# Cutting Costs or Cutting Corners: Ownership across the Life Cycle of Oil and Gas Wells

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**Abstract**

Across the U.S., there are millions of non-producing, unplugged oil and gas wells. Moreover, the majority of oil and gas wells produce very little output, with a median annual revenue below $100,000. Policymakers have increasingly expressed concern about who will pay for end-of-life clean-up costs for this large stock of aging wells. These concerns are exacerbated by the fact that hundreds of thousands of aging wells are owned by small firms who may not be able to afford end-of-life costs. In this context, we document patterns of oil and gas well ownership across the life-cycle. We show that wells are traditionally sold to progressively smaller firms as they age. We then build a model of well operations, showing that this progression can arise from specialization across firms in well type, but it can also arise as owners sell off to small firms that declare bankruptcy to offload environmental liabilities. We conclude with policy implications related to well plugging, bonding requirements, and decarbonization.

Keywords: oil and gas wells, judgment-proof problem, energy transition, financial assurance, bonding, orphan wells

JEL Codes: G33, G34, L25, L71, Q35, Q58

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# 1 Introduction

Across the United States, over two million derelict oil and gas wells no longer produce anything yet have not been permanently sealed off. These wells pose risks of groundwater and soil contamination, local air pollution, methane leakage, and even explosions (Kusnetz, 2011; Borenstein and Kellogg, 2021; Mider and Adams-Heard, 2021; Kang et al., 2023). Hundreds of thousands of these wells are additionally "orphaned" – there is no existing firm responsible for the well's plugging, and no company liable in the event of contamination, because the past owner cannot be traced or has gone out of business. Policymakers have increasingly focused their efforts on potential solutions. The Bipartisan Infrastructure Law provides nearly $5 billion for orphaned well cleanup (U.S. Department of the Interior, 2023) – although it notably leaves unaddressed the mechanisms by which additional wells could become orphaned in the future.

The scale of the orphan well problem reflects the fact that at the end of their productive lives, many low-producing wells are owned by small, poorly capitalized firms. Few of these wells were originally drilled by such small operators; instead, they were acquired by their final owners through an active secondary market. This paper builds the first large-scale historical dataset on changes in well ownership and uses the data to provide new facts and empirical results about this important market. The data confirm and quantify the conventional wisdom that wells move systematically towards smaller operators as production decreases.

We also explore the crucial question of *why* this pattern of ownership transfers occurs. One explanation put forward by environmental groups and local media outlets is that the value proposition for these acquisitions depends (explicitly or implicitly) on the fact that the smaller operator can avoid liability for eventual required cleanup (Mider and Adams-Heard, 2021; Jaffe and Najmabadi, 2022; Olalde, 2022; Lutz and Rowland-Shea, 2023).[1] Such transfers would be win-win for large and small producers and present a route for even deep-pocketed companies to cheaply shed cleanup liability. An alternative explanation favored by industry is that differences in the production process across the decline curve mean that wells of different ages can be most efficiently operated by different types of operators. In this story, major international drilling firms specialize in capital-intensive new production while small local operators take advantage of low-cost labor or other factors to maximize the value of production from simpler-to-operate marginal wells (National Stripper Well Association, 2014; IPAA and AXPC, 2016). These competing explanations imply different solutions for policymakers interested in balancing environmental goals and the value of resource produc-

[1] A related but somewhat separate point is that oil and gas majors, which are facing increasing levels of regulatory and public scrutiny for the carbon dioxide emissions from their product, may increasingly sell off wells to be able to make claims about climate action. We speak to this below.

tion. While not ultimately dispositive, our results provide some of the first evidence on the relative plausibility of the liability-shielding vs. specialization arguments.

To understand these claims made by environmental advocates versus those made by oil and gas industry advocates, we assemble a novel dataset of well ownership across four major oil and gas producing states. We first show that: lots of wells are sold, and some wells are sold many times – although the academic literature has focused very little on the reasons for, and effects of, these transfers. Second, we show that the median US well is low-producing, and that while the related literature largely focuses on initial drilling decisions, understanding the behavior of low-producing wells is crucial for understanding the current state of the industry.

We next document patterns of ownership transfer across the well life cycle, providing novel empirical evidence that (1) wells are more likely to be sold as expected future profits decline; (2) *wells* with low expected future profits are more likely to be sold to *firms* with low expected future profits; and (3) well sales at mid-life are correlated with some long-run outcomes. In particular, we show that production at some aging wells increases after a sale, consistent with industry claims that some firms specialize in extracting additional oil and gas out of end-of-life wells. However, we also observe that plugging is less likely at non-producing wells after sales, consistent with environmental advocate claims that sales allow firms to discharge their environmental liabilities, leaving state governments on the hook for clean-up.

To reconcile these competing claims, we build a model in which firms specialize in particular production levels, such that asset transfers across well ages increase allocative efficiency. The model also allows for the judgment-proof problem: firms can declare bankruptcy and thus avoid environmental liabilities. The model yields several predictions consistent with our empirical facts. It also points to policy implications. We thus calibrate the model to be able to provide policy guidance on two crucial questions: given the observed patterns of well transfers and long-run outcomes, are policies that requiring bonding upon asset transfer likely to increase or decrease social welfare? And, are there observable well or operator characteristics that regulators might target when designing regulations relating to well transfers?

This paper contributes to several strands of the literature. It is most closely related to the literature in both law and economics on the judgment-proof problem, which refers to the idea that firms in a limited liability regime do not fully internalize the expected costs of risky behavior, given the option to declare bankruptcy. Boomhower (2019) shows that changes in bonding requirements caused significant changes in the structure of Texas's oil and gas industry, consistent with the judgment-proof problem having important impacts on environmental and safety outcomes. Gerard (2000); Mitchell and Casman (2011); Davis

(2015); Lange and Redlinger (2019); Macey and Salovaara (2019), and Yang and Davis (2021) also look at policy solutions such as bonding requirements in theory and in practice. Other papers in this literature look at the relationship between firm size and environmental outcomes (Eyer, 2018; Cohn and Deryugina, 2018). We extend this literature to focus on the role of asset transfers specifically. A key prediction from our model is that in industries where asset transfers are common, it is not *just* the small, under-capitalized firms that we typically think of as "judgment-proof' that are able to socialize risks and end-of-life liabilities – larger firms can extract some of the associated surplus as well. A closely related idea is "contracting out" in the law and economics literature, whereby large firms obtain inputs with significant potential liabilities from outside the boundaries of the firm (Ringleb and Wiggins, 1990; Brooks, 2002).

Second, our paper relates to a literature across economics, engineering, and policy that has examined abandoned and orphaned wells, focusing especially on estimating the total number of orphaned and abandoned wells; on documenting the risks associated with unplugged wells; and on estimating the costs of plugging wells (Kang et al., 2014; Muehlenbachs, 2015; Ho et al., 2018; Kang et al., 2021; McClure, Simonides and Weber, 2022; Raimi et al., 2021; Boutot et al., 2022; Harleman, Weber and Berkowitz, 2022; Kang et al., 2023); we contribute an understanding of how the structure of the industry has contributed to the present large stock of abandoned wells as well as policy implications going forward.

Third, our paper relates to literature on the reallocation of capital across its lifecycle. Existing research has documented that capital reallocation represents a substantial portion of overall investment and that young and small firms are more likely to purchase used capital while older and larger firms are more likely to purchase new capital (Eisfeldt and Rampini, 2007; Eisfeldt and Shi, 2018; Ersahin, 2020; Ma, Murfin and Pratt, 2022). The pattern of well transfer that we document is consistent with this more general phenomenon. This literature has largely focused on credit constraints facing young and small firms as the underlying mechanism, finding that stronger rights for contractual creditors effectively decrease the cost of new capital for small firms (Ersahin, 2020). Drawing on the law literature, we focus on obligations to "involuntary creditors," such as tort creditors after an environmental accident (Macey and Salovaara, 2019). In our model, stronger protections for involuntary creditors would also drive small firms away from older capital, in this case by increasing the cost of old capital.

