Ohio River Valley Institute

FILLING THE HOLE
PART I: THE PROBLEM

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The Ohio River Valley Institute is an independent, nonprofit research and communications center founded in 2020. We equip the region's residents and decision-makers with the policy research and practical tools they need to advance long-term solutions to some of Appalachia's most significant challenges. Our work includes in-depth research, commentary, and analysis, delivered online, by email, and in-person to policy champions, emerging leaders, and a range of community partners.

EXECUTIVE SUMMARY

This first of a two-part study examines the massive, unfunded liability of decommissioning old wells in Pennsylvania, Ohio, and West Virginia.

Hundreds of thousands of wells have been drilled over more than a century and a half. They are old, produce very little, and contribute very little to the aggregate production of the region. Among the companies that own these wells, non-compliance with decommissioning laws is reportedly an "acceptable norm."

Over 19,000 horizontal shale wells have been drilled in the three states. Some older wells are already being shut-in, and a few companies are being cited for failure to decommission. More importantly, history suggests that the shut-ins (and thus perhaps violations) are likely to continue to grow significantly in the next few years. Meanwhile, drilling longer horizontal laterals means that fewer shale wells are likely to be drilled in the future than have been drilled to date.

Without transformational reform, it is highly likely that the responsibility for decommissioning the region's gas industry will fall to state (and perhaps federal) taxpayers: $31.8 billion dollar liability for 265,000 non-shale wells, at least $7.3 billion for current and high-confidence shale wells (up to $14.6 billion), and potentially billions more for hundreds of thousands of legacy wells that may be found to be leaking. Existing financial assurance available from oil and gas companies to ensure decommissioning totals only $115 million, 0.3% of the liability. What is more, this liability will continue to grow as long as policy remains the same.

Key Findings

- Records and reports of the states' regulatory agencies show that least 500,000 and perhaps more than 1 million unplugged or legacy wells exist in Appalachia: 265,000 unplugged non-shale wells across the three states, plus 345,000 to 892,000 legacy wells that may leak and require repair in the future, the large majority of which were not plugged to modern standards.
- Additionally, over 19,000 horizontal shale wells have been drilled. Regarding future drilling, we estimate that there are between 7,000 and 16,000 economically viable drilling locations.
- Operators rarely plug their wells. If the recent regional pace of plugging were to persist, it would take 299 years to complete the work on these non-shale wells.
- Though unplugged non-shale wells outnumber shale wells by 14 to 1, shale reserves exceed non-shale reserves at a ratio of 24 to 1. That is, 7% of the population of all unplugged wells accounts for 96% of producing reserves.
- The EIA analysis expects no reserve additions from drilling non-shale wells. So, when including undrilled reserves, shale accounts for 98% of the reported reserve volumes in the three states.
- Among unplugged non-shale wells, 99.8% qualify as low-producing stripper wells (less than 90 Mcf per day) and thus earn tax breaks for their low production. Further, 97.9% of the wells produce less than 20 Mcf/d and earn revenues of only a few hundred dollars each month. Mechanically, they average more than 40 years old.
- Decommissioning wells costs $120,000 per well on average, according to the state agencies that plug wells already left to the care of the state.
- The liability for decommissioning unplugged non-shale wells totals about $31.8 billion, plus what plugging may become necessary for legacy wells breached in the future.
- Extrapolating figures reported by public companies, the estimated cost to decommission today's shale wells is between $5 and $8 billion. Decommissioning future shale wells will likely range in cost from $800 million to $6.6 billion at today's costs.
- These estimated costs for shale and non-shale wells are likely low when considering inflation, mechanical deterioration, and increased standards, even when balanced against potential savings from innovation, salvage values, and operating efficiencies.

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INTRODUCTION

The contrast between the old oil and gas industry and the new oil and gas industry stands as stark in the tri-state area as anywhere in North America, and the challenges are as acute. Pennsylvania, Ohio, and West Virginia face hundreds of thousands of old, impoverished wells in need of decommissioning at the same time that they host a small contingent of young, highly profitable shale wells. Plus, they also house hundreds of thousands of unidentified wells abandoned before the modern era of record-keeping and plugging standards. These three populations of wells present distinct—and competing—issues of economics and public health and safety. As the public issues created by unplugged old wells become more apparent, governance needs to find a new way to rebalance the competing interests.

Pennsylvania gave birth to the commercial petroleum industry in the mid-19th century, and by the late 19th century the global epicenter of oil production had shifted to Ohio. Production oscillated and declined for decades, and generations of wells were left behind without modern plugging to obstruct flow and without central records of their location. Only a few years ago before the explosive growth of the shale revolution, Pennsylvania, Ohio, and West Virginia had become sleepy backwaters of the oil and gas industry, with wells producing at extremely low rates. But the states returned to national prominence with the shale revolution, this time dominating natural gas production. The contrasts between the groups of wells are brighter in Appalachia, but most oil-producing states have the same three populations in various proportions.

In the middle of last century, at about the same time when regulatory agencies recognized the need to plug old wellbores to prevent unwanted flows of formation fluids to the surface and aquifers, the agencies also recognized the need for financial assurance in advance to make sure that the required work would be completed. After all, there is, by definition, no more profit to be had from a well that is ready to be plugged. The conventional tool of financial assurance has been a surety bond posted by the oil company to cover a portion of the costs, but the system of bonding did not evolve as the industry did, and it no longer serves its intended purpose.

The required bonds probably never sufficed to cover all the obligations even for small companies, and the bonds were proportionally smaller for larger companies. Evidently, regulators believed that large companies presented small risks, presuming continuous growth and reinvestment of a non-renewable resource. In the same period, regulators attempted to keep the liability to a minimum by requiring prompt plugging of wells after they stopped producing. Oil companies kept a short list of liabilities by paying the decommissioning costs of individual wells as they came due.

But financial assurance did not adapt as reality and regulations evolved. The value of required bonds increased too little, sometimes going 40 or even 70 years without increase. Thus, they did not escalate with the cost of oilfield services or with the scope of decommissioning operations expected. After the price collapse of 1986, regulators across the country allowed oil companies to warehouse idle wells instead of plugging them promptly, causing an inventory of liabilities to accumulate. The non-renewable resources have matured into a new phase of their lifecycle, and most companies focus now on depleting old wells instead of drilling new ones. Experience has shown that the threat of failure by large companies is, indeed, large.

Parallel dynamics played out nationwide and left many jurisdictions in similar positions. A number of these jurisdictions have attempted in recent years to reform their systems of financial assurance so that industry will pay its end-of-life obligations. Mostly they attempted to dial up the parameters of the same conventional policy tools. Reforms faced stiff opposition and ended in compromises. Research has shown that most states now possess financial assurance sufficient to cover only a few percent of the obligations,[1] and other research has shown that large segments of unplugged wells are no longer capable of funding their own decommissioning even if all future profits were directed to the task instead of to owners.[2]

Policymakers now face three basic options: change policies to require industry to fund its clean-up, allow the clean-up to fall on taxpayers, or plan not to do the clean-up. The possibilities of repurposing wells or paying for plugging with charitable donations remain remote and, at best, partial solutions. Meanwhile, the need for clean-up was canonized decades ago, and evidence of the risk of old wells continues to grow.

Regulations have become so outdated that any effective change will be painful; there is no easy answer. But the options reduce to a zero-sum problem: either the oil and gas industry funds its clean-up at the end of life, or the public will pay some combination of economic and environmental costs.

In practice, landowners and governments have trusted oil and gas companies to meet the obligations owed them even while companies' assets depleted over decades, but the resurgence of new production creates an opportunity to remedy delinquent planning. Solving the problem creates cleaner air, better water, plus sustained employment and economic activity without taxes on the general public.

PAST AND FUTURE WELLS IN APPALACHIA

In order to protect natural resources, public health, and ongoing urban development from the risk of leaks from old wellbores,[3] the three main oil and gas producing states of Appalachia face the challenge of securely and permanently decommissioning the birthplace of the global oil and gas industry after more than 150 years of history. Designing an effective policy requires a crisp understanding of the state of the industry as it now stands and where it is headed.

Despite the many wells drilled over the decades, the varieties of situations can be simplified into three substantially different groups of wells, two with subdivisions:

- **legacy wells:** historical "abandoned"[4] wells from about the first 100 years of the oil and gas industry—often undocumented and often poorly plugged—plus wells documented and plugged in modern times,
- **unplugged non-shale wells:** mostly vertical wells to conventional reservoirs now producing little or nothing,
- **horizontal shale wells, existing and future:** modern wells drilled (or to be drilled in the future) horizontally to shale plays such as the Marcellus, Utica, and Point Pleasant formations. Few of these wells have been plugged, and operators continue to drill new wells.

Legacy wells

Legacy wells are those that have already reached the end of their lives and been resolved according to contemporaneous standards, though at some times that may have meant simply walking away. They subdivide into two parts: wells decommissioned to modern standards and those to pre-modern standards. Table 1 below characterizes legacy wells, a combination of figures taken from reports by the regulatory agencies to the Interstate Oil and Gas Commission about unidentified wells and our own analysis of state records for plugged wells.

Table 1: Legacy well counts for the three states.

	Legacy Wells			
Status	Pennsylvania	West Virginia	Ohio	**Total**
Unidentified wells	100,000 to 560,000	9,000 to 66,000	35,000 to 65,000	**144,000 to 691,000**
Plugged wells	71,000	25,000	105,000	**201,000**
Legacy wells	171,000 to 631,000	34,000 to 91,000	140,000 to 170,000	**345,000 to 892,000**

Commercial oil well drilling began in Pennsylvania in 1859, but gas wells had been drilled in the region for decades. On the other hand, the uniform system of well identification known as "API numbers" and "Unique Well Identifiers" was not implemented until 1967. Modern methods of plugging were not adopted in most states until about the same time. So, the oil and gas industry operated in the tri-state area for a century with weak record-keeping and pre-modern methods for closing a well.

Despite limited records, it is clear that the states house large populations of unidentified or "undocumented"[5] wells, up to 560,000 in Pennsylvania alone. The figures in the tables were reported by the state agencies to the Interstate Oil and Gas Compact Commission (IOGCC) and published last year, each setting their own methods for estimation. Independent research has examined the number of unidentified wells in Pennsylvania[6] and arrived at similar values, though it is less current.

The number of legacy wells reported by the regulator in West Virginia is proportionally lower than the more-researched estimates in Pennsylvania. Researchers in West Virginia subtotal well types a little differently, but they place the low end of the number of unidentified wells at 63,000, about the same as the high end reported here.[7] They figure that the best estimate is 440,000 unidentified wells and that the figure could be as high as 760,000.

We have not found independent research to corroborate the well counts in Ohio, but the figures appear markedly lower than estimates in the other two states. Our attempts to reproduce the Ohio figures corroborate that they may be more conservative estimates than the other two states. Though the totals may be low, these best estimates show that the pool of potential problem wells is quite large, potentially several times as large as the population of wells plugged to modern standards.

The table shows separately wells documented to have been decommissioned. In most jurisdictions, documentation of wells began about the same time as improved plugging standards, so we consider these to present less risk of future leaks.

A body of research has demonstrated that legacy wells in the region can and do leak methane and cause other environmental issues. When legacy wells are found to be leaking, the last operator nominally becomes responsible. Commonly, however, the previous operator no longer exists, so historical leaking wells become the responsibility of public programs.

The inventory of legacy wells represents a pool of potential liability that could fall to taxpayers in the future, and that liability is likely to grow. Efforts seem to be expanding to identify old wells and to measure their emissions, adding to the inventory of work at public expense. Plugged wells secured today still risk deterioration and breaches in the future. And the kinds of companies that owned these low-producing, non-shale wells are not the kinds of companies continuing to reinvest in growth, meaning they are less likely to be available to resolve problems as they are discovered.

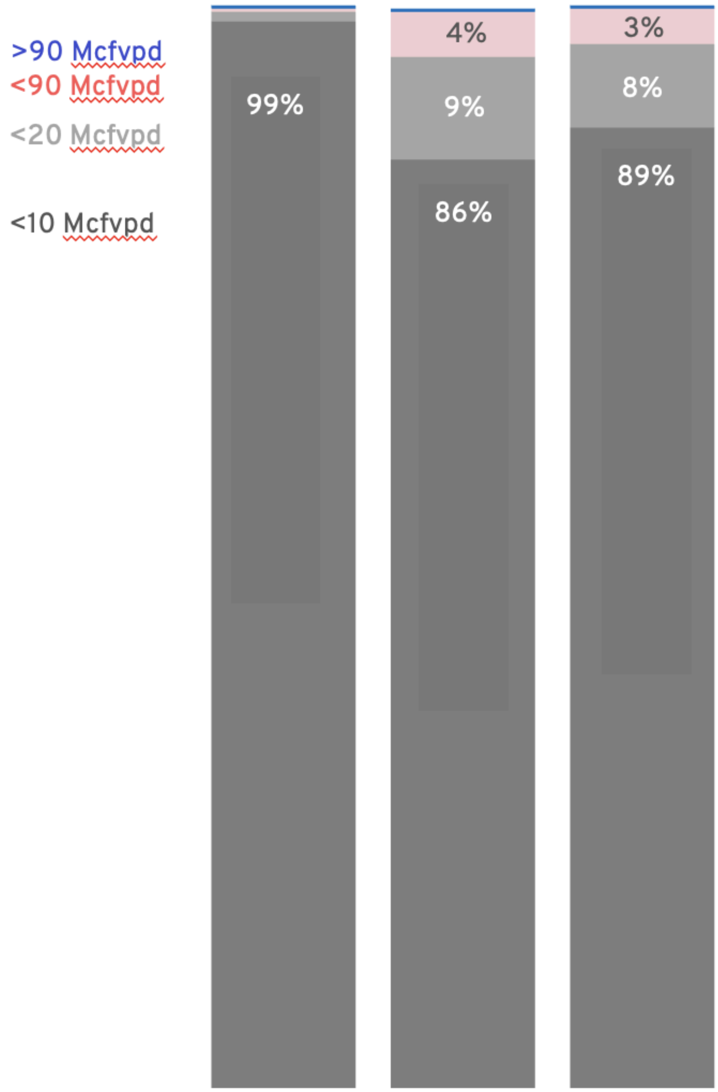
Unplugged non-shale wells

The most immediate decommissioning need in the states pertains to the hundreds of thousands of decades-old wells drilled prior to the shale revolution that now produce little or nothing.

