	17%	$2.53
FCF / Mcfe ($)	2021	$0.71	$1.26	$0.86	$0.69	$0.50	$0.99	$0.51	$0.44	$0.70	$3.89
FCF / Mcfe ($)	2022	$1.65	$1.42	$1.22	$1.21	$1.00	$0.67	$1.78	$0.49	$1.21	$6.45
FCF / Mcfe ($)	2023	($0.01)	$0.06	$0.54	($1.08)	$0.44	$0.52	$0.47	$0.09	$0.26	$2.53
FCF / Mcfe ($)	3-Year	$0.77	$0.90	$0.88	$0.25	$0.65	$0.72	$0.92	$0.33	$0.75	
Reinvestment Rate											
Capex / EBITDA	2021	44%	35%	39%	62%	45%	41%	30%	62%	43%	$3.89
Capex / EBITDA	2022	30%	41%	44%	56%	40%	59%	22%	67%	42%	$6.45
Capex / EBITDA	2023	101%	73%	70%	154%	67%	62%	49%	89%	71%	$2.53
Shareholder Return											
% of FCF Returned to Shareholders	2021	-	9%	-	-	1%	-	-	-	-	$3.89
% of FCF Returned to Shareholders	2022	45%	110%	80%	6%	32%	104%	32%	15%	-	$6.45
% of FCF Returned to Shareholders	2023	-	1,094%	105%	-	49%	55%	26%	-	-	$2.53
Dividends Paid ($MM)	2021	-	$119	-	-	-	-	-	-	-	$3.89
Dividends Paid ($MM)	2022	-	$1,212	-	$35	$204	-	$39	-	$17	$6.45
Dividends Paid ($MM)	2023	-	$487	-	$139	$228	-	$77	-	$39	$2.53
Stock Buybacks ($MM)	2021	-	-	-	-	$13	-	-	-	-	$3.89
Stock Buybacks ($MM)	2022	$874	$1,073	$568	-	$409	$250	$400	$125	$405	$6.45
Stock Buybacks ($MM)	2023	$75	$355	$320	-	$201	$109	$19	-	$92	$2.53
Dividend + Stock Appreciation	2022	77.1%	49.4%	22.5%	71.0%	57.6%	2.2%	41.2%	25.5%	45.3%	$6.45
Dividend + Stock Appreciation	2023	(26.8%)	(16.1%)	18.8%	(31.8%)	16.1%	80.9%	22.9%	12.0%	14.0%	$2.53
Dividend + Stock Appreciation	3-Year	316.1%	83.0%	85.2%	116.8%	213.3%	82.6%	361.5%	119.8%	118.3%	
F&D Analysis											
F&D / Mcfe ($)	3-Year	$0.59	$1.14	$1.98	$1.65	$0.89	$0.48	$0.72	$0.87	$0.88	
FCF / F&D (3-Year) Ratio	3-Year	1.3x	0.8x	0.4x	0.2x	0.7x	1.5x	1.3x	0.4x	0.8x	
Net Leverage											
Net Debt / LTM EBITDA	2023	1.4x	0.3x	2.3x	2.9x	1.9x	0.9x	1.3x	1.6x	1.5x	
2024 Outlook											
Total Rigs at YE 2023		3.0	9.0	2.0	7.0	3.5	NA	2.0	NA	3.3	
Change in Rig Count		(1.0)	(2.0)	NA	(2.0)	(1.0)	NA	-	NA	(1.0)	
1-Day Stock Reaction		10.9%	8.0%	1.7%	(1.0%)	(3.3%)	0.3%	(3.3%)	(1.6%)	(0.3%)	

Source: Company 10-Ks and Disclosures, Factset

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