Our paper relates to a large literature on the economics of oil and gas production (Kellogg, 2011, 2014; Anderson, Kellogg and Salant, 2018; Newell, Prest and Vissing, 2019; Newell and Prest, 2019; Herrnstadt, Kellogg and Lewis, 2024). Many of these papers have focused on initial exploration, drilling, and early production decisions. In contrast, we focus on

the economics of oil and gas production until the end of life. Two notable exceptions are Muehlenbachs (2015) and Weber et al. (2021), which focus on the decisions operators make towards end-of-life, but which do not address transfers.

Finally, we contribute to policy discussions on aging infrastructure and sunk assets during an energy transition (van der Ploeg and Rezai, 2020; Davis and Hausman, 2022; Purvis, 2023; Im, 2023). We argue that understanding the historical patterns of asset transfers in the oil and gas industry, particularly for wells with low profits, is crucial for navigating decarbonization policy.

This paper provides as follows. Section 2 provides contextual background. Section 3 documents the data we assemble, and Section 4 provides empirical results. In Section 5 we develop a theoretical model, with calibrations and policy implications in Section 6. Section 7 concludes with directions for future work.

# 2 Institutional Background

A well-documented property of oil and gas wells is that initial production volumes are high, but production falls rapidly as geologic pressure declines (Kellogg, 2014). Production may then continue at low levels for decades, as we document below. During this period, minimizing production costs is essential to well profitability (Inkpen and Moffett, 2011). Then, at the end of a well's productive life, state regulations require that operators plug wells. One state regulator explained to us that public records on well plugging are likely to be reasonably comprehensive, given operators' strong incentives to ensure that plugging activity is recorded by state regulators.

Recent estimates of the cost of plugging end-of-life wells have varied. One recent set of estimates using data from almost 20,000 oil and gas wells found plugging costs ranged from $3,422 to $37,038, or $7,620 to $159,764 for plugging and site remediation (Raimi et al., 2021). This heterogeneity stems in part from differences in site characteristics: well age, site terrain, and especially well depth are associated with higher plugging costs. State regulations around plugging, the number of wells being plugged in a geographic area (to enable economies of scale), and oil versus gas well type can also influence plugging costs (Raimi et al., 2021). One implication of the cost of plugging wells is that operators may find it profitable to continue deferring plugging into the future, even if wells are producing very little or zero oil and gas (Weber et al., 2021).

There are many components of the social cost of leaving a well unplugged. Multiple studies have documented higher average methane emissions at unplugged wells than plugged wells, while also noting that a small number of unplugged wells contribute a disproportion-

ate share of overall methane emissions (Kang et al., 2014; Townsend-Small and Hoschouer, 2021).[2] Unplugged wells also pose a risk of groundwater contamination, which is capitalized into nearby land values (Harleman, Weber and Berkowitz, 2022). Additional social costs that have not yet been well quantified in the existing literature include emissions of local air pollutants such as benzene and volatile organic compounds (VOCs); soil contamination; ecosystem impacts; and explosion risk; (Kang et al., 2021; Raimi et al., 2021).

To incentivize operators to plug wells, thereby reducing these potential damages, states require operators to provide some form of financial assurance (e.g., a bond) to ensure funds will be available for end-of-life cleanup costs. Though specific bonding requirements vary by jurisdiction, researchers and environmental advocates generally agree that existing bond requirements are too low relative to actual end-of-life costs, and therefore existing bond policies provide inadequate incentives to ensure that wells are eventually plugged (Ho et al., 2018; Yang and Davis, 2021). Bonding requirements have evolved over decades, and state regulators are actively exploring potential reforms.

# 3 Data

To study changes in well ownership, we assemble a rich panel dataset from state regulators in four major oil and gas producing states: California, Colorado, Pennsylvania, and Texas. Data from state regulatory agencies is necessary because commercial datasets with nationwide coverage, such as Enverus, do not maintain past histories of well owners. These four states, however, maintain a history of well ownership, which is necessary for identifying asset transfers. State regulators collect information on well ownership, production levels, and plugging status for both tax and royalty purposes and environmental monitoring.

Our state selection is necessarily limited by the fact that many states do not make past ownership histories available. Nonetheless, these four states represent around half of US production;[3] they cover major conventional and unconventional oil and gas regions such as the Permian basin and Marcellus formation; and they allow us to examine both regions with declining production and a large number of aging wells (notably, California) and areas with a mix of newer and older wells (such as Pennsylvania). Our panel is unbalanced, based on what time periods have been made publicly available by state agencies: California covers

[2]Researchers have also noted that well plugging, on its own, is not a panacea for methane emissions, as plugging regulations were not generally designed with the goal of minimizing methane emissions. In coal-producing areas, for example, plugged wells may be vented for safety reasons, leading to significant methane emissions even from plugged wells (Kang et al., 2014).

[3]Together, they make up 52 percent of oil production and 45 percent of gas production over 1993-2023; over 2020-2023, the percentages are higher: 58 percent and 52 percent.

1977-2023; Colorado 1999-2021; Pennsylvania 1997-2023;[4] and Texas 1993-2021.

The data cover monthly oil and gas production; well-level characteristics such as location; operator history; and plugging status. We augment these state-level data with oil and gas prices from the US Energy Information Administration. For natural gas, we observe both Henry Hub prices and citygate prices; for oil, we observe both West Texas Intermediate prices and first purchases price.

A time series of production from each states is shown in the Appendix. Our observed oil production closely matches annual totals reported by the EIA. Across the four states, we see a range of patterns across time: California oil production peaked in the mid 1980s and has steadily declined. In contrast, Colorado and Texas oil production has sharply increased since around 2010. In Pennsylvania, we see low oil volumes overall.[5] For gas production, our totals do not match quite as well, but we are generally within 5% of the annual totals reported by EIA, and the state-level time paths of our variables matches what is reported by EIA. Just as with oil production, California has seen a steady decline, whereas the other three states have seen an increase: a gradual increase over time in Colorado and Texas, and a sharp increase post-2010 in Pennsylvania.

Summary statistics at the well-by-year level are also provided in the Appendix. We show both mean and median values, because some of the variables (notably production quantities and revenues) show significant skew. The observation has a mix of oil-only, gas-only, mixed oil and gas, and zero-production wells. Our time period covers periods with both high and low oil and gas prices. More detailed descriptive facts, on variables of interest such as sale frequency, are provided below.

We note that assembling the four different states into one panel requires harmonizing some data definitions across the various reporting agencies. Here we briefly describe these; additional details are provided in the Data Appendix. First, we note that in Colorado, Pennsylvania, and Texas, we identify operator transfers based on changes in the unique operator identifier within a state over time. In California, in contrast, we have a dataset of operator transfers. Second, the four states have slightly different reporting conventions for natural gas liquids and condensate. Third, although for simplicity we refer to a well as the unit of observation, the Texas data are at the lease, not API level. Fourth, we do not observe plugged status in Texas. Finally, for conventional wells in Pennsylvania, we observe production at the annual, not monthly, level.

[4]Earlier data are available for Pennsylvania on the state agency's website, but they appear to be incomplete: annual state-wide production totals do not match totals in EIA reports. We were unable to obtain more complete data for the earlier years.