We call this category "non-shale wells" because it does include some variety. Most of the wells are vertical, though some were drilled horizontally. Most target higher-permeability conventional reservoirs, though some target coalbed methane or naturally fractured shale formations which were historically called "unconventional." A few vertical wells made early tests of the shale plays, and some other vertical wells have been drilled to non-shale formations since the start of the shale revolution. For this analysis work, "shale wells" means horizontal wells drilled since 2005, and "non-shale wells" include all others.

Figure 1 below helps to characterize the population of non-shale wells. Each column of the graph pertains to a single state. The colored segments represent the portion of wells within rates of recent production rate,[8] and the table below the figure reports key statistics.

Figure 1: Distributions of age and recent production from unplugged non-shale wells in each state. As noted above, 1 barrel of oil translates to 20 thousand cubic feet of equivalent value (Mcfv).



Non-shale wells	PA	WV	OH
Count	134,000	70,000	61,000
Avg rate	1.8 Mcfvpd	5.6	4.6
Avg age	32 years	47	49

These wells generate little income. Wells producing less than 90 Mcfv qualify for tax breaks based on their status as "stripper" wells, and 99.8% of unplugged non-shale wells in the three states meet this criterion.[9] Worse, 97.9% produce less than 20 Mcfvpd, and 93.1% produce less than 10 Mcfvpd.

Given local wellhead prices and royalty burdens, wells making 10 or 20 Mcfvpd likely generate only a couple of hundred dollars of revenue each month with which to pay operating costs. Previous analysis has shown how wells are operated in the region below the level of profitability.[10] Even if the wells can be operated for less than a few hundred dollars per month to make a small profit, it is highly unlikely that wells in this large category will make enough production in the future to fund their own decommissioning (as discussed below), even if all future proceeds were dedicated to the task instead of distributed to owners.

Perhaps due to the tight financial circumstances, the pace of regulatory violations is high while the pace of voluntary decommissioning by oil companies is extremely slow. A report by Pennsylvania's Department of Environmental Protection (DEP) found that violations of environmental rules by conventional gas companies were so systemic that a "culture of non-compliance [is] an acceptable norm in the conventional oil and gas industry."[11] The report found that the most frequent and "most disturbing" failure was the failure to comply with plugging requirements. And the pattern has continued expanding. In 2023, the DEP issued 6,860 total notices of violations, 26% more than it had in 2022, 52% more than it had in 2021, and nearly six times as many as it had in 2015.[12] Specifically, 512 citations were issued for failure to plug wells in 2023 and 671 violations were cited in 2022. The pace of violations in early 2024 suggests another new record of violations.[13]

Compared to the number of unplugged wells, very few wells are being plugged each year. Table 2 below shows the number of unplugged non-shale wells in each state and the average number of wells plugged annually from 2018 to 2023 by private companies.[14] The last row shows how long it would take to plug the existing non-shale wells at the current rate, separate from the plugging of shale wells, from 269 years in Pennsylvania to 373 years in West Virginia.

Table 2: Unplugged non-shale wells and average wells plugged by private companies each year.

Unplugged Non-Shale Wells and Plugging

	Pennsylvania	West Virginia	Ohio	**Total**
Unplugged non-shale wells	134,000	70,000	61,000	**265,000**
Private wells plugged (average 2018 to 2023)	499	188	200	**887**
Years at current pace	269	373	305	**299**

Taken together, these show that current owners are unlikely to fund a significant portion of the clean-up obligations before bankrupting hundreds of thousands of wells to the public treasury.

Shale wells, existing and future

The last category of wells in the region sits mostly at the opposite end of the spectrum. The large majority of production and the large majority of drilling come from a small number of wells to the shale plays of the region. In fact, these plays have come to figure prominently in the national supply of gas, displacing supply from other regions by their high production and high profitability. The resource base remains large, and drilling and production are likely to continue for many years. In the end, tens of thousands of wells will need to be securely plugged, and they present unique challenges as described below.

Figure 2 below compares the statewide production from the two main categories, non-shale wells in orange and shale wells in purple. The figure reinforces the discrepancy between the low production from the larger group of non-shale wells and the large production from the relatively few horizontal shale wells.

The figure is clear but more quantitative information about the discrepancy exists. Each year the U.S. Energy Information Administration (EIA) compiles reserve information from oil companies across the country, including volumes forecasted as "reasonably certain" to be recovered from existing or planning wells under current conditions. In most regions, the self-reported expectations of operators about future production and drilling cover the substantial majority of the region, and the results of the most recent study[15] are shown in Table 3 below.

Figure 2: Gas-equivalent production (by value) of recent horizontal and other wells by state.

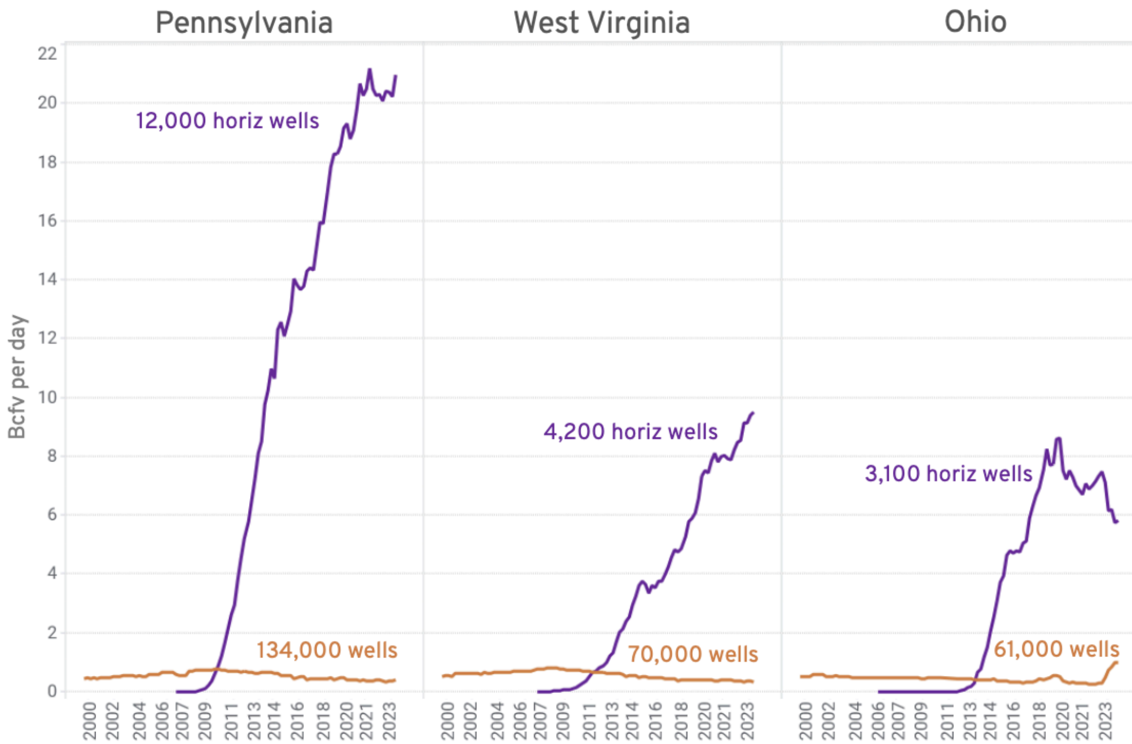


Table 3: Reserves by state reported by EIA as of year-end 2022

		Pennsylvania		West Virginia		Ohio		Total	
Status		Gas	Oil	Gas	Oil	Gas	Oil	**Gas (Bcf)**	Oil (MMStb)
Producing	Shale	70,191		28,184		16,248		114,623	
	Non-shale	1,313		2,706		464		4,483	
	Total	**71,504**		**30,890**		**16,712**		**119,106**	
Non-producing	Shale	34,807		20,042		16,114		70,963	
	Non-shale	0		0		0		0	
	Total	**34,807**		**20,042**		**16,114**		**70,963**	
Total	Shale	104,998	31	48,226	90	32,362	227	185,586	348
	Non-shale	1,313	1	2,706	0	463	0	4,482	1
	Total	**106,311**	32	**50,932**	90	**32,825**	227	**190,068**	349

The figures show that oil constitutes a trivial fraction of reserves in the region, and it shows that gas company respondents expected zero drilling (*i.e.* non-producing reserves) outside of the shale plays. More to the point, despite constituting 93% of all wells in the region, non-shale wells contribute less than 4% producing reserves. Adding consideration for firm drilling plans (*i.e.* non-producing reserves) in shale, non-shale production constitutes only 2% of reserves in the tri-state area.

Figure 3: Map of unplugged wells.

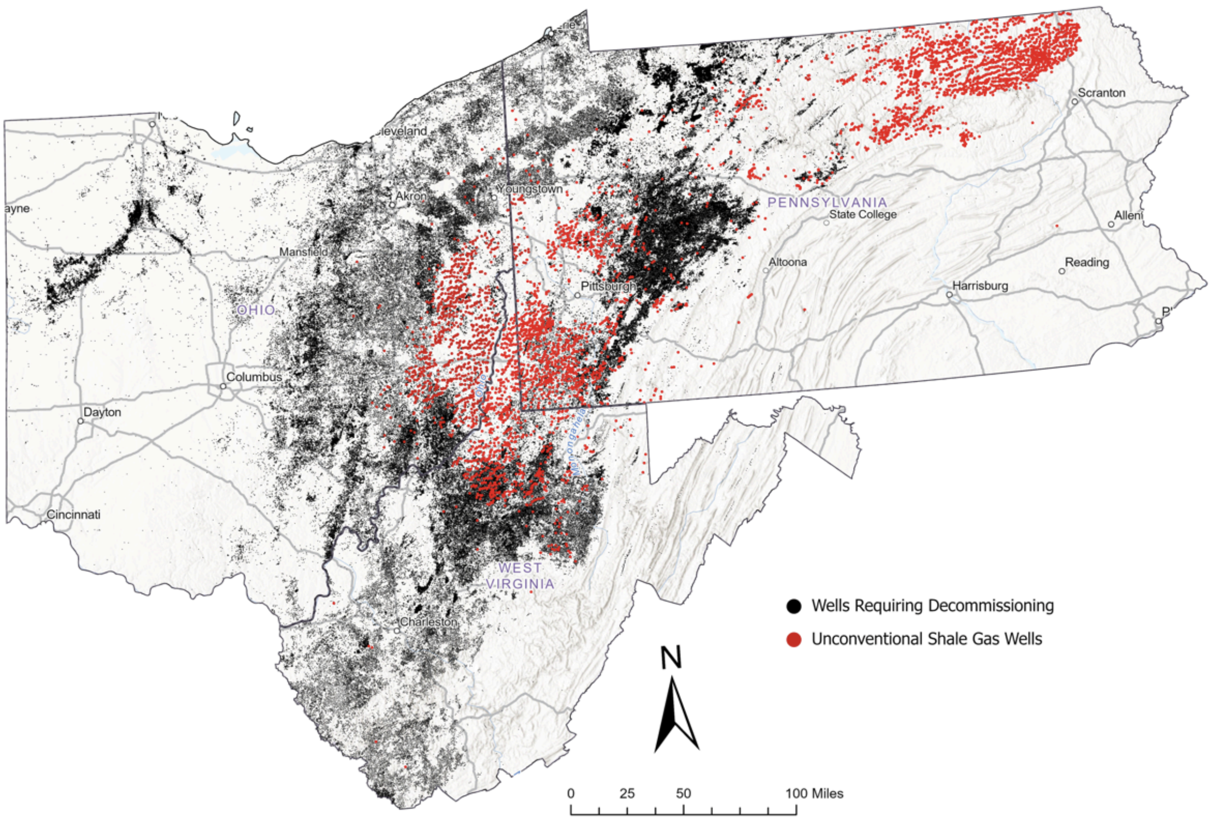
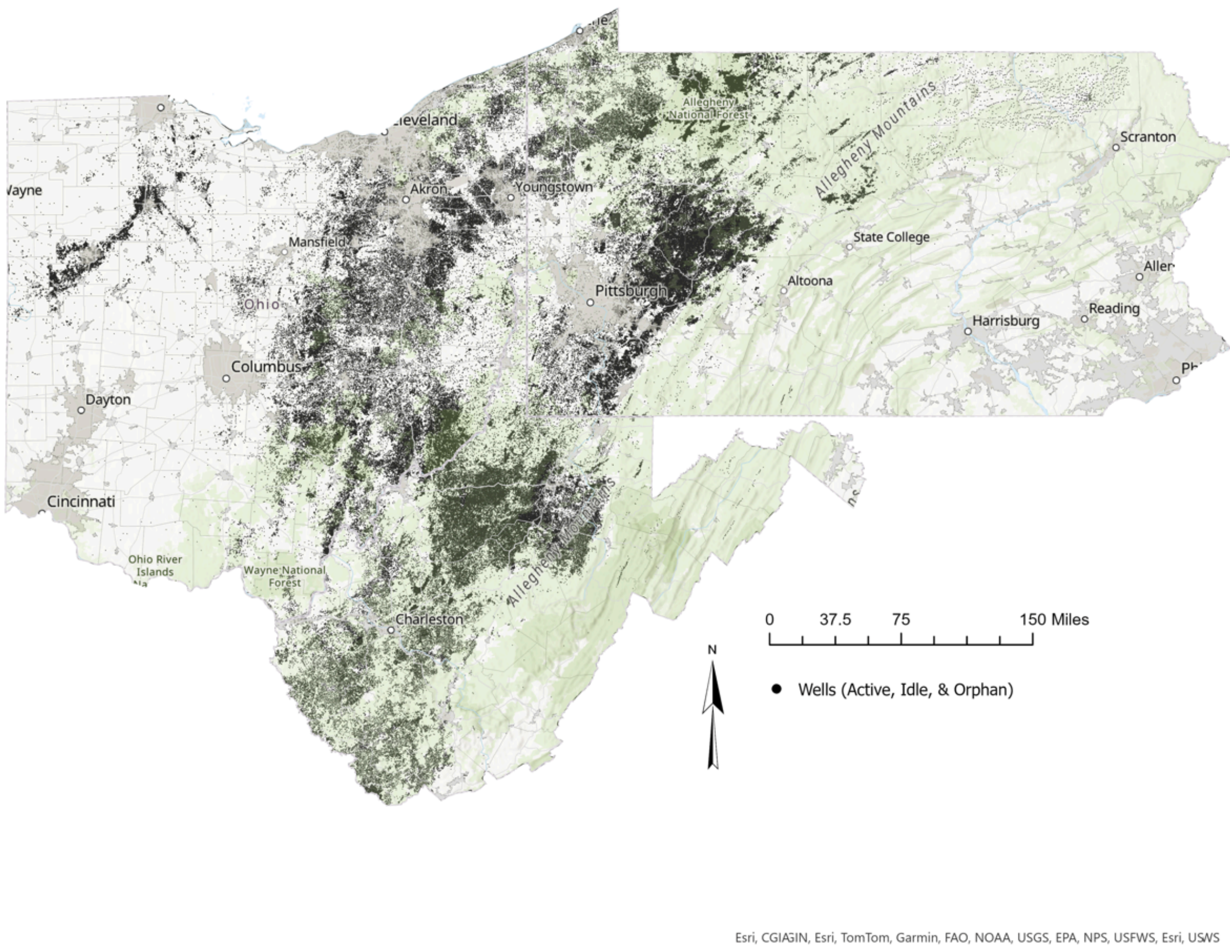