[5]The jump up in recent years is driven an increase in condensate from unconventional wells (reported jointly with oil in Pennsylvania).

In some specifications, we report results as a function of well age. For 44% of wells, we calculate this as time since first production. For some wells, first production occurs prior to the start of our dataset. For these "truncated" well histories, we calculate age as spud data where reported (11%). However, spud data is frequently missing. To calculate age for wells without a recorded spud date, we interpolate the spud date based on the fact that API numbers are assigned sequentially within a county. This interpolation covers 16% of wells; for the remaining wells we do not observe enough wells within that county to be able to interpolate the spud year.

# 4 Empirical Results: Motivating Facts

We next turn to an empirical investigation of transfers across the well lifecycle.

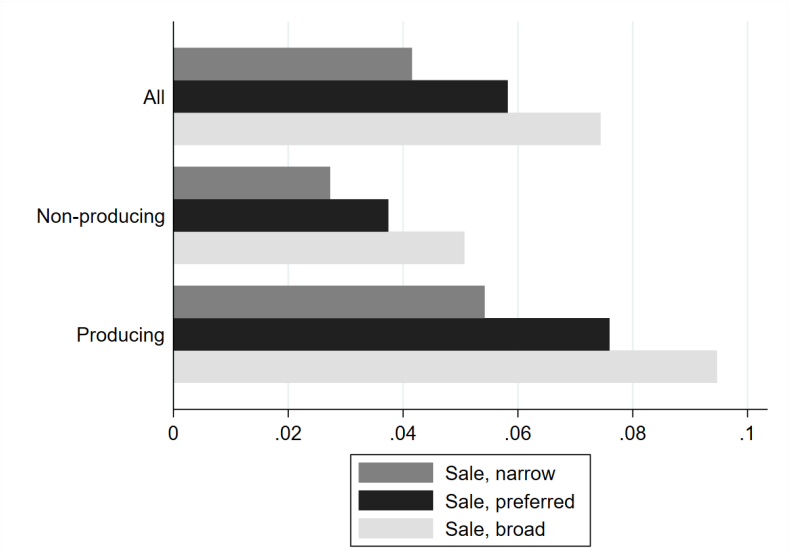
## 4.1 Well sales are common

Empirical analysis of asset transfers is largely missing from the economics literature, so we begin by providing descriptive evidence on the frequency of well transfers. We first document that asset transfers are observed frequently in the data: this finding is important both because it suggests that transfers are an important component of oil and gas markets and because it implies that we have statistical power for additional empirical analysis.

Figure 1 shows that wells are frequently sold. The top three bars show the frequency of sales in a year across all wells; the remaining bars separate the wells into non-producing and producing wells. For each set of wells, we consider three definitions of a sale, all inferred from a change in the operator identifier from one year to the next. Our preferred definition, in black, counts as a sale any change in operator *except* where the old and new operator names are similar (e.g., Diversified Oil & Gas LLC and Diversified Production LLC) and where the well transfer was part of a prominent merger (e.g., Chevron-Texaco in 2001). We do not consider these sales to be "typical" as they may be driven by company-wide strategic decisions (including, for example, decisions related to exploration, drilling, and even refining), as opposed to decisions regarding individual wells. The top black bar shows that the typical well experiences 0.058 sales per year, or around one sale every 17 years. (The sale variable allows for multiple operator changes in a year, as we observe this information at the monthly level for most wells; nonetheless, it typically takes on a value of zero or one, so this can be interpreted as implying that around 6% of wells experience a sale in a given year.)

We also consider, here and throughout our analysis, two alternative definitions of a sale.

Figure 1: Wells Are Frequently Sold




Note: Each bar is the sample-wide average value across 14.4 million well-by-year observations. The panel is an unbalanced panel covering California, Colorado, Pennsylvania, and Texas; details in text. Using our preferred definition of a sale, the typical well experiences 0.058 sales per year, or around one sale every 17 years. The preferred definition of a sale is a change in ownership where the old and new owner names are not too similar and notable mergers (e.g., Chevron-Texaco) are not included as sales. The broad definition includes sales of similarly-named firms as well as mergers like Chevron-Texaco. The narrow definition begins with the preferred definition, but does not count as a sale a transfer to a newly created firm, a transfer from a disappearing firm, nor sales at the initial time of production. Just over half of observations are for producing wells, and under half for non-producing wells.

Our broadest definition, shown in the light grey bars in Figure 1, includes *any* change in operator ID, even if the names are similar or it was part of a known merger. By this definition, the typical well experiences a sale every 13 years. Our narrowest definition of a sale begins with our preferred definition, but then excludes transfers to newly created firms, transfers from disappearing firms, and sales at the initial time of production.[6] By this measure, the typical well experiences a sale approximately every 24 years.

Thus by any of our three definitions, sales are frequent, ranging from 0.04 to 0.07 per year. Even by our narrowest definition, we observe more than 20,000 well sales in a typical year. Using our broadest definition, we observe nearly one million sales across our sample as a whole. In addition, sales are common even for non-producing wells, of relevance for policy questions related to well abandonment. The Appendix shows that it is true across a variety of well characteristics, such as the mix of oil versus gas production and the well location.

Moreover, this annual well-level average reflects the fact that many wells are sold, and that some wells are sold frequently. In Figure 2, we show a histogram of the count of well sales across all wells. For ease of interpretation, and to compare wells in our unbalanced panel on an apples-to-apples basis, we limit our sample to wells for which we observe production and ownership at ages one through twenty, over the period 1993 to 2023. For this sample of wells (N=56,589), we count the number of ownership transfers across these first two decades of the well's life.[7] Roughly 66% of wells experience at least one sale; that is, many wells are sold. 41% of wells are sold at least twice. And, wells being sold four or more times in their first two decades is not uncommon (10%).

## 4.2 Many wells have low production and low profitability

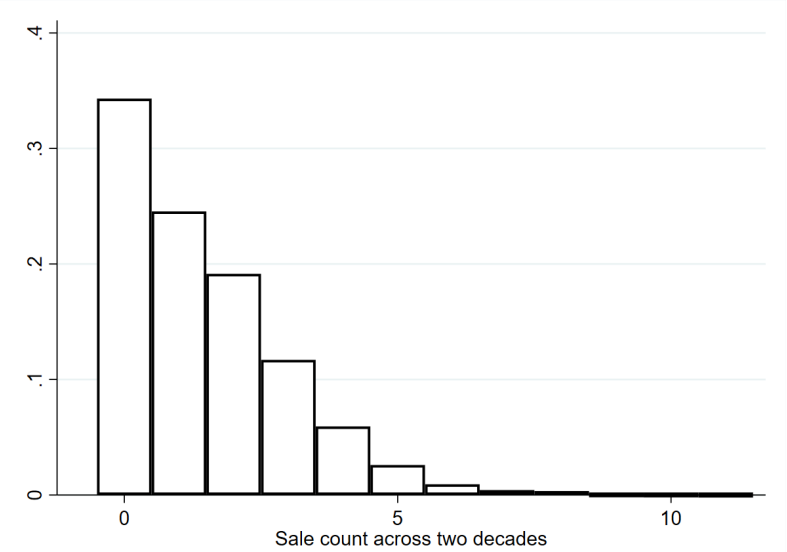
Having established that well sales are common, we next show that low-production and low-profitability wells are common. Much of the economics literature has focused on initial drilling, when production volumes are high. By contrast, much of the environmental literature has focused on abandoned wells, when production is zero. We show that an important stage of a well's life is when it is still operating but at a low volume and with low expected future profitability.

As illustrated in Table 1, the median oil well in our sample produces only 200 barrels of oil per year, and the median gas well only 4,000 mcf per year. The *mean* values are around an order of magnitude higher, showing the tremendous skew in production. Even conditioning

[6] One industry analyst told us that internal reorganizations from the initial drilling stage to the production stage can appear as changes in operator ID but do not involve true changes in ownership.

[7] The number of wells represented in this figure is only about 10 percent of our sample, because requiring that we observe two decades of a well's life implies that the well started producing before 2004. An alternative analysis, with a larger sample size, is included the Appendix and yields similar conclusions.

Figure 2: Some Wells Are Sold Frequently




Note: This graph shows the portion of wells that experience 0 versus 1 versus 2 (and so on) sales over the first 20 years of their life (N=56,589). The sample is limited to wells for each we observe production and ownership at ages 1 through 20, over the period 1993 to 2023. While roughly one third experience no sales and one quarter experience one sale, 20% experience two sales, and another 20% experience three or more sales.

on non-zero production volumes (i.e., ignoring shut-in wells), the median volumes are only 900 barrels of oil and 7,000 mcf of gas.

As a result, the median annual revenue is only $15,000, or $75,000 at producing wells; and notably, these revenues do not account for well costs. Average revenues are an order of magnitude higher. *Initial* revenue at the median well is also an order of magnitude higher; the average initial revenue is almost $3 million in the first year.

This dramatic difference in initial revenue versus revenue throughout the rest of the well's life is driven by the decline curve that a typical well follows. Consequently, expected future profitability is generally low: low-producing wells are likely to remain low-producing wells until they cease production. To illustrate, we calculate the continuation value of each well under plausible assumptions about decline curves, future oil and gas prices, and ongoing operations costs. Details on each assumption are provided in the Appendix.

The median well has only $8,000 to $52,000 in discounted expected future profits under various alternative assumptions. If we limit to only producing wells, the median continuation value is $160,000. If we assume that future oil and gas prices will be high, the median continuation value at producing wells is $300,000 – still quite low relative to the average revenue, which is increased by high-production wells and by large initial revenues.

Table 1: Many wells have low production and low profitability

| | N | Median | Mean |
|---|---|---|---|
| Oil production (barrels), oil-only wells | 2,855,040 | 240 | 3,100 |
| Oil production, mixed wells | 2,869,860 | 150 | 5,000 |
| Gas production (mcf), gas-only wells | 3,202,777 | 3,700 | 47,000 |
| Gas production, mixed wells | 2,869,860 | 3,700 | 36,000 |
| Oil production, producing wells only | 3,814,005 | 850 | 6,100 |
| Gas production, producing wells only | 4,955,052 | 7,000 | 51,000 |
| Revenue (dollars), all wells | 9,915,807 | 15,000 | 310,000 |
| Revenue, producing wells | 6,646,478 | 75,000 | 470,000 |
| Initial revenue | 5,113,327 | 890,000 | 2,700,000 |
| Continuation value (dollars), all wells | 10,101,587 | 25,000 | 820,000 |
| Continuation value, 2018-2021 | 2,230,909 | 8,400 | 840,000 |
| Continuation value, alternative commodity price assumptions | 10,101,587 | 17,000 | 740,000 |
| Continuation value, alternative cost assumptions 1 | 10,101,587 | 14,000 | 940,000 |
| Continuation value, alternative cost assumptions 2 | 10,101,587 | 28,000 | 690,000 |
| Continuation value, alternative decline curve | 10,101,587 | 23,000 | 840,000 |
| Continuation value, producing wells | 6,771,620 | 160,000 | 1,200,000 |
| Continuation value, high oil and gas prices | 10,101,590 | 52,000 | 1,500,000 |
| Continuation value, high oil and gas prices, producing wells | 6,771,623 | 300,000 | 2,200,000 |

Note: A unit of observation is a well-year, covering four states over the period 1999-2023. Wells known to be plugged are not included. Oil and gas production are quantities reported to state agencies; revenue is calculated using prices from EIA; and various estimates of continuation value are calculated using assumptions on future well decline, future commodity prices, and future operating costs.

To summarize, a significant portion of wells are operating at low volumes, with low current revenue and with low future expected profitability. Understanding the behavior of these wells is important for understanding the entire life cycle of a well. In addition, projecting out a decade, it is likely that we will continue to have a large stock of low-volume and non-producing wells at risk of abandonment and orphaning, a point to which we return below.

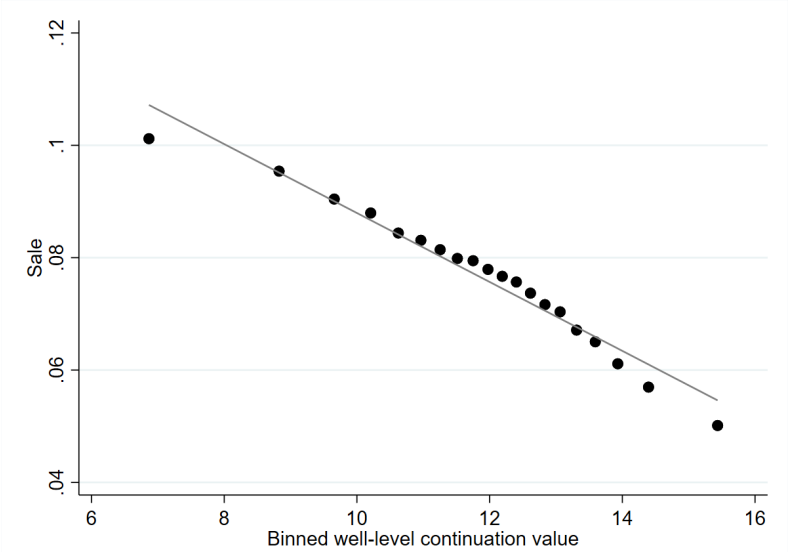
## 4.3 Wells are more likely to be sold as their value declines

Both industry reports and environmental groups have noted that well sales are common for low-production wells. In industry reports, this pattern is described as part of the "food chain" of oil and gas production. Before exploring the potential reasons for sales of low-producing wells, we first document that the likelihood of a sale does indeed increase as well production declines.

Our descriptive regression takes the form

$$s_t = \beta_1 r_t + X_t \Theta + \varepsilon_t \tag{1}$$

Figure 3: Low-value wells are sold more often




Note: This graph shows sale frequencies against expected future profits. The sample consists of 3.4 million well-by-year observations, covering 1993 to 2023 (unbalanced across states, depending on data availability). The binned continuation value variable is the residual continuation value after removing region effects, well type (oil versus gas versus mixed) effects, and a time trend. See text for details. A regression version is shown in Table 2, and robustness checks are provided in the Appendix.

where $s_t$ is a count of the number of sales the well experiences in a year (typically zero or one, but occasionally greater than one); $r_t$ is some measure of well size or profitability; and $X_t$ is a suite of controls. The unit of observation is a well in a year, and we focus on the 1993-2023 panel. Standard errors are two-way clustered by well and by year.

To illustrate this regression, Figure 3 shows the correlation between sale frequency and continuation value (the latter in logs) after accounting for region effects, type effects, and a linear time trend. Sale likelihood declines with continuation value: low-value wells are sold more often, and high-value wells are sold less often. The relationship is remarkably stable across the range of continuation values that we see in our 3.4 million observations.

In both Figure 3 and our regression analysis, the measure of well size $r_t$ is the well's continuation value, which depends on well production, commodity prices, and operating costs. In the Appendix, we show results under alternative assumptions about operating costs or future revenues. Annual well production levels are *close* to exogenous, as they are determined largely by geology and the decline rate inherent at each well. Production levels could be endogenous to well sales if different owners have different rates of well restimulation and/or different thresholds for shutting in wells. Similarly, revenue is close to exogenous, but with the added potential endogeneity of prices responding to production shocks across

wells. Given the large number of wells and operators, any individual well is unable to impact prices – but prices may respond to aggregate shocks common to many wells (as indeed, they did when the fracking revolution took hold).