Figure 3 provides a visual reference for the location of unplugged wells, both shale and non-shale, and Figure 4 overlays urban areas and land cover to illustrate the overlap with people and resources in need of protection from emissions. The much larger population of unplugged non-shale wells also occupy a much larger area, including urban areas from Cleveland to Pittsburgh to Charleston and to the east side of Columbus, while contributing little production.

Figure 4: Map of unplugged well locations, urban areas, and land cover.

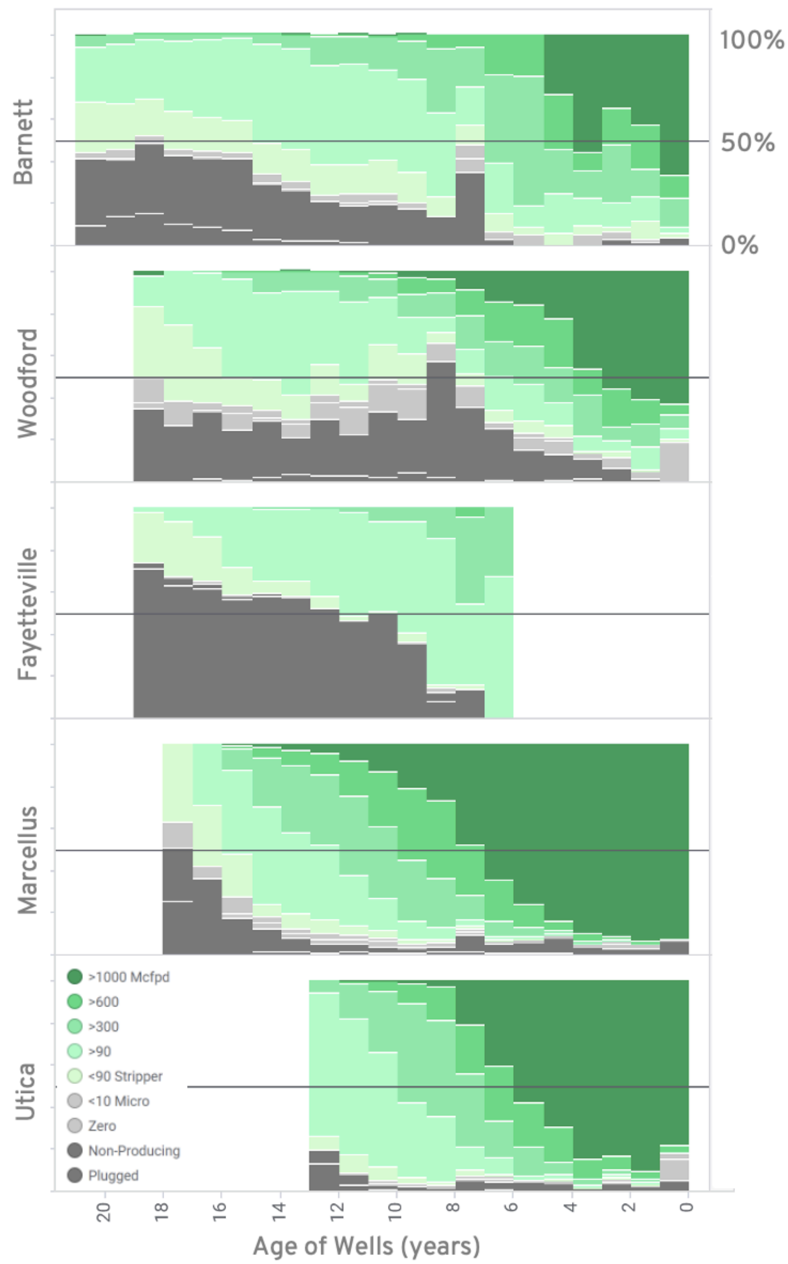


Depletion of existing wells

For the sake of preparation and planning to plug these shale wells when they retire in the near future, it is necessary to understand both the dynamics of those particular plays and the decommissioning costs they will impose.

Three significant shale gas plays—the Barnett Shale in Texas, the Fayetteville Shale in Arkansas, and the Woodford Shale across a couple of basins in Oklahoma—launched before the Marcellus play in Appalachia, and all of those predate the Utica formation. Figure 5 characterizes the empirical longevity of each year's cohort of wells in the five plays, each in a separate panel. Without the projection of future dynamics, these three early plays provide empirical analogies for the lifecycles of shale gas wells in the younger Appalachian plays.

Figure 5: Current production rates by year of wells in major shale gas plays.



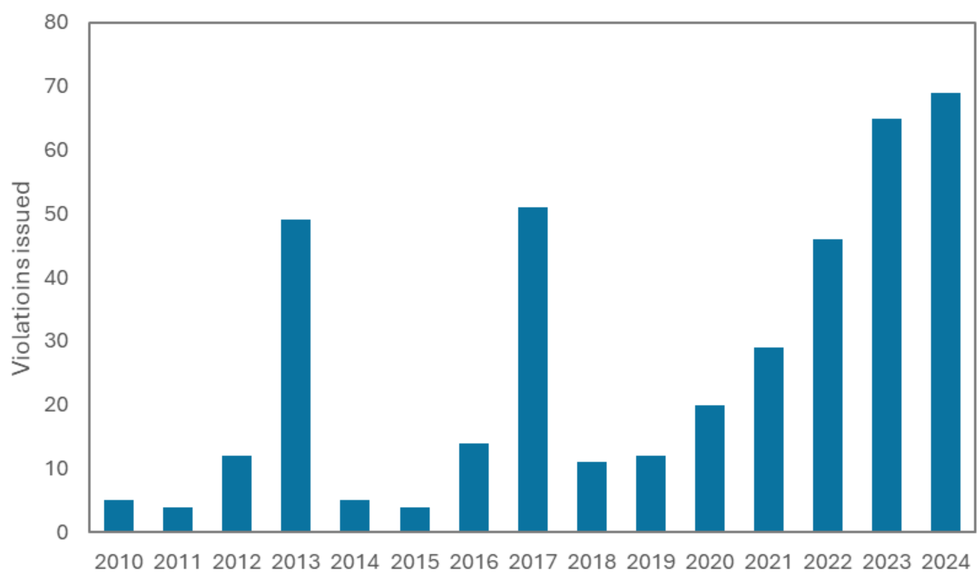
While regional production holds a high plateau, individual wells deplete and can reach the end of their economic life, and the figure shows how the distribution of producing rates declines with time. Each column represents the population of wells that began production in each prior year, with the most recent wells at the far right and the older wells to the left. The bars are normalized to 100% so that each segment shows the proportion of wells in each cohort of each play currently producing at rates within each colored bin. Dark gray marks the proportion of wells sitting plugged or idle, and the light gray marks wells purportedly active but showing “micro” production of up to 10 Mcfpd. These are wells contributing little or nothing to cash flow—almost pure liability. The greens represent active producing wells from stripper wells (<90 Mcfpd) in the lightest green to dark green for wells over 1 million cubic feet per day (MMcfpd).

The chart demonstrates with historical production that older shale gas wells have demonstrated relatively short productive lives, a fraction of the decades sometimes discussed. During the development of the Barnett Shale, it was widely expected that the wells would ultimately decline at only 6% per year and produce for 50 years or more. Today 45% of wells more than 15 years old are plugged or stand idle.[16] Wells in the Woodford Shale were forecast to endure more than 30 years, but about 40% of wells ended production by year eight. Marcellus and Utica wells have produced at higher rates and maintained longer lives. Still, the layered transition from darker greens to lighter is clearly visible in the plays, and both suggest the start of the same kind of late-life shut-ins demonstrated by the analogs.

A recent peer-reviewed article in the geologic literature offered a less sanguine outlook.[17] Based on extrapolations of historical shut-ins based on assumed statistical forms tuned to actual results, researchers found that the maximum survival of Marcellus wells ranged in various areas from 13.8 to 15.7 years. It appears that a slightly different tuning to match historical shut-ins could extend the implied life to comport with our analysis.

Data shows that shale companies have already begun to defer plugging in the same way that conventional companies have. Figure 6 below graphs the number of citations issued each year by Pennsylvania's Department of Environmental Protection[18] for failure to plug shale wells steadily and significantly increasing over the last six years. A total of 396 violations have been issued relating to 171 wells. Even after repeated citations, only 47 have returned to production, and only 66 have been plugged. Last year showed the highest number of citations, the highest number of unique wells, and the highest number of shale companies cited (12). [19]

Figure 6: Violations of plugging requirements of shale wells in Pennsylvania.



Whether by qualitative or quantitative analogy, the evidence shows that horizontal shale wells will join the warehouse of accumulated liability within the coming years while the current inventory of conventional wells is being plugged at a glacial pace.

"100-year supply of natural gas"

Meanwhile, new wells will continue to be drilled and will continue to add to eventual liability. Policies and practices to plan for that eventual liability should be clear about the future of drilling, as best as we can foresee it.

Since President Obama trumpeted the point in his 2012 reelection campaign, many have quoted and believed that the United States as a whole (and Appalachia by extension) possesses enough natural gas to continue current production for 100 years. In recent years, the American Petroleum Institute (API), the American Gas Association (AGA), and the National Petroleum Council have continued to cite the 100-year supply figure.[20] It is, indeed, still possible to divide two numbers and calculate an implication of many years of supply. But neither of the two inputs to the figure is what one might assume, and the result is now no better than it was before the shale revolution. For both reasons, the unreliable estimate of 100 years of supply sets unrealistic expectations for the future drilling of new wells.

The Energy Information Agency makes an extrapolation to "technically recoverable resources" for its Annual Energy Outlook using surveys of producing companies, its own analyses, and analyses of sibling organizations like the United States Geological Survey. When President Obama initially claimed over 100 years of supply in 2012, the EIA figures showed 101.8 years of technically recoverable resources. In the last year before shale gas became a major contributor to the estimate, the figure had been 73.9 years. [21,22]

Since then, however, the outlook has continued to change. Drilling and evaluation have continued, but we have also produced a great deal of gas and approximately doubled our pace of demand. In total, the years of supply have been diminishing, and the most recent extrapolation by EIA shows 73.6 years. The U.S. has now returned to the same position it was in before the shale revolution except that there are no prospects for another game-changing class of supply.

Although the most analogous and most widely relied upon figure has now returned to pre-shale levels, industry organizations continue to cite the 100-year figure. We do find a way to calculate such a number, but it requires a different source and a tortured interpretation. The API and the AGA sponsor a biennial survey and publish the results under the name of the Potential Gas Committee,[23] and its most recent report arrives at a higher figure.[24] In order to recognize "more than 100 years of supply," the industry organizations must use this relatively obscure source, include volumes that cannot be produced at today's prices, add volumes not yet found to exist at all,[25] use a high-side estimate of both kinds of volumes,[26] *and* evidently ignore current and growing production slated for export. The figure of 100 years sounds compelling, but it is not a useful number.