To address these potential sources of bias, the Appendix shows results using annual revenue or the well's age as the independent variable of interest. Well production declines exogenously with well age, as a function of geologic pressure. Operators have no control over well age, and after for controlling for sample-wide time effects, well age is uncorrelated with other potential determinants of well sales. We also show instrumental variables specifications, in which age is an instrument for continuation value.

In both Figure 3 and our regression analysis, our control variables include region effects (e.g., Colorado has four regions; Texas has five), well type effects (gas-only versus oil-only versus mixed), and a linear time trend. Ideally, our controls would be very fine-grained: well effects to control for heterogeneity in time-invariant well quality, and year effects to account for broad market trends. However this leads to an age-period-cohort problem. Consider the specifications where our right-hand side measure of interest is well age: we seek to determine if wells are sold more often as they age and exogenously transition to low production. However, age is an exact linear combination of well effects and year effects. Using production or continuation value as the dependent variable partly alleviates this problem but also partly masks it: we still want to rely for identification on exogenous declines in well productivity as wells age, which fundamentally has an age-period-cohort problem, even when we do not have an exact linear combination of right-hand side variables.

To address the age-period-cohort problem, we explore a variety of specifications with alternative controls. The base specification uses region effects, to account for regional differences in geology; well type effects, to account for differential profitability across oil, gas, and mixed wells; and a time trend, to account for broad national changes in the oil and gas market. Remaining variation thus comes from idiosyncratic initial well quality within a region and a well type; from idiosyncratic variation in well decline rates, again within a region and well type; and from regional price shocks that deviate from national trends. One alternative specification uses type effects, region effects, and year effects. This approach relies most on regional price shocks that deviate from national year-specific shocks; it also continues to rely on idiosyncratic well characteristics within a type and a region. Another alternative specification instead controls for individual well effects and a linear trend; this specification relies more heavily on regional price shocks that deviate from a national trend, as it controls for time-invariant well heterogeneity. The final alternative specification controls for region-by-year and type-by-year effects.

Table 2 shows the estimated $\beta_1$ coefficient from Equation 1. Column 1 shows the base

Table 2: Low-value wells are sold more often

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Expected future profits (log) | -0.006*** | -0.005*** | -0.004*** | -0.011*** |
| | (0.001) | (0.001) | (0.001) | (0.002) |
| Observations | 7,197,388 | 7,197,388 | 7,197,386 | 7,165,804 |
| $R^2$ | 0.02 | 0.03 | 0.06 | 0.10 |
| Controls | Well type | Well type | Well by year | Well effect |
| | Region type | Region type | Region by year | |
| | Time trend | Year effect | | Time trend |

Note: The unit of observation is a well in a year. The dependent variable is count of ownership transfers (typically 0 or 1, occasionally greater than 1). The independent variable of interest is expected continuation value, logged. All columns include controls; see text for details. Alternative specifications and variable definitions given in the Appendix. Standard errors are two-way clustered by year and by well.

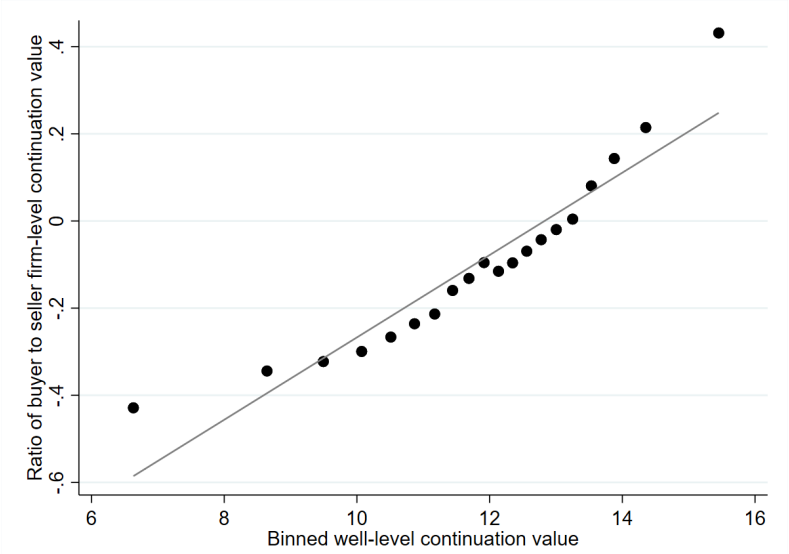
specification, with region effects, well type effects, and a linear time trend. Columns 2 through 4 show alternative sets of controls, recognizing that because of the age-period-cohort problem and because the primary identifying variation in prices is a national time series, there is not an obvious ex-ante preferred set of fixed effects. Across all four specifications, the coefficient is fairly stable, ranging from -0.006 to -0.011: a well with a continuation value decline of 10 log points is 0.06 to 0.11 percentage points more likely to experience a sale in a given year, relative to a mean sale rate of 7.5 percent.

In the Appendix, we consider a suite of alternative specifications. These include alternative right-hand side variables (e.g., revenue or age); alternative assumptions on continuation value (e.g., alternative decline curves to predict future consumption, or alternative assumptions on future prices); alternative sub-samples (e.g., recent years only, or specific states); and additional controls (e.g., initial revenue, or the interactions of fixed effects). The results are remarkably stable across these specifications.

## 4.4 Low-value wells are sold to low-value firms

We next ask: when wells are sold, who buys them? Environmental advocates worry that low-value wells, at risk of orphaning, are sold to low-capitalization firms, i.e., the firms of most concern for the judgment-proof problem. We first construct variables at the firm-by-state-by-year level: the aggregate continuation value of all the wells owned by the firm, as a measure of firm profitability. Because firm identification numbers are not harmonized across states, we are limited to a measure of firm profitability within each state. We then take the

Figure 4: Low-value wells are sold to low-value firms




Note: This graph shows the ratio of buyer to seller continuation value (logged) against the future profitability of a sold well (binned). The sample consists of roughly 340,000 well-by-year observations, covering 1993 to 2023 (unbalanced across states, depending on data availability). The binned continuation value variable is the residual continuation value after removing region effects, well type (oil versus gas versus mixed) effects, and a time trend. See text for details. A regression version is shown in Table 3, and robustness checks are in the Appendix.

log of the ratio of buyer to seller size. A ratio greater than 1 (i.e., a log ratio greater than 0) indicates that the buyer is larger than the seller. For the sample of wells that are sold in any year, we then examine the descriptive relationship between this buyer-seller ratio and the profitability of transferred wells.

We begin by plotting, in Figure 4, the log ratio of buyer to seller size against the log continuation value of the well that was sold. We again control for region effects, type effects, and a linear time trend. Figure 4 shows a clear, strong relationship: high-value wells are involved in sales where the buyer is relatively larger; low-value wells are involved in sales where the buyer is relatively smaller. This is consistent with the environmental advocates' expressed worry: that low-value wells are sold to firms at risk of bankruptcy. The line roughly crosses a ratio of 0 at the 75th percentile well-level continuation value. That is, top quartile are involved in sales where the buyer is larger than the seller; and wells below the top quartile are involved in sales where the buyer is smaller than the seller.

We then formalize our analysis of this relationship with regression specifications similar

to those used in the previous section:

$$f_t = \beta_1 r_t + X_t \Theta + \varepsilon_t \tag{2}$$

where $f_t$ is the log ratio of buyer to seller continuation value; $r_t$ is well-level continuation value; and $X_t$ is a suite of controls. The unit of observation is a well in a year, conditional on the well experiencing a sale in that year, and we again focus on the 1993-2023 panel. As before, mindful of the age-period-cohort problem, we show four alternative specifications with differing combinations of well and time controls. We are no longer able to two-way cluster by well and year – having restricted our sample to wells that are sold, combined with the high dimensionality of fixed effects we use in some specifications, the resulting covariance matrix is highly singular. As such, we instead two-way cluster by region-well type and by year in all specifications.

Table 3 shows our results. Across all four columns, we see that the ratio of buyer to seller size is positively correlated with the continuation value of sold wells. The magnitude differs across the set of controls we include. In the baseline specification, with region effects, type effects, and a time trend, the coefficient on log continuation value is 0.095, statistically significant at the 1 percent level. To understand the magnitude, suppose a selling firm offloads two wells, and that one of the wells is 10 log points smaller than the other well. The smaller well would be predicted to go to a firm that is 0.95 log points smaller than the firm buying the larger well.

When controlling for year effects, or region-by-year and type-by-year effects, the magnitude is smaller. However, controlling for well effects, the magnitude is substantially larger. Note that when controlling for well effects, the regression is identified from wells with repeat sales; this specification reduces the sample size and changes the interpretation, as wells with repeat sales may be of differing quality than wells with only a single sale.

Results in the Appendix again show the robustness of this positive relationship to a variety of alternative variable construction procedures, sub-samples, and controls.

## 4.5 Some long-run outcomes vary by whether a well is sold

To understand whether sales are consistent with firm-level specialization, with liability shedding, or both, we next regress a series of long-run outcomes on an indicator for whether wells were previously sold. The long-run outcomes of interest are: whether or not a well is producing, the quantity the well produces, and whether the well has been plugged. In an ideal experiment, we would have randomly-assigned sales at, for instance, age ten, and we would examine whether wells then behave differently at age twenty.

Table 3: Low-value wells are sold to low-value firms

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Expected future profits (log) | 0.095*** | 0.050*** | 0.033*** | 0.282*** |
| | (0.016) | (0.014) | (0.011) | (0.048) |
| Observations | 506,590 | 506,588 | 506,576 | 353,587 |
| $R^2$ | 0.04 | 0.13 | 0.23 | 0.30 |
| Controls | Well type | Well type | Well by year | Well effect |
| | Region type | Region type | Region by year | |
| | Time trend | Year effect | | Time trend |

Note: The unit of observation is a sold well in a year. The dependent variable is ratio of buyer to seller continuation value, logged. The independent variable of interest is expected continuation value, logged. All columns include controls; see text for details. Alternative specifications and variable definitions given in the Appendix. Standard errors are two-way clustered by region-well type and by year.

Well sales are, of course, not exogenously determined or randomly assigned. Instead, they are the result of both buyer and seller strategic priorities and cost structures. To come closer to a regression interpretation of how wells would have evolved in counterfactuals with versus without sales, we condition on several observable well features – all indicators of well quality – that are likely to be correlated with the decision to transfer an asset. Specifically, we condition on the well's initial production, a measure of its overall size. We condition on production in the period right before the sales of interest, a measure indicator of how profitability has evolved since initial drilling. And we condition on the well's decline rate, another measure of how its profitability has evolved as the oil or gas resource has been depleted, as well as how it will continue to evolve in the future. We also control for the interaction of region, well type, and year indicators, to control for market-wide changes in oil and gas profitability, which is a function of changing commodity prices, extraction technologies, environmental regulations, and so forth. Thus the thought experiment underlying the regression analysis is to compare two wells in the same region extracting the same commodity and on similar production paths: one sold, and one not sold, to see how production and environmental compliance evolve in the long run.

This regression does not solve the underlying problem of selection into treatment status, but it does give a descriptive indication of whether wells that are sold eventually end up producing more or less, and whether they ultimately are more or less likely to be closed in an environmentally responsible way.

Because we are most interested in outcomes for aging wells with lower production - which represent the majority of wells in out sample – we focus on outcomes at age 21 for wells

Table 4: Some long-run outcomes vary by whether a well is sold

| | Indicator, Producing | Production, If Non-Zero | Production (Relative) | Plugged Status | Plugged, If Non-Producing |
|---|---|---|---|---|---|
| Ever sold, age 16-20 | 0.022 | -0.004 | -0.005 | -0.029 | -0.090*** |
| | (0.018) | (0.005) | (0.005) | (0.018) | (0.032) |
| Initial production | 0.000*** | -0.000*** | -0.000*** | 0.000 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| Decline rate | -1.018*** | -0.208*** | -0.166*** | 0.154*** | -0.009 |
| | (0.097) | (0.023) | (0.016) | (0.033) | (0.052) |
| Pre-sale production | 0.446*** | 0.504*** | 0.465*** | -0.119*** | -0.065 |
| | (0.059) | (0.029) | (0.026) | (0.042) | (0.060) |
| Observations | 67,693 | 47,467 | 67,693 | 46,370 | 14,177 |
| $R^2$ | 0.22 | 0.44 | 0.42 | 0.07 | 0.05 |

Note: The unit of observation is a well at age 21. The dependent variable is listed at the top of each column; see text for details. For instance, relative production is production at age 21, scaled by production at age 1. The right-hand side variable of interest is an indicator for whether any sale occurred at age 16 to 20, i.e. in the five years running up to age 21. Note oil and gas production have been combined using a time-invariant ratio of 70 barrels to 4 mcf, roughly reflecting typical oil versus gas prices. Initial production is production at age 1, and pre-sale production is relative production at age 14. All columns also control for region by type by year indicators. Standard errors are clustered by the interaction of owner at age 16 and owner at age 21. Robustness checks are shown in the Appendix.

transferred at intermediate ages (age 16-20). Note that the regression is a cross-section of wells, since by definition, wells only experience age 21 one time. However the various observations are from different years, as wells reach age 21 at different times depending on their initial production date. The year effects are thus controlling for both differences in market characteristics at initial spud date and differences in market characteristics at age 21.

Table 4 displays the results. The first column shows that wells that are sold are more likely to be producing at age 21. This is consistent with industry claims that some operators specialize in operating older wells; for instance, these operators may be able to restimulate the old well. However, in the second column, we see that conditional on producing, the quantity extracted is indistinguishable at wells that are versus are not sold. In the third column, we see that when combining these extensive and intensive margin effects into a single measure of total production, well production does not depend on whether the well was sold. That is, the extensive margin effect is too small to show up in the measure of overall production.

So overall, sold wells do not appear to go to companies that are able to extract a bit more oil or gas, in contrast to industry claims that buyers of old wells have a particular advantage in extraction at these types of wells. Note it could nonetheless be the case that

had these same wells not been sold, they would have experienced a lower level of production – we cannot rule out this explanation, since we cannot rule out selection into a sale.

In the fourth column, we see that sold wells are less likely to be plugged at age 21. However, this effect could result in part from sold wells being more likely to produce, as in column 1. Thus in the fifth column, we limit the sample to non-producing wells – we again see that sold wells are less likely to be plugged. This result is consistent with either intentional liability shedding or with buyers of old wells being unable to afford proper plugging procedures. In either case, the column five results are consistent with the environmental advocates' worry that transfers are associated with poor environmental outcomes.