EIA's figure of 74 years of "technically recoverable resources" (TRR) remains of marginal value for planning because it also excludes the criteria of economic viability, excludes planned export growth, and includes a great deal of uncertainty. EIA explains:

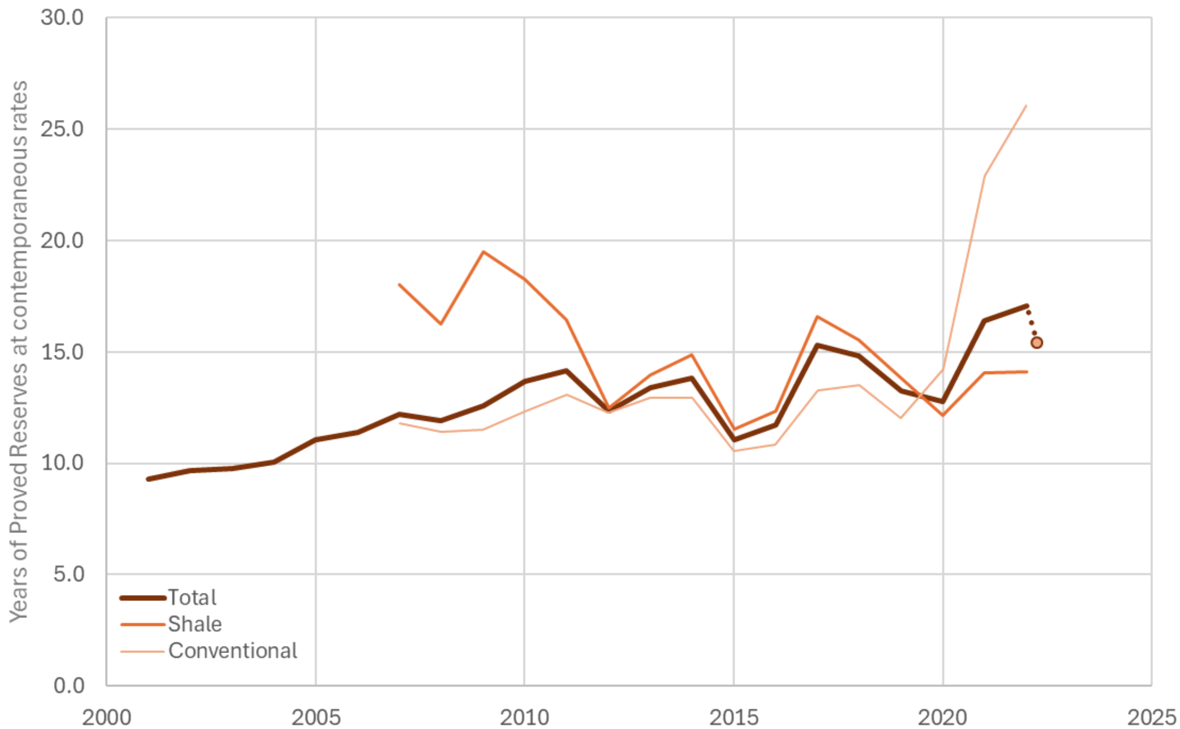
> *"Estimates of TRR are highly uncertain, particularly in emerging plays where relatively few wells have been drilled. Early estimates tend to vary and shift significantly over time. . ."*

More quantitatively, the report goes on to assume variations in which the TRR could be 50% lower or higher.[27] The volume is only crudely estimated and allows for the price paid by consumers to increase by multiples. It represents a kind of theoretical target volume that might be realized in the future subject to on-going engineering, geologic, technological, and economic inputs.

As with publicly traded oil companies, the most relevant measure of future production is called "proved reserves"—volumes known to exist, believed to be economically viable at current prices, and estimated with a high degree of confidence. And the most relevant measure of the pace of depletion is total production including current and planned exports. Estimates of proved reserves have increased dramatically since the start of the shale revolution, but so has production. A more useful measure of years of supply has certainly increased but it still remains closer to 15 years than "over 100 years."

As mentioned above, the EIA has surveyed oil and gas companies and tallied and extended the results each year to create a national estimate of high-confidence proved reserves, both drilled and remaining to be drilled, including a reconciliation to prior year estimates.[28] Figure 7 below shows the ratio of proved reserves to contemporaneous production from before the start of the shale revolution in 2005 to year-end 2022. The bold line represents the national total while the thinner and lighter lines represent shale and conventional reserves separately. The dashed line and marker represent the revision to 2022 reserves as published by the EIA this spring.[29]

Figure 7: Proved producing and non-producing reserves in the U.S. divided by contemporaneous production.



Overall, the supply has increased from about 10 years to about 15 years, still a significant gain on a proportion basis.

More interestingly, the proved years of supply of shale gas has remained relatively flat since 2012 while mostly *decreasing* since 2017. Before this spring's downward revision, proved gas reserves from shale totaled only 14 years at contemporaneous rates. The national average would be below 14 years—and hardly different from the remaining life of the aging conventional production—except for the conversion of known but previously nonviable gas volumes on the north slope of Alaska which have not yet begun production.

Using the same measure for the Appalachian states, the EIA analysis shows 14.1 years of proved reserves for Pennsylvania, 14.7 for Ohio, and 16.8 for West Virginia. Nearly two-thirds of those reserves (63%) have already been drilled, suggesting that without an increase in price the majority of the viable locations in three states has already been drilled.

What is more, these calculations do not account for the on-going construction of additional export capacity that will accelerate calls on those reserves. The EIA's most recent reference case forecast calls for natural gas to peak in 2032 followed by a slow decline so that its most recent volume of proved reserves[30] will be produced by the end of 2039, 14 years from now.[31]

The EIA does rightly extrapolate that the U.S. will continue to produce gas after 2039. To reach that date and to continue, though, the EIA projects both improving technology and increasing the cost of gas to consumers. Having averaged $2.19 per unit of gas in 2024, the EIA forecasts an average real price of $4.35 from 2030 to 2039 plus continuing increases. Adding consideration of inflation would increase the name plate price; fourteen years of inflation at 2.5% suggests a nominal price over $6.00 in order to maintain that long, slow decline.

Drilling and production of shale gas will continue for many years; how many depends on how technology and prices unfold. Already on today's trajectory, production would peak and decline sooner rather than later without a significant increase in prices.

As an analogy for expectations of future shale gas drilling, it may be useful also to consider the outlook for future drilling of shale oil. The EIA's analysis this spring reports proved reserves equal to 11.1 years of contemporaneous production, yet it called for production to decline after 2027. Recent comments by major oil industry executives appear to bear out the expectation. Occidental Petroleum CEO Vicki Hollub stated publicly in March that she expects U.S. oil production to peak between 2027 and 2030. At the same industry conference, ConocoPhillips CEO Ryan Lance echoed a similar conclusion, namely that U.S. oil will plateau by 2030. [32] The same week former CEO of Pioneer Resources Scott Sheffield responded when asked about the ability to grow U.S. oil production,

> *"One of the main reasons that Pioneer sold. . .we were running out of Tier 1 inventory. Everybody's running out of Tier 1 inventory. Tier 1, the best inventory, is going to be run out of Pioneer by 2028, Tier 2 by (20)32. So, what people don't talk about is the fact that we are running out of inventory."*[33]

The shale gas plays have taken a different path of development. Still, it remains noteworthy that most oil shale basins have already peaked and that the best oil shale basin can foresee the exhaustion of its best inventory. Knowing more now than we ever have, the end of plateau oil production now appears surprisingly soon.

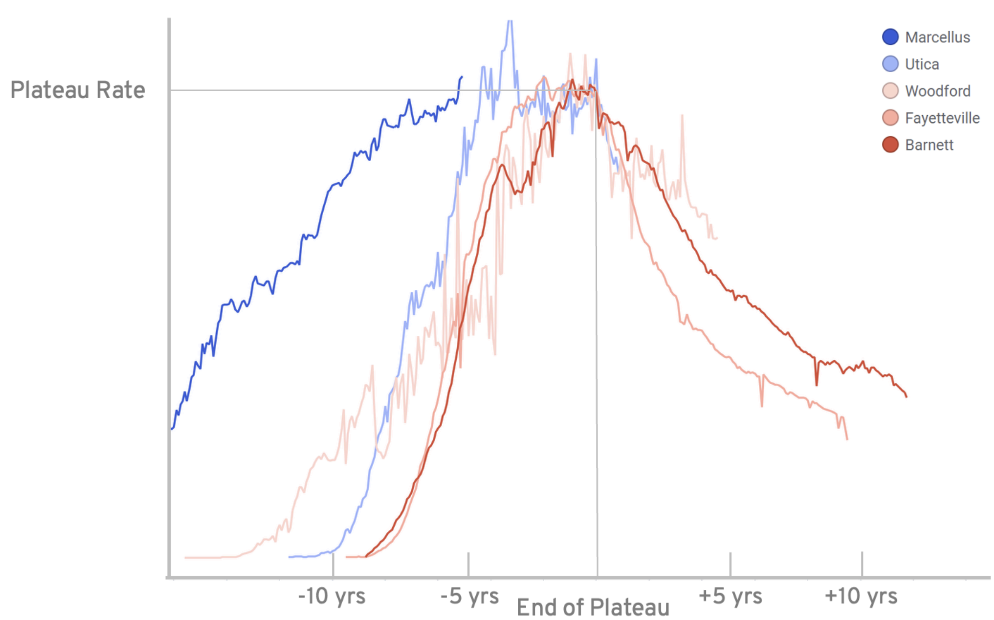
Moreover, the longer Appalachian gas maintains its plateau production, the more old wells would have to be plugged by profits from the declining tail of production.

End plateau production from a play

Of course, basin production will ramp down before it ends—generating less and less money that could be used for decommissioning. The same predecessor shale gas plays that demonstrated how older wells deplete and shut-in also provide an example of how aggregate production can decline when drilling finally ramps down. The Marcellus play has not yet reached the end of its production plateau, which means it will likely have a larger accumulated liability when decline begins. As long as drilling continues and production remains high, companies retain significant future revenues and reinvestment to fund end-of-life liabilities. The EIA forecast calls for sustained high prices for gas, but production can reverse quickly and can be compounded by the often-concomitant drop of commodity price.

Figure 8 shows the total production of gas from wells in five shale gas plays,[34] with older plays in red and Appalachian plays in blue. The well-known fact that shale wells' production declines very rapidly at the start of production means that the headline total of production depends heavily on the pace of completing new wells. Drilling in the three older plays slowed or nearly stopped years ago, so they demonstrate not just the pattern of rapid increases of production as activity gears up but also the rapid decline as the play comes to maturity.

Figure 8: Production from major shale gas plays.



The plays reached different maximum rates on different dates, so the figure normalizes the disparate histories to the approximate end of plateau production. Only the Marcellus has not demonstrated a decline in production, and it is likely to demonstrate a longer plateau than the others.[35] The historical production is normalized to the recent maximum rate but also to an arbitrary date in such a way as to make the trend visible.

The examples of previous plays (including the Utica play that dominates Ohio) demonstrate how rapidly production can fall. Experience says that the onset of decline has also arrived unexpectedly, and the examples show that production has fallen about 35% to 55% in the following five years. The longer the plateau persists, the larger the mass of accumulated liability when revenues do turn down, and the harder it will be to manage funding when the need comes into sight. If policymakers wait until they see the end of plateau production, then the industry risks not having enough remaining profits to meet their obligations. Considering that impactful new policymaking can stretch out many years, the time to start is now.

Wells yet to be drilled

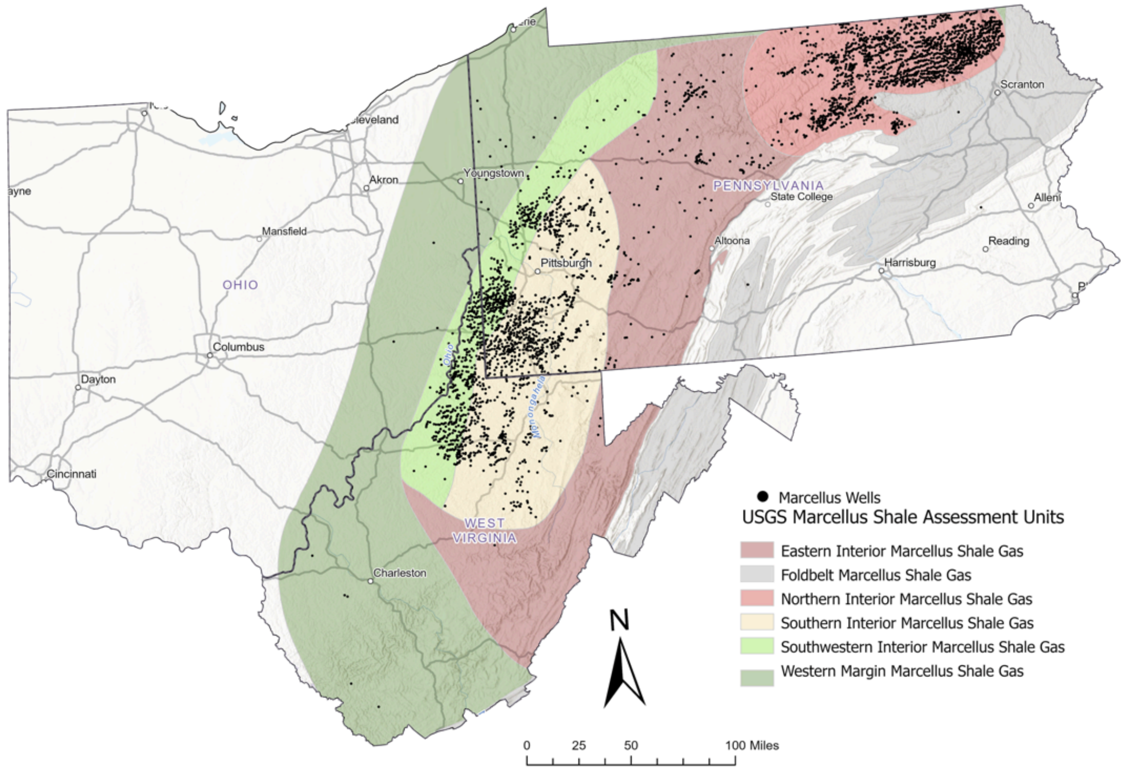
In the meantime, drilling continues, and the ultimate decommissioning liability continues to grow. To estimate the scope of future drilling, we have reviewed literature and made three independent scoping analyses which arrive at consistent implications. We estimate that there are between 7,000 and 16,000 economically viable drilling locations, adding between 35% and 80% to the liability of the roughly 20,000 wells already drilled.