The Appendix shows a suite of robustness checks. We look at other sale definitions (broader and narrow); outcomes at a longer time horizon; sales at alternative ages; alternative sets of controls; and each state individually. The positive coefficient on sales in the producing indicator column is fairly robust, although sometimes the magnitude is smaller and statistical significance is lost. Both production conditional on producing and overall total production generally show very small effects that are not statistically different from zero, although some specifications show positive and some specifications show negative coefficients. The negative effect in the fifth column – the result that is consistent with sales predicting poor environmental outcomes – is quite stable across alternative specifications. However we note that this result is largely driven by our California sample: we have limited observations in Colorado and Pennsylvania with a full 21 years of data, and we do not observe plugged status in Texas.

# 5 Model of Well Transfers

In this section, we build a model of well transfers that is consistent with the empirical patterns observed in the data.

*Model Set-Up:*

The per-period profit from operator $j$ producing from well $i$ is given by:

$$\pi_{ijt} = p_t q_{it} - c_j(q_{it})$$

where $p_t$ is the price for oil/gas, $q_{it}$ is the quantity of oil/gas produced in period $t$, and $c_j(\cdot)$ is operator $j$'s cost function.

Table 5: Heterogeneity in long-run outcomes: firm size

| | Indicator, Producing | Production, If Non-Zero | Production (Relative) | Plugged Status | Plugged, If Non-Producing |
|---|---|---|---|---|---|
| Sold, age 16-20, to much smaller firm | 0.055*** | -0.011 | -0.008 | -0.067*** | -0.238*** |
| | (0.018) | (0.007) | (0.006) | (0.023) | (0.047) |
| Sold, age 16-20, to somewhat smaller firm | 0.081** | 0.001 | 0.003 | -0.140** | -0.268*** |
| | (0.038) | (0.008) | (0.006) | (0.062) | (0.090) |
| Sold, age 16-20, to somewhat larger firm | 0.012 | -0.008 | -0.013 | -0.016 | -0.012 |
| | (0.041) | (0.009) | (0.009) | (0.051) | (0.083) |
| Sold, age 16-20, to much larger firm | -0.012 | 0.004 | -0.003 | -0.006 | -0.021 |
| | (0.028) | (0.007) | (0.006) | (0.039) | (0.052) |
| Sold, age 16-20, firm size missing | -0.229*** | 0.031 | -0.009 | -0.106 | -0.177* |
| | (0.045) | (0.032) | (0.011) | (0.070) | (0.095) |
| Initial production | 0.000*** | -0.000*** | -0.000*** | 0.000 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| Decline rate | -0.923*** | -0.208*** | -0.145*** | 0.289*** | 0.051 |
| | (0.124) | (0.023) | (0.021) | (0.055) | (0.065) |
| Pre-sale production | 0.534*** | 0.503*** | 0.468*** | -0.290*** | -0.413*** |
| | (0.086) | (0.029) | (0.025) | (0.101) | (0.132) |
| Observations | 72,862 | 47,473 | 72,862 | 51,554 | 19,333 |
| $R^2$ | 0.28 | 0.44 | 0.43 | 0.17 | 0.11 |

Note: This table is identical to Table 4, but the "ever sold at age 16-20" is separated into five indicators, based on the size of the buyer relative to the seller. There are 100-200 transactions within each buyer/seller relative size category. There are only a small number for which we do not have buyer/seller size calculated.

Assume that oil/gas production follows an exponential decline curve, such that $q_{it}$ is a deterministic function of time since the well was drilled $(t - t_{0i})$ and some well-specific decay parameter $(\eta_i)$:

$$q_{it} = \eta_i \exp\left(-\eta_i (t - t_{0i})\right)$$

We parameterize the operator cost function to allow matching between well production levels and operator specialization:

$$c_j(q_{it}) = \alpha_{0j} + \alpha_{1j} q_{it} + \alpha_{2j} (q_{it} - q_j)^2$$

where $q_j$ is the production level that operator $j$ specializes in.

In each period, there is some probability of environmental incident, $\lambda_{ij}$, which depends on both the well and the operator. If an environmental incident occurs, the operator must pay $\omega_i$ in cleanup costs before continuing to produce. Therefore, the expected cost of an environmental incident in each period is $\lambda_{ij}\omega_i$.

We assume that, for some portion of a well's lifetime, producing from the well is privately

profitable despite the risk of environmental incident:

$$\exists t \text{ s.t. } \pi_{ijt} - \lambda_{ij}\omega_i \geq 0$$

Each well also has some end-of-life cleanup costs $\chi_i$. After production occurs and environmental incidents are realized (with the associated cleanup costs) in each period, the operator evaluates whether to plug ($P_{ijt} = 1$) or leave operational ($P_{ijt} = 0$) each well $i$:

$$\max_{P_{ijt} \in \{0,1\}} -\chi_i \cdot P_{ijt} + \beta_j \mathrm{E}[V_{ij,t+1} | P_{ijt} = 0] \cdot (1 - P_{ijt})$$

where $\mathrm{E}[V_{ij,t+1}]$ represents the expected continuation value of the well and $\beta_j$ represents the firm's discount factor.

Define $T_{ij}$ as the first period such $P_{ijt} = 1$, i.e., the first period such that it is privately profitable to pay plugging costs rather than continue to operate the well. At $T_{ij}$, the following expression holds:

$$-\chi_i = \max\{-\chi_i, \beta_j \mathrm{E}[V_{ij,t+1}]\}$$

In order for some finite $T_{ij}$ to exist, we assume that $p_t$ is finite and $\frac{\beta_j(\alpha_{0j} + \lambda_{ij}\omega_i)}{1-\beta_j} > \chi_i$, i.e., indefinitely incurring fixed operating costs and the risk of environmental incident is less profitable than paying end-of-life well cleanup costs. In the baseline model, each $P_{ijt}$ is deterministic (as is $T_{ij}$), since environmental incidents are realized before plugging decisions occur and we assume that firms must pay cleanup costs after an environmental incident regardless of whether they decide to plug the well in that period.

Therefore, the expected remaining value of well $i$ owned by firm $j$ at time $t$ is given by:

$$\mathrm{E}[V_{ijt}] = \max_{P_{ijt} \in \{0,1\}} \pi_{ijt} - \lambda_{ij}\omega_i - \chi_i \cdot P_{ijt} + \beta_j \mathrm{E}[V_{ij,t+1} | P_{ijt} = 0] \cdot (1 - P_{ijt})$$

We can also define the expected remaining value of an operator's portfolio of wells as follows:

$$\mathrm{E}[V_{jt}] = \sum_{i \in I_{jt}} \mathrm{E}[V_{ijt}]$$

where $I_{jt}$ represents the set of wells owned by operator $j$ in period $t$. Note that the expected remaining private value is equivalent to the expected remaining social value in this baseline model whenever $\beta_j = \beta^*$, where $\beta^*$ is the social planner's discount factor.

*Cost of Failing to Plug:*

An environmental incident, without clean-up, produces social damages equal to $D_i$. With clean-up, damages are 0. We assume that $D_i > \omega_i$; that is, it is always socially beneficial to clean up following an environmental incident, even if not necessarily privately profitable.

We assume that the expected social cost of indefinitely leaving a well unplugged always exceeds the firm's cost of plugging and abandoning the well. That is, we assume:

$$\frac{\beta^*(\lambda_{ij} D_i)}{1-\beta^*} > \frac{\beta^*(\lambda_{ij}\omega_i)}{1-\beta^*} > \chi_i$$

The term on the left represents the expected discounted present value of damages from environmental incidents when the well is left unplugged indefinitely and incidents are not cleaned up.[8] The middle term represents the expected discounted present value of environmental incident cleanup costs when the well is left unplugged indefinitely. The term on the right represents cost of plugging the well today.[9]

Finally, note that the cost of well plugging is generally larger when the regulator must incur those costs ($X_i$) instead of the firm ($\chi_i$), as the firm has greater knowledge of well and site characteristics. The regulator must also expend costly public resources to pay for plugging.[10] For this reason, regulators will not always plug wells that have been left unplugged by their (former) operators, even if environmental damages ensue.