Historical studies of the Marcellus and Utica Shales have focused on the volumes in place and the volumes that are technically possible to produce but which would require an infinite gas price to achieve (technically recoverable resources). The series of analyses show a genuinely gigantic resource, [36] but the relevant question is what can be economically drilled and produced. To arrive at an implied well count, we must divide the resource volumes by estimates of recovery per well and an assumption about well density. Technically, our analysis shows that the plays could accommodate up to roughly 100,000 future locations, including a major unproven extension of the Utica into Pennsylvania. However, as discussed above, the definition of TRR and the history show that economic recovery is much less than technically recoverable, so the figure does not serve a practical purpose for planning.

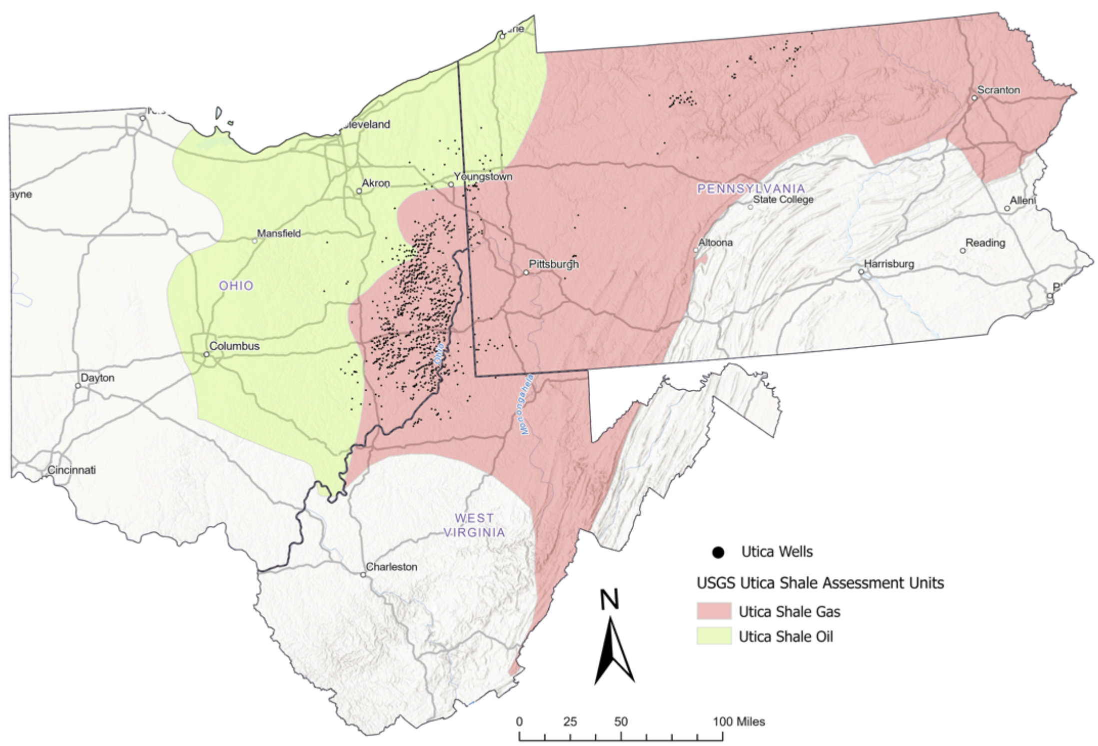
At the other end of the range of estimates is the most recent estimate of proved non-producing reserves from the same EIA reserve report cited above. Because these volumes include high-confidence plans for the future, they represent a reasonable low-side estimate.[37] As with TRR, we must assume a recovery per well to estimate wellcount. Combining per-well recoveries reported in investor presentations covering the separate areas of the plays, proved reserves reported by operators in the region to the EIA translate to only about 3,200 future drilling locations.

Figure 9 below shows the approximate range of these future wells. The colored areas represent areas of large-scale similarity based on a synthesis of literature, and the black dots represent existing wells. The areas with concentrated historical drilling are the areas most likely to be drilled in the near future, but the full area represents the full extent of the formations' theoretical productivity and thus theoretical decommissioning liability.

Figure 9: Regions of large-scale geological similarity and historical drilling of Marcellus and Utica Shales.



data.pa.gov, Esri, TomTom, Garmin, FAO, NOAA, USGS, EPA, NPS, USFWS, Esri, CGIAR, USGS



data.pa.gov, Esri, TomTom, Garmin, FAO, NOAA, USGS, EPA, NPS, USFWS, Esri, CGIAR, USGS

The most likely outcome falls in between these estimates, but probability favors the low side of the range. We find several useful guides for a central estimate of future drilling. A peer-reviewed paper in the oil and gas literature looked directly at economic viability of the Marcellus play at about the same date as the latest EIA reserve report, and it calculated 11,500 remaining economically viable wellbore locations, mostly outside of the core area of the Marcellus where drilling has been concentrated.

We separately took two other analytical tacts on the estimate: estimation of the extent of development of TRR by county given the urban area and rock quality in each, and extrapolation of drilling necessary to maintain a plateau production from the region. Both involve a wide range of uncertainty, but sensible estimates in both comport with the more rigorous published analysis. Table 4 summarizes our synthesis of the group of analyses. In short, we interpret current high-confidence locations to number from about 7,000 to about 16,000 by comparison to the 20,000 already drilled.

Table 4: Estimated ranges of wells likely to be drilled in the Marcellus and Utica Shale plays in the future.

	Estimates of Future Wells			
	Pennsylvania	West Virginia	Ohio	**Total**
Proved Reserves	1,500	1,000	700	**3,200**
Non-proved	1,800 to 6,900	1,200 to 4,000	300 to 1,800	**3,300 to 12,700**
Total	3,300 to 8,400	2,200 to 5,000	1,000 to 2,500	**6,500 to 15,900**

Of course, the full range of possibilities is wider, and the economic, political, and technical contexts will all evolve. For example, the more export facilities are built for liquified natural gas (LNG) above today's export capacity, the more wells will be required. For present planning purposes, these serve to demonstrate that the states need to be prepared to deal with the decommissioning of as-yet undrilled shale wells, but they also demonstrate that it is likely that future drilling will involve fewer wells than drilled to date. To the extent that more wells are drilled, the liability for decommissioning will also grow that much more.

Summary of wells to plugged

Table 5 below summarizes and characterizes the categories of wells in each state over a two-century legacy from the mid-19th century to the mid-21st to be managed by public policy.[38]

Table 5: Well counts by state and category.

Status		Pennsylvania			West Virginia			Ohio			Total		
					Historical, Existing and Future Wells								
Legacy wells	Unidentified	100,000	to	560,000	9,000	to	66,000	35,000	to	65,000	**144,000**	**to**	**691,000**
	Plugged	71,000			25,000			105,000			**201,000**		
Unplugged non-shale		134,000			70,000			61,000			**265,000**		
Shale	Existing	12,000			4,200			3,100			**19,300**		
	Proved	1,500			1,000			700			**3,200**		
	Non-proved	1,800	to	6,900	1,200	to	4,000	300	to	1,800	**3,300**	**to**	**12,700**
	Total	**320,000**		**785,000**	**110,000**		**170,000**	**205,000**		**237,000**	**636,000**		**1,192,000**

These groups of wells—legacy, unplugged non-shale, and shale wells—differ so much in character and financial strength that a single policy to prevent orphaning of the wells to taxpayers is unlikely to cover the full spectrum, especially because different companies own the different categories.

The legacy well population which might leak in the future is quite large, estimated by the states' regulatory agencies and their records at 345,000 to 892,000 wellbores. It seems unlikely that the previous operator will still be viable if or when legacy wells are found to be leaking. Moreover, regulatory agencies appear to have a weak track record of forcing the burden on operators when they do still exist. Thus, ongoing leaks from these hundreds of thousands of wells are likely to become the responsibility of the state.

Non-shale wells are owned by a large number of small companies, mostly those focused on depleting old wells and not on reinvestment. Given the extremely low productivity of the wells and the extremely slow pace of decommissioning, it is highly likely that these 265,000 wells will eventually be orphaned to the care of the state.

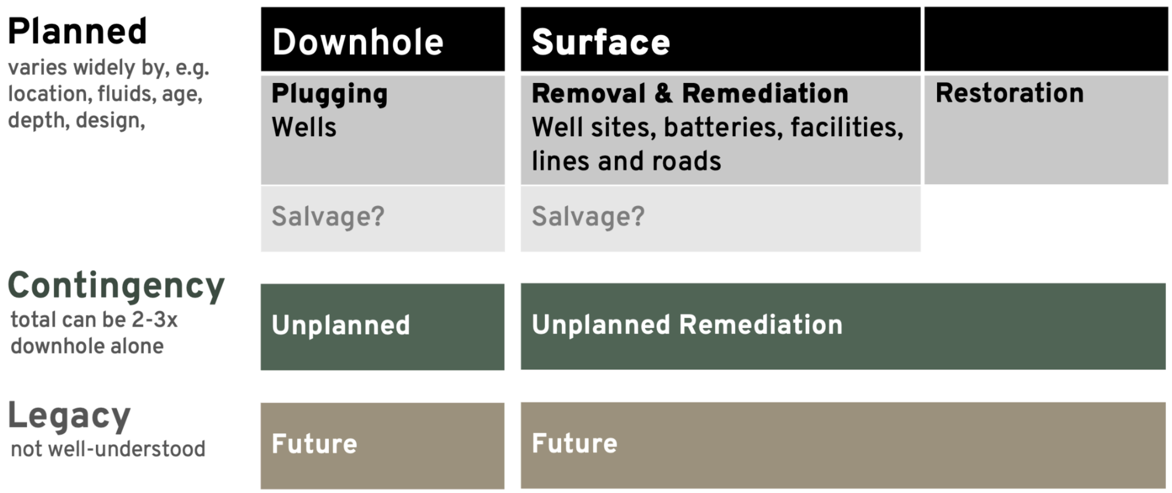
A small number of large companies are reinvesting and collecting profits on shale wells that cost millions of dollars each. Shale companies like EQT, Range Resources, and CNX preferentially own shale wells instead of low-producing non-shale wells. Those shale wells constitute only 7% of unplugged reserves across the three states, but they contribute 96% of producing reserves and all of the future drilling. Without a change in policy, these wells are likely to decline into the same position as non-shale wells. In the meantime, they collectively continue producing high rates and high revenues. In fact, shale companies are already being cited for failing to plug their wells.

WHAT NEEDS TO BE FUNDED

Assuming that policy does intend to clean-up and maintain the long-term security of 641,000 to 1,191,000 wells ultimately located in the three states, planning next requires an understanding of the scope and cost of the work.

To be clear, decommissioning defunct oil and gas producing fields has often been abbreviated as "plugging," and this creates confusion about whether the associated costs pertain only to the downhole work of stopping up the borehole or whether they include the wider, more complicated, scope of decommissioning the surface and future liability. The schematic below summarizes the key dimensions of the full scope of decommissioning work.

Figure 10: Schematic taxonomy of costs for decommissioning upstream oil and gas infrastructure.



Breadth: Plugging a well requires changing the downhole configuration of steel and cement to block the future flow of fluids, and each state sets its own parameters for that final downhole configuration. Mostly, cement blocks about 10% of the borehole, leaving the remainder open but filled with liquids at least initially.

In addition, well sites need to be cleared and cleaned. Flowlines and shared facilities must also be removed and remediated. The three states, unlike some others, require that water drainage and vegetation be restored on sites, including roads that are no longer required.

Complications: Decommissioning comes with surprises. Plugging, remediating, and restoring need to meet defined criteria, and cost estimates are made based on the work that is expected to be needed to meet those criteria. However, surprises occur and drive costs up, rarely saving money. Like all cost estimates, the range of uncertainty is skewed with a long tail of low probability on the high side. In the case of plugging or environmental site clean-up, though, the unexpected high side costs can be many multiples of the expected cost. As a result, for a large group of wells, the average cost will end up significantly higher than the most likely cost planned for. Reported estimates of decommissioning costs often exclude more complicated cases or “unexpected” cost overruns, but for large populations the overruns should be fully expected, along with an average cost markedly higher than the most common cost.

Length: In most locations and at most depths, including the hard rock geology of Appalachia, there is no natural process that will block flow from the hole bored through the subsurface stone. Consequently, the plugging is the primary barrier to potential flow for the remaining future of humanity.

The regulatory prescriptions for well plugging vary across jurisdictions. Although Ohio recently improved its standards, most regulations have stood for decades without update. Meanwhile, the industry was not conducting research to understand how well those designs withstand the test of time. It has become clear in the last ten years that plugged wells do sometimes leak. The frequency and severity are likely to vary greatly by basin and area, and the root drivers are not yet understood. But it is clear that the risk exists and will exist—probably increasing—permanently.

When a plugged well is breached and gas or liquids begin to flow, responsibility becomes a matter of law, and its previous owner stands first in line. Oil and gas companies that remain in business continue to bear liability for problems that develop or are discovered after decommissioning. Of course, many companies of all kinds wrap up their business and close their doors, and many oil companies will not be around to assume responsibility for a subsequent problem, leaving any clean-up to the public.

ESTIMATES OF CURRENT COST

Expectations for the costs to complete the decommissioning of old oilfields in the future build from estimates of current costs, but little is known in the public domain about those costs. The pace of decommissioning is modest nationwide, the costs are mostly private, and disclosures by public companies are limited. We have, however, found data to provide a basis for policy planning for older wells and for shale wells separately. From these data, we estimate an average cost of $120,000 to plug older non-shale wells, and an average cost of between $261,000 and $415,000 to plug shale wells.

It is convenient to measure and report decommissioning costs on a per-well basis, and it is natural to use an average of the per-well costs reported related to decommissioning individual, stand-alone wells. However, it should be noted that there is likely to be a difference of scope between this kind of bottoms-up measurement (which likely does not include costs related to shared facilities and infrastructure) and the kind of grand-total, top-down figure needed for planning (including the full scope of costs). Except for possible savings by program efficiencies, the ultimate cost divided by the number of wells is likely to be greater than the average of individual wells plugged singly during the life of the field or by orphan programs.

Orphan well plugging programs for older wells

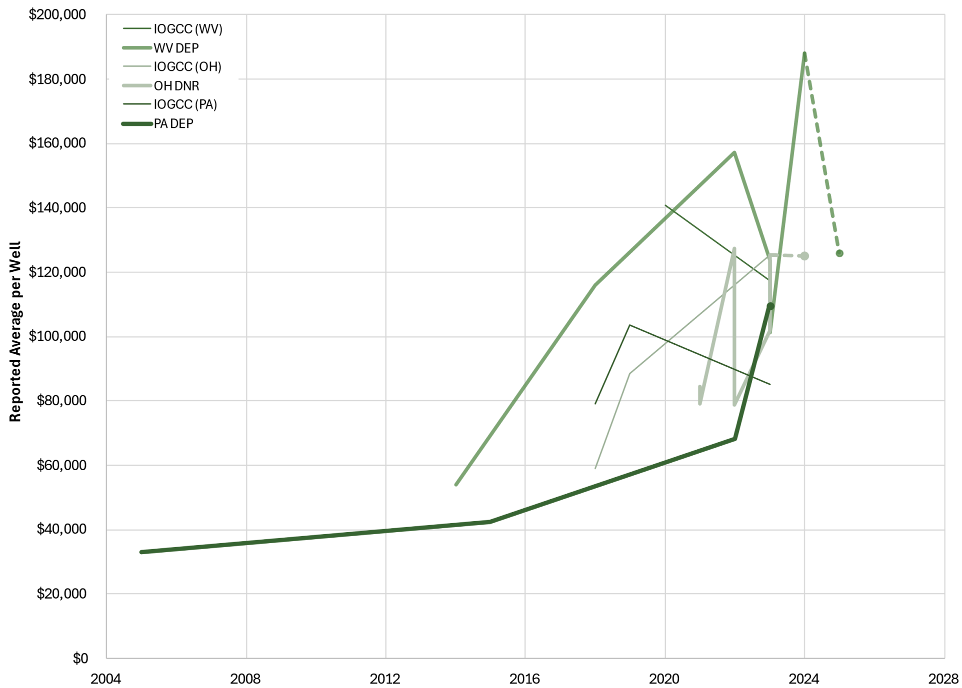
Each of the three states runs programs to decommission orphan wells (without responsible operators), some newly orphaned and some older wells newly discovered to be leaking. Programs had already been plugging wells with their own funds and making reports of historical costs when they made other forward-looking estimates of cost to plug wells with federal funds, and recently the states have provided an interim report on the progress and costs to date. Together these provide a time-series of actual and expected costs for older wells in the states. The programs are likely to have plugged few, if any, newer horizontal wells, and they do not take responsibility for field-level infrastructure.

Figure 11 below shows our calculation of the average cost per well as reported directly by the state orphan well plugging agencies (including in filings related to federal grants) or indirectly in surveys of the agencies published by the Interstate Oil and Gas Compact Commission (IOGCC).[39]

It seems odd that the averages reported in different places by the same programs sometimes have such disparity between the costs, but the most recent figures seem to converge. Still we note a historical pattern that West Virginia tends to run higher than Ohio which tends to run higher than Pennsylvania. The disparity could relate to a number of differences, but it is clear that some of the difference and some of the variation pertains to a difference in scope.

Both Ohio and West Virginia perform the planning function of decommissioning internally when wells are plugged with state funds, so reported costs for state programs include only field operations paid to contractors. However, for wells plugged with federal funds, contractors often perform the planning function and thus bill more per well. In Ohio, a recent audit showed that its internal cost of planning averaged about $17,000 per well,[40] implying that state program costs should be increased by about this amount in order to be complete, but this cost is not added to the figure.

Figure 11: Average per-well costs as reported by state orphan well plugging programs.



Without adjustment for internal planning costs, the most recent data points as reported by the states are summarized in Table 6 below.[41] The large number of wells render more confidence in the figures, and we deem the most recent projected costs to be the best starting point for planning. The graph shows a significant cost increase in recent years. Both the graph and the table suggest that the cost of per-well decommissioning has converged in recent years around about $120,000 per well. Setting aside issues of scope and planning costs to use reported figures directly, we use a cost of $120,000 per well in subsequent calculations.

Table 6: Summary of most recent costs as reported by state plugging programs directly and through IOGCC.

		IOGCC (2024)				**State programs (2023 and 2024)**			
Company		Funds	Wells		**Avg Cost**	Funds	Wells		**Avg Cost**
Pennsylvania	PA	state & federal	138	historical	**$85,290**	federal	224	projected	**$110,000**
Ohio	OH	state & federal	323	historical	**$125,285**	state	323	historical	**$125,285**
West Virginia	WV	state & federal	217	historical	**$117,490**	federal	247	projected	**$125,911**
Total			678				794		

Public filings by Appalachian gas companies for shale wells

Investor filings required by the U.S. Securities Exchange Commission (SEC) provide some insight into the full-scope decommissioning costs of the filing companies—in this case, shale companies. Sometimes the decommissioning costs are reported separately from other capital costs only as figures discounted from some future date, and the disclosures offer little or no information about subtotals of the decommissioning costs across regions or divisions. Consequently, there are few candidate companies that might reveal enough information for us to reverse-calculate an average cost of decommissioning. We did, however, identify two public companies concentrated in Appalachia with useful reports of undiscounted decommissioning costs: EQT Resources (EQT) and Range Resources (Range or RRC).

Table 7 below shows the reported value of "asset retirement obligations" (AROs) for each operator divided by the reported number of gross wells.[42] Over 99% of their combined production in Ohio, Pennsylvania, and West Virginia was from horizontal wells in 2023, and their combined production represented approximately 22% of the natural gas produced from horizontal wells in the three states in 2023. Together, the two report $2.8 billion in liability for 6,749 gross wells, translating to an average cost of $415,000 per well using well count directly from the year-end 2023 10-K filings with the SEC.

That figure is substantially higher than is commonly understood, and a problem may lay in the number of wells.[43] Public data suggests that the operators have responsibility for a much larger number of wells, including some older vertical wells. Using public records of unplugged wells operated by the companies[44] decreases the average cost to $261,000, but this well count includes many non-shale wells.

Table 7: Reported AROs for Appalachian shale producers.

		Undiscounted	Gross Wells to Retire		Cost per Well	
Company	**Ticker**	**AROs**	**per 10K**	per Upstream	**per 10K**	per Upstream
EQT Corporation	EQT	$2,443,000,000	5,199	8,210	$ 469,898	$ 297,564
Range Resources	RRC	$ 358,900,000	1,550	2,514	$ 231,548	$ 142,761
	Total / Average	**$ 2,801,900,000**	**6,749**	10,724	**$ 415,158**	$ 261,274

The discrepancy between SEC-reported well counts and wells reported to state regulators could follow from partial ownership of the larger number of wells, in which case the 10K counts would be more reliable. Or, the difference in count could be older, non-producing wells not enumerated in filings, in which case the larger figure would be more applicable but would include non-shale wells with lower costs. Assuming the higher well count from public data is more descriptive, the average cost drops to $261,000 including non-shale wells.

For subsequent calculations, we mostly utilize a range of costs from $261,000 to $415,000 per well. The fact that the figures are higher than we expected—and the surprising ambiguity of the number of wells reported in SEC-filings—signal the need for much more detailed disclosures about decommissioning liabilities. In the meantime, we can only speculate that the costs may be calculated top-down to include the full scope of all necessary and related work beyond individual well sites.

Total costs

If they ever did, former paradigms about financial assurance certainly no longer apply in Appalachia. Impending costs far exceed assurances.

Table 8 below combines the range of well counts with the range of costs per well to estimate the total current liability faced in the three states. Each row includes a different class of wells. The first and last rows shown in gray represent not actual wells but estimated counts that may potentially require plugging. Certainly not all of the legacy wells will need plugging or re-plugging, and the actual number of shale wells drilled in the future could prove to be significantly higher or lower. Lines in black text represent the quantifiable liability while lines in gray should be heavily discounted for planning purposes.

Table 8: Range of total decommissioning costs faced in Appalachia.
Possible wells shown in gray text; known wells shown in black.

	Wells				Cost	Total Current Costs ($ billion)			
Status	PA	WV	OH	**Total**	**per well**	PA	OH	WV	**Total**
Unidentified wells	100,000 to 560,000	9,000 to 66,000	35,000 to 65,000	**144,000 to 691,000**	$120,000	$12.0 to $67.2	$1.1 to $7.9	$4.2 to $7.8	**$17.3 to $82.9**
Plugged wells	71,000	25,000	105,000	**201,000**	$120,000	$8.5 to	$3.0 to	$12.6 to	**$24.1**
Unplugged non-shale wells	134,000	70,000	61,000	**265,000**	$120,000	$16.1 to	$8.4 to	$7.3 to	**$31.8**
Unplugged shale wells	12,000	4,200	3,100	**19,300**	$261,000 to $415,000	$3.1 to $5.0	$1.1 to $1.7	$0.8 to $1.3	**$5.0 to $8.0**
Future shale wells	1,500 to 8,400	1,000 to 5,000	700 to 2,500	**3,200 to 15,900**	$261,000 to $415,000	$0.4 to $3.5 to	$0.3 to $2.1 to	$0.2 to $1.0 to	**$0.8 to $6.6**
					Current liability	**$20.1**	**$9.8**	**$8.4**	**$38.3**
					Likely new liability	**$0.4**	**$0.3**	**$0.2**	**$0.8**
					Midpoint of Unidentifed and Non-proved	$41.1	$5.4	$6.4	$53.0

Recent research by ProPublica tallied existing financial assurance in each state,[45, 46] and Table 9 below puts that existing financial assurance in context of our estimates of existing liability. For the region, the current cost totals $38.3 billion while existing financial assurance from operators totals only $115 million, 0.3% of the total. The cost of plugging unidentified wells could be even larger, ranging from $17.3 billion to over $80 billion in the upper limit. What is more, the financial assurance is not growing as drilling continues and costs inflate, further eroding the degree of coverage. If policies for financial assurance are intended to protect the taxpaying public from the risk of orphaning, they are falling so far short that they are hardly better than no policy at all.

Table 9: Summary of exposure and financial assurance by state.

Comparison of Liability to Current Assurance	Pennsylvania	West Virginia	Ohio	**Total**
Cost of existing wells	$20.1	$9.8	$8.4	**$38.3**
Existing financial assurance	$0.048	$0.028	$0.039	**$0.115**
Coverage	0.2%	0.3%	0.5%	**0.3%**
Unfunded liability	$20.1	$9.8	$8.3	**$38.2**

EXTRAPOLATION TO FUTURE COSTS

The throng of wells cannot be decommissioned in a single year, and wells that continue producing profitably do not yet need decommissioning. By the time the cost comes due, no profit remains in the well. Operators do not currently set money aside for this future obligation and thus may not be able to pay it when the time comes. Estimation and planning for decommissioning costs must be done now in order to be paid in the future, and that planning must incorporate the additional dimension of how costs change over time.

Wells produce for years, starting at their highest rate and slowing over time. The slow-down is generally a percentage of the rate each year. In an absolute sense, the largest declines come in the earliest years. In shale wells, the pattern is exaggerated, and wells commonly lose 70 or 80% of their rate over their first year of life and almost as much again in the second year.

When rates are high, the operating margins are also high. Wells cost much less to operate each month than they do to drill, and the operating margins must pay back the invested capital plus returns. As a well depletes, margins become thinner, but production rates don't drop as fast in absolute terms. A well can have years of remaining, economically viable life but low margins that make the total profit over those years lower than the volumes might suggest. Years of remaining life and the volume produced during those years can both be poor indicators of remaining profit.

Wells stop producing not when there is no more oil or gas to be had but when there is no more profit. By definition, then, there is no money from that well to fund decommissioning obligations. Even after a well becomes uneconomic to produce, regulations allow it to stand idle often for many years. If the money is not saved from previous operations or diverted from other wells, then the plugging liability is orphaned to the state.

Expect increases in costs

A lot about costs can change over the span from drilling to plugging: mechanical integrity, regulatory requirements, and cost inflation.

Mechanical deterioration

Research has examined but not yet captured predictively the drivers of decommissioning costs; too little data exists in the public domain. As mentioned above, it is clear that the distribution of costs for a population of similar wells is highly skewed, meaning that a small number of high or very high-cost projects drag the average higher than the most common cost. Within a population of similar wells, mechanical deterioration may not change the mode of the distribution of costs, but it is likely to change the high-cost side of the distribution and thus pull the average cost up.

Local corrosivity and other mechanical risks vary widely, and some areas see practically zero deterioration while others suffer severe risks. And deterioration likely has no effect on costs for many years after a well or facility is newly constructed; the first deterioration of virgin pipe has no effect on costs because most integrity remains. The longer a facility operates and the more it ages, the more likely a spill or leak will occur.

It can be expected, and is indicated in research,[47] that as a well sits idle it may deteriorate mechanically and become more likely to encounter unexpected problems and attendant cost overruns when plugging is performed. Given the average age of wells, it seems likely that the increased work necessary to achieve today's decommissioning standards at today's prices will increase slowly with time.

Increasing standards

The unfolding research on plugged wells already shows that some leak after having been plugged to existing standards, and it would be reasonable to expect more robust requirements in the future and thus higher costs to do the additional work. For example, recent research found that over 1,300 wells plugged in West Virginia have been plugged more than once.[48]

For both "conventional" and shale wells, increasing overlap of surface development also may recommend increasing standards for decommissioning. Already suburban expansion has reached out over previous oil and gas production areas, and shale development has reached into the same suburban or exurban areas. As needs for surface use (and potentially for groundwater use) increase, the interaction of old wells and human activity increases and so does the need for protection.

What is more, standards are likely to increase to accommodate the substantially different nature of shale reservoirs which may present more risk of future leaks. Most conventional reservoirs produced historically end life with substantially and uniformly—but not entirely—depleted pressures. The pressure may still be able to flow to the surface, particularly the gas propelled also by natural buoyancy.

However, shale formations deplete partially and unevenly within the reservoir. The extremely low permeability means that substantial remaining pressure at the end of economic life cannot push through the rock quickly enough to pay for ongoing operations, but it remains in the zone farther from the wellbore. At the end of economic life a shale well may recover only 10% to 15% of the gas in place, which means that, over time, the pressure in the wellbore will approach approximately 85% to 90% of the initial pressure when the well first came online. The recharge of pressure occurs very slowly over decades but still within the lifespan of the plugs. Unlike plugs in conventional wells, which must hold back hundreds of pounds of pressure, plugs in shale wells must hold back thousands of pounds of pressure increasing long into the future.

Regulators may also need to adapt plugging designs to accommodate the potential for future development of the same shale formations. The current spacing between drilled wells is optimized for economic value, not for resource recovery. Closer spacing between wells would recover greater volumes but lower profits. Already at the current spacing, it is common for a hydraulic fracture treatment on one well to interact with a nearby well, transferring high pressure fluids to pre-existing wells. In the long future after wells are plugged, it may well become necessary to access the large remaining resources, and new wells would be drilled closer to existing, plugged wells. In order to protect the option for safe future shale development, it would be advisable to plug wells to withstand possible interactions with nearby hydraulic fracture treatments.

Current cost estimates do not contemplate any design more robust than current standards.

Inflation

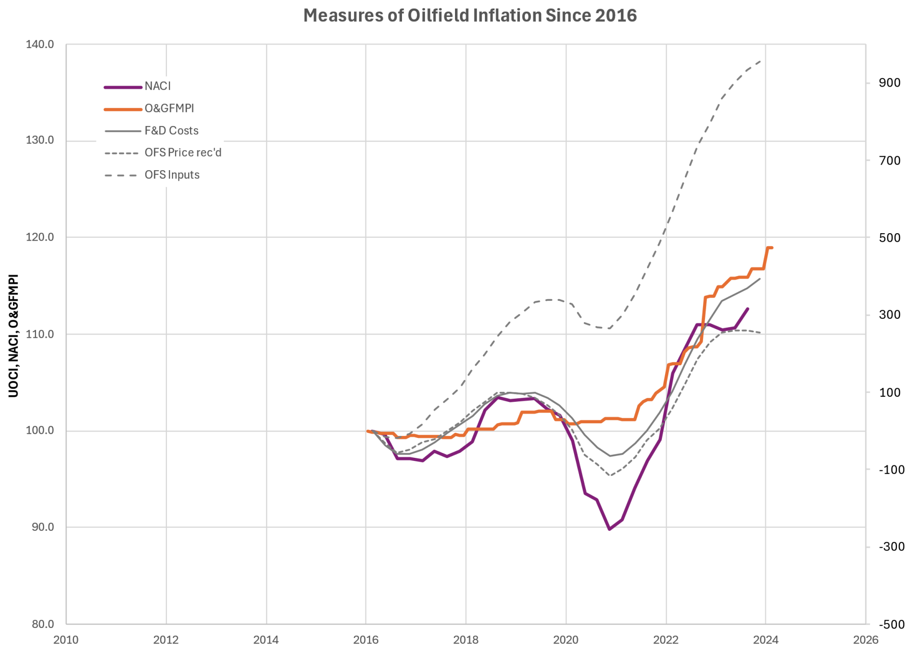
Least ambiguous of future cost increases is the fact that cost inflation affects the oilfield as it does the rest of the economy. Oilfield services partly follow their own supply and demand oscillations, but they also are subject to wider trends. Three public datasets document the progression of oilfield inflation separate from broader inflation, though in different ways over disparate time frames. Still, all three hang together, demonstrating a historical pattern of slow cost growth punctuated by intervals of fast cost growth, though with the possibility of episodes of deflation.

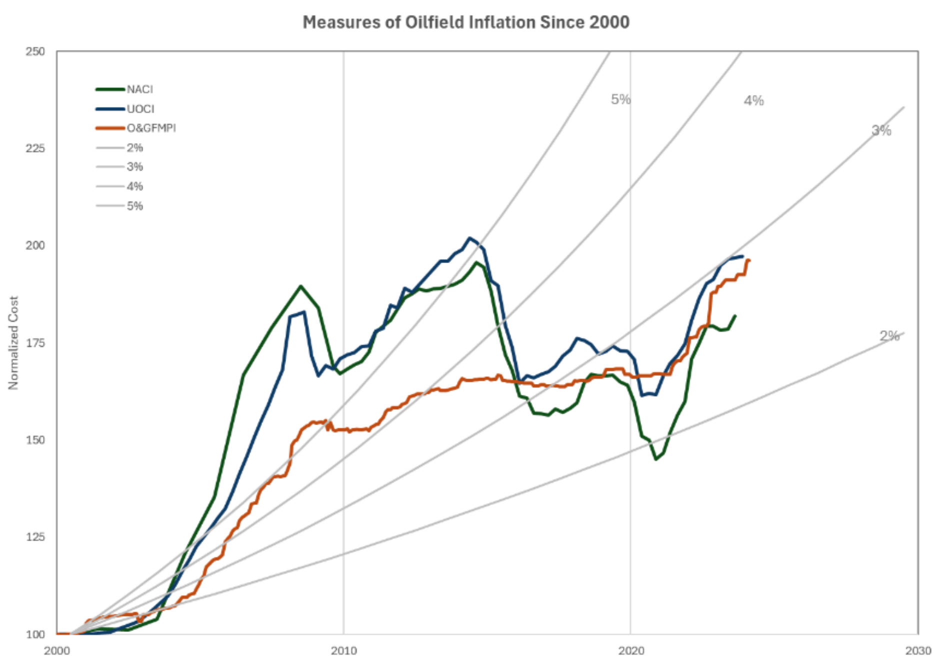
Most on point is nearly 25 years of data compiled now by S&P Global Insights based on surveys of market participants. They report cost indices normalized to the first data in 2000 for North American capital costs (NACI) as well as two broader measures. Longest but less direct is the U.S. Bureau of Labor Statistics' index for Oil and Gas Field Machinery and Equipment Manufacturing, reported for nearly 60 years. More direct but shortest and least quantitative is a quarterly survey by the Federal Reserve Bank of Dallas (Dallas Fed) among oil producers and service companies indicating the direction and qualitative magnitude of changes in costs seen by the companies since 2016.

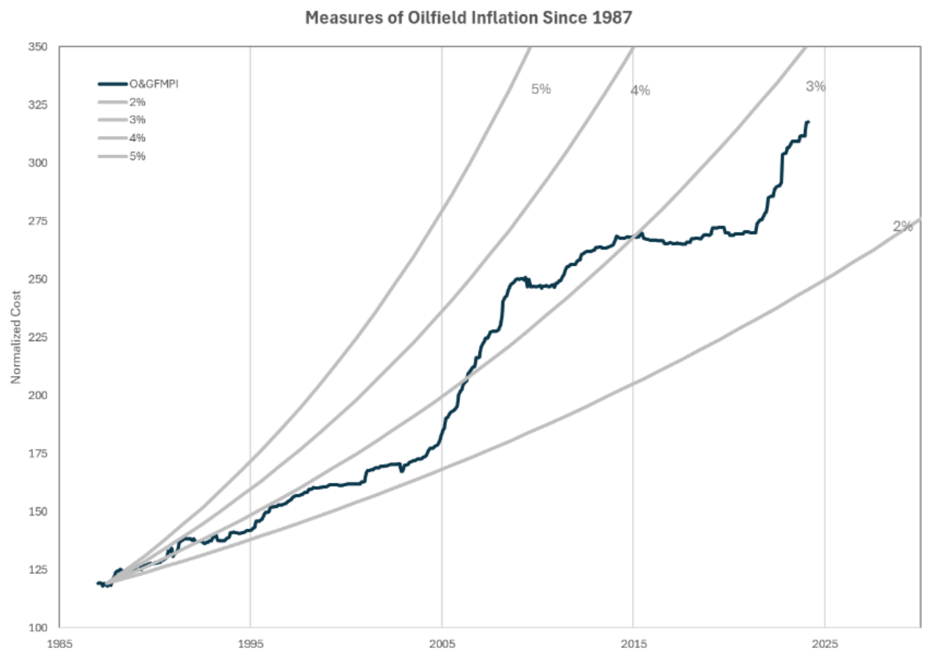
Figure 12 below shows the three sources over four different time scales, zooming out from shortest to longest, each normalized to the cost basis in the starting year. The first graph shows all three sources over about the last 10 years for comparison and corroboration. The second graph shows both of the data sources over the last nearly 25 years again for corroboration and, more importantly, to show longer-term patterns. The last two graphs show the trends over longer time frames.

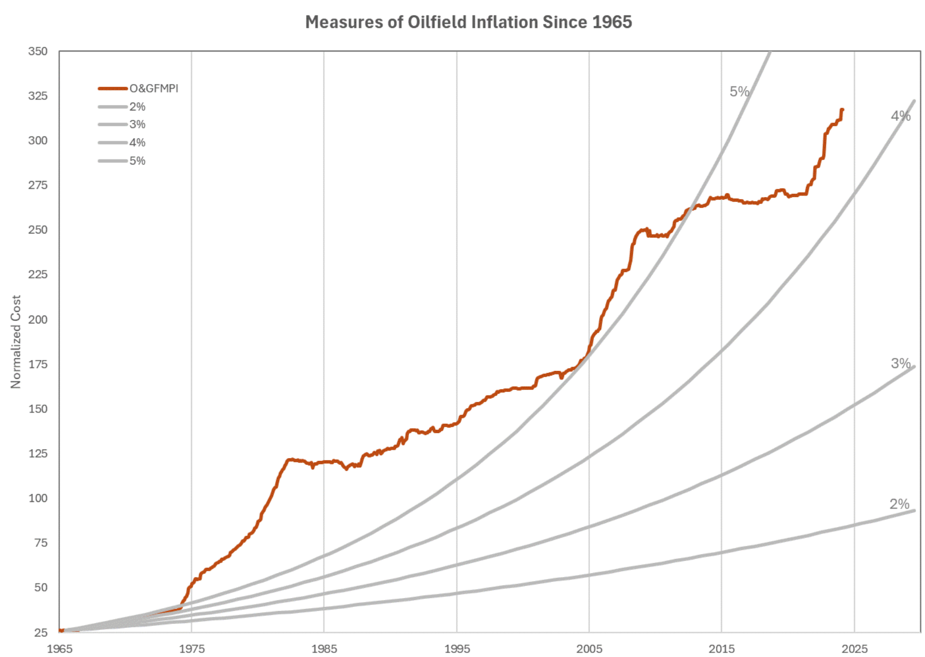
In the first graph, all three data sets show the same behavior,[49] though the BLS data shows less variation from 2016 to 2020. The swings could be less variable because they represent costs that go into providing oilfield services and not the cost of oilfield services directly. Even so, all three show the dramatic inflation well-known in the oilfield over recent years, and all three end at about the same point, suggesting that they are reliable measures.

Figure 12: Comparison of inflation data sources since...









The second graph shows the two quantitative inflation measures from the year 2000. Again, the BLS data does not show the downswings but does capture the upswings and ends at a similar point after two episodes of inflation, suggesting again the validity of the less-direct BLS measure. The graph also shows trends representing constant inflation rates of 2% to 5% compounded annually. Over this span, the compound average is nearly 3% per year, though with periods of higher and lower inflation.

The third and fourth graphs show only the BLS data but over longer time frames. The last graph shows the full dataset available, and the third graph shows a subset to exclude the oldest and largest inflationary episode. The 60-year data shows that inflation in the 1970s caused the compound average to remain over 5% for most of history.

Normalizing to 1987 removes the 1970s inflation and picks up from (what the BLS shows to be) a more stable point, resulting in a long-term average between about 2.5% and 3.5%.

All of the data and all of the time frames show the same thing: intermittent episodes of high inflation separated by periods of slower or even negative growth. The most recent episode appears to have been driven by economy-wide inflation, but the previous episode in the late 2000s appears to have been driven by increased demand for oilfield services related to the shale revolution. The most profound inflation occurred in the 1970s and early 1980s when increased oilfield demand compounded with economy-wide inflation and more than tripled oilfield costs in 10 years.

Thus, data over the last 40 years suggests a long-term average of around 3% per year, though it depends heavily on the starting year and the severity of each inflationary episode. It is worth noting that annual surveys by the Society of Petroleum Evaluation Engineers (SPEE) of people performing economic projections and evaluations have commonly reported similar expectations. Continued inflation in the near term could drive up the future average, and the SPEE survey responses from 2024 suggest expectations of a little more cost inflation in the near term. It should also be noted that the most comprehensive data includes the widest range of conditions including an uncommon combination of pressures that pushed the long-term average markedly higher.

More concretely and specifically, Weber (2021) studied 30 years of contracts for well plugging under Pennsylvania's state program from 1989 to 2020, before most of the recent inflation. He found an average nominal growth rate of 5.6% per year (3.2% real cost growth), but he also observed a marked increase in cost coincident with the state's change of plugging standards in 2012, which could contribute to cost inflation. The compound nominal growth in the previous 23 years came to about 5.4%.[50]

The average inflation over the next decades will depend heavily on the near-term inflation. If the current episode has concluded, then the slow growth paradigm will dominate, and the average will be lower. However, if the episode continues, then the average will be higher. The following table shows a range of multipliers to convert present cost estimates to future costs with a range of assumptions. For example, 20 years of escalation at 4% would turn today's cost of $120,000 into a nominal cost of $263,000.

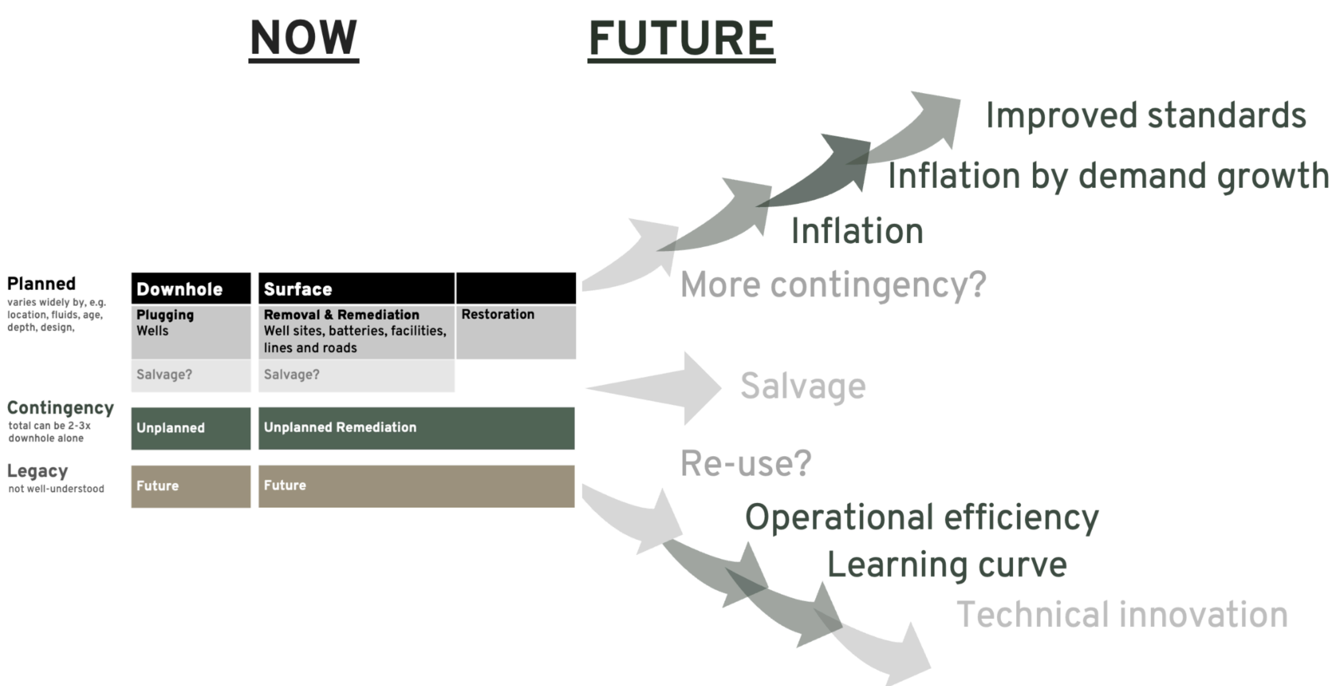
Table 10: Conversion of present cost estimates to future costs for ranges of horizons and compounding growth rates.

	Value multiplier assuming inflation rate of			
Delay	2%	3%	4%	5%
10 years	1.22	1.34	1.48	1.63
20 years	1.49	1.81	2.19	2.65
30 years	1.81	2.43	3.24	4.32

Hope for decreases

Countervailing trends might offset the forces of increasing costs, though they offer less hope. Some depleted wellbores might be repurposed to generate other revenue to fund decommissioning. Operational efficiencies and learning-by-doing might reduce the costs, and some have argued generically that the mystic forces of innovation might reduce costs. The schematic in Figure 13 depicts the upward forces described above and the potential downward forces described here.

Figure 13: Schematic of forces affecting decommissioning costs in the future.



Salvage

Decommissioning involves removing equipment and often some pipe from the location, and in some regions this hardware has historically had some value for re-use or for scrap. However, in recent years in most locations, salvage value has been minimal or non-existent. The demand for used equipment has been waning as growth has abated and changed, and the value of equipment tends to diminish as it ages. It seems highly unlikely that salvage value will significantly offset decommissioning costs in the future, especially from the non-shale wells in Appalachia.

Re-use

Some people hold hope that some wellbores can be repurposed for new economic purposes, especially as energy storage and low-temperature geothermal applications, but the technologies remain unproven. At best, the technologies have been demonstrated with limited pilot projects; to our knowledge, none have yet been deployed commercially. Even if the wells are re-purposed, they will have to be partially plugged at deployment then fully plugged at the end of economic life. So the same fundamental costs and drivers apply.

Operating efficiencies and learning-by-doing

It is likely that a concentrated, optimized decommissioning program can be optimized for efficiency like other repetitive processes. About half of all documented wells in the U.S. have already been plugged, providing a learning experience, but mostly not in large programs. As discussed below, plugging and remediation are mostly simple mechanical processes. The potential scale of improvements has not been studied rigorously, but it is almost certainly smaller than the upward pressures in part because, unlike cost inflation or increasing standards, cost savings from efficiencies diminish over time.

Innovation

Innovation has a long and venerable history generally, but plugging and other decommissioning processes are mostly simple mechanical processes, namely pumping cement into a hole in the ground. It is already a low-cost methodology, and it is not the kind of process susceptible to improvement by electronics or software (apart from planning). More importantly and due to the simple and low-cost nature of the established process, there has been very little research in recent decades on plugging techniques, and that research has focused on improving quality, not on reducing costs.

On balance

Long-term planning to pay for costs should consider how those costs will change by the time they must be paid, and it is highly likely that actual costs will be greater when they are paid. Decades of documented inflation in the past point to continued inflation as the work is performed in years and decades to come. Plus, more qualitative upward pressures exceed the potential savings downward. To be effective, a new policy must plan to meet the risk of increasing cost.

CONCLUSION

Hundreds of thousands of wells in Appalachia are functionally insolvent, unable to pay tens of billions of dollars of clean-up obligated to landowners and the public. Plus, hundreds of thousands of additional legacy wells may turn out to need plugging as they are found to be leaking. These costs are poised to fall on taxpayers of the region. The size of the problem makes any solution difficult and painful, but it is easier to solve the problem now than it will be in the future. The good news is that there is only one viable solution without burdening the public. Part II examines how to make it happen.

ENDNOTES

1. (Olalde, 2024; Schuwerk & Rogers, 2020a, 2020b)

2. (Purvis, 2023, 2024; Purvis & Purvis, 2023)

3. We do undertake to recount or quantify those risks, but we do premise our analysis on the long-standing requirement that oil and gas companies should securely decommission their wells and equipment at the end of economic life.

4. For the purpose of this analysis, we use the term "abandoned" to mean resolved by its operator. The term is sometimes applied to wells that remain unplugged but neglected by their owners. We count those among the separate group of unplugged wells. The term is also sometimes used to refer only to wells left behind before modern standards of plugging.

5. Often, some records exist about the number of wells drilled in a state even when they are not listed. Though there is some documentation to suggest that they exist, little is known about them. They are sometimes called "undocumented," but because there is documentation that they were drilled, we prefer to call them "unidentified."

6. (Kang et al., 2016)

7. (Riddick et al., 2019)

8. For this and other figures, we have combined the production of oil and gas into an equivalent value of gas ("Mcfv") on an approximate value equivalence of 1 barrel of oil (bo) equal to 20 thousand cubic feet (Mcf) of gas.

9. It may be noted that development of a new formation is unfolding quickly in Ohio using vertical wells and may contribute to overall growth in the future. Those wells are included within the fraction of wells in the region that are not stripper wells.

10. (Weber et. al., n.d.)

11. (Hess, 2022)

12. (Hess, 2024b)

13. (Hess, 2024c)

14. (IDLE AND ORPHAN OIL AND GAS WELLS: STATE AND PROVINCIAL REGULATORY STRATEGIES Supplemental Information on Orphan Well Plugging and Site Restoration, 2024)(IDLE AND ORPHAN OIL AND GAS WELLS: STATE AND PROVINCIAL REGULATORY STRATEGIES Supplemental Information on Orphan Well Plugging and Site Restoration, 2024)

15. (Energy Information Administration, 2024)

16. A previous researcher found the shut-in rate to be higher than 50%. (Patzek et al., 2019)

17. (Saputra et al., 2024)

18. Boettner, 2025

19. (Hess, 2024b, 2024a, 2025; Oil and Gas Compliance—Report Extracts, n.d.)

20. (API | Natural Gas, n.d.; Home—American Gas Association, n.d.; Lance, 2024)

21. (Frequently Asked Questions (FAQs)—U.S. Energy Information Administration (EIA), n.d.)

22. It is also worth noting that the pace of production to resources varies among basins and that the Appalachian basin has a proportionally larger relative supply than the national average.

23. Note that its website www.potentialgas.org remains more than four years out of date as of May 1, 2025.

24. (Carter, 2023)

25. “Speculative resources” in the language of the study. (Carter, 2023)

26. They use the average of the range of outcomes despite the technicians’ description that the lower “most likely” number is more representative. The authors explain, “Note that the ‘most likely’ values for any given province represent the best judgment of individual PGC members at the time of preparation and are considered the most credible estimates for purposes of analysis, planning and exploration.” The preface to the study concludes with this sentence, “The Committee cannot stress too often the importance of understanding the differences between the ‘most likely’ and ‘mean’ value datasets.” (Carter, 2023)

27. (Assumptions to the Annual Energy Outlook 2025: Hydrocarbon Supply Module, April 2025, 2025)

28. Figures have been compiled from the EIA’s reports, e.g. (Energy Information Administration, 2024).

29. (Assumptions to the Annual Energy Outlook 2025: Hydrocarbon Supply Module, April 2025, 2025)

30. (Annual Energy Outlook 2025—U.S. Energy Information Administration (EIA), 2025)

31. Note that the forecast starts in 2025 while reserves represent the first of 2023. To combine the two, we ignore actual production of the two years in between and assume that those volumes were replaced by newly proved reserves.

32. (Dang, 2025)

33. (Pioneer Natural CEO Scott Sheffield on Trump’s Tariffs, Impact on Steel Business and Oil Prices, 2025)

34. Note that we have shown production only from horizontal wells. The Barnett Shale in particular produced from many vertical wells, but these are less analogous to current development in Appalachia.

35. Note that the graph does not include the other major gas shale, the Haynesville shale.

36. (Boswell, 2021)

37. It may be noted that, despite the intended confidence in the volumes, the proved volumes in practice often suffer downward revisions.

38. It should be noted again that Riddick (2019) concluded that West Virginia has between 166,000 and 862,000 wells, and that the well count in Ohio looks too low by comparison to the sibling states.

39. (IDLE AND ORPHAN OIL AND GAS WELLS: STATE AND PROVINCIAL REGULATORY STRATEGIES Supplemental Information on Orphan Well Plugging and Site Restoration, 2024; IDLE AND ORPHAN OIL AND GAS WELLS: State and Provincial Regulatory Strategies Supplemental Information on State Prioritization Systems for Orphan Wells, 2023)

40. Ohio Auditor of State, 2022, “Ohio Department of Natural Resources, Orphan Well Program, Performance Audit (August 2022)”. https://ohioauditor.gov/performance/odnr_orphan_wells.html

41. It may be noted that West Virginia did report more recently a small program of 15 wells averaging $188,000 per well.

42. Range Resources Corporation, SEC Form-10-K, 2023, page 8 and F-37 (p 100). Accessed on September 13, 2024: https://ir.rangeresources.com/static-files/57bf4e97-9f49-4c1a-8209-f1c01a08b352

43. It may be noted, though, that a previous bill in Pennsylvania proposed requiring bonds of $400,000 per shale well.

44. For this and other reports of production data through the state regulators, we rely upon The Capitol Forum’s Upstream database.

45. (The Rising Cost of the Oil and Gas Industry's Slow Death—ProPublica, n.d.)

46. Note that we have not attempted to quantify state and federal taxpayer funds already expected to be available under existing programs for decommissioning orphan wells.

47. E.g. (Raimi et al., 2021)

48. (Boettner, 2025)

49. It should be noted that the Dallas Fed figures suggest only direction and relative, not absolute, magnitude. We have scaled those figures to compare with the other patterns.

50. The author does not present a nominal growth rate before the change in standards. He does report real growth of 3.0% for the early decades compared to 3.2% overall, and he does report 5.6% nominal growth overall. The fact that the change in standard occurred so late in the timeline means that it has less effect on the annualized compound growth over the whole period.

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