*Limited Liability:*

Next we introduce limited liability. After observing whether an environmental incident has occurred but before paying for any environmental incident cleanup costs or plugging its wells, an operator has the option to declare bankruptcy and abandon all of its wells ($B_{jt} = 1$)

[8]For wells with no solvent operator of record (i.e., orphan wells), we assume that the risk of environmental incident $\lambda_{ij}$ is influenced by the well's most recent operator $j$.

[9]Note that this inequality is equivalent to assuming that it is socially efficient to plug the well today rather than incurring an additional period of potential environmental incident cleanup costs and plugging tomorrow. Moreover, if the social planner's discount factor is equal to (or not too much greater than) the firm's discount factor, we also have:

$$\frac{\beta_j(\alpha_{0i} + \lambda_{ij}\omega_i)}{1-\beta_j} > \chi_i$$

If we further assume that $p_t$ is finite, then we guarantee that $T_{ij}$ is finite, as noted above.

[10]More generally, this assumption may reflect that end-of-life cleanup costs may be lowered when the firm internalizes those costs and therefore faces an "incentive to take care." We do not explicitly model firm effort to lower cleanup costs, however.

instead of continuing to operate ($B_{jt} = 0$).

In each period, the operator evaluates:

$$\max_{B_{jt}\in\{0,1\}} 0 \cdot B_{jt} + \{-\sum_{i\in I_j} A_{ijt} \cdot \omega_i - \sum_{i\in I_j} P_{ijt} \cdot \chi_i + \beta_j \mathrm{E}[\tilde{V}_{j,t+1}|\mathbf{P_{jt}}, B_{jt} = 0]\} \cdot (1 - B_{jt})$$

where $\mathrm{E}[\tilde{V}_{j,t+1}] = \sum_{i\in I_{jt}} \mathrm{E}[\tilde{V}_{ij,t+1}]$ represents the continuation value of the operator's portfolio of wells given the perpetual option to declare bankruptcy. Because firms may choose not to execute this option, $\mathrm{E}[\tilde{V}_{j,t+1}] \geq \mathrm{E}[V_{j,t+1}]$. We assume that the portfolio scrap value from declaring bankruptcy is equal to 0. Define $A_{ijt}$ as an indicator variable for whether an environmental incident has occurred at well $i$ in period $t$, i.e., $\mathrm{Prob}(A_{ijt} = 1) = \lambda_{ij}$. Lastly, $\mathbf{P_{jt}}$ is a vector representing plugging decisions at all individual wells in the operator's portfolio.

Here it is useful to distinguish between two reasons why an operator might choose to declare bankruptcy, one stochastic and one deterministic. In the first case, which we will call $B^s_{jt} \in \{0, 1\}$, the operator faces a costly environmental incident and declares bankruptcy to avoid paying cleanup costs in the current period (as well as eventual end-of-life costs). In the second case, which we will call $B^d_{jt} \in \{0, 1\}$, the operator plans to declare bankruptcy in order to avoid paying known end-of-life cleanup costs. The overall bankruptcy decision in each period combines these two potential motivations: $B_{jt} = \max\{B^s_{jt}, B^d_{jt}\}$.

Define $\tilde{T}_j$ as the first period such that $B_{jt} = 1$, i.e., the first period in which it is privately profitable to abandon an entire portfolio of wells through bankruptcy. At $\tilde{T}_j$, the following expression holds:

$$0 = \max\{0, -\sum_{i\in I_j} A_{ijt} \cdot \omega_i - \sum_{i\in I_j} P_{ij\tilde{T}_j} \cdot \chi_i + \beta_j \mathrm{E}[\tilde{V}_{j,\tilde{T}_j+1}|\mathbf{P_{jT_j}}, B_{jT_j} = 0]\}$$

$\tilde{T}_j$ may be reached due to either unanticipated bankruptcy ($B^s_{jt} = 1$) or anticipated bankruptcy ($B^d_{jt} = 1$). Let $\tilde{T}^d_j$ represent the period at which the operator anticipates declaring bankruptcy in order to avoid paying end-of-life costs across its portfolio. Let $\tilde{T}^s_j$ represent an "early" bankruptcy due to unexpected environmental incident(s). By construction, $\tilde{T}^s_j$ is stochastic, while $\tilde{T}^d_j$ is deterministic. The period in which the operator declares bankruptcy (if any) combines these two decisions and is therefore stochastic: $\tilde{T}_j = \min\{\tilde{T}^s_j, \tilde{T}^d_j\}$.

Note that $\tilde{T}_j^s \leq \tilde{T}_j^d$ by construction. However, $\tilde{T}_j^s$ and $\tilde{T}_j^d$ may be infinite if an operator never finds it optimal to declare bankruptcy – for example, because the operator continues to drill or acquire productive wells. Well operators form expectations about $\tilde{T}_j$ given their knowledge about production decline curves, oil and gas prices, production costs, and the expected cost of environmental incidents across all wells in their portfolio.

**Proposition 1:** An operator's willingness to pay plugging and environmental incident cleanup costs is increasing in the continuation value of its well portfolio, $\mathrm{E}[\tilde{V}_{j,t+1}]$.[11]

Consider the extreme case where the operator owns only one well. In this case, the operator will choose to declare bankruptcy rather than incur end-of-life cleanup costs for the well. Recall that the firm's optimal plugging time for a well, $T_{ij}$, is defined as the first period such that $-\chi_i > \beta_j \mathrm{E}[V_{ij,T_{ij}+1}]$. However, receiving a scrap value of 0 is more profitable than paying plugging costs of $\chi_i$, so the operator of a single well will declare bankruptcy at (or before) $T_{ij}$.

Likewise, if the operator owns a portfolio of wells but $T_{ij} = \tau$, a constant, $\forall i \in I_{jt}$, then the operator will also find it optimal to declare bankruptcy rather than pay end-of-life cleanup costs, which are all due in the same period. This model prediction helps to explain real-world policymaker concerns about operators with large portfolios of low-producing (and hence low continuation value) wells.

More generally, imagine that an operator's portfolio includes one well $i$ with end-of-life at $T_{ij}$, and all other wells in the portfolio have end-of-life at $T_{i'j} \neq T_{ij}$ for $i' \neq i$. The operator is willing to pay end-of-life cleanup costs for well $i$ at $T_{ij}$ only when $0 < -\sum_{\iota \in I_{jT_{ij}}} A_{\iota j T_{ij}} \cdot \omega_\iota - \chi_i + \beta_j \mathrm{E}[V_{-i,j,T_{ij}+1}]$. This condition requires that the continuation value of the rest of the well portfolio is sufficiently large to justify paying end-of-life costs for well $i$.

The importance of portfolio continuation value in operators' willingness to pay end-of-life cleanup costs has particular salience in view of the energy transition. If and when the continuation values of oil and gas portfolios decline throughout the industry, fewer operators will be willing to incur end-of-life costs rather than simply declaring bankruptcy.

[11] Our emphasis on the importance of portfolio continuation value in operator willingness to pay end-of-life or environmental incident cleanup costs recalls the role of "reputation" in the model developed by Gerard (2000) for explaining why firms may decide to reclaim mining operations even when subject to limited liability and incomplete bonding requirements.

The expected remaining value of a well under the limited liability regime is given by:

$$\begin{aligned}\mathrm{E}[\tilde{V}_{ijt}] = \pi_{ijt} - \mathrm{E}[A_{ijt} \cdot \omega_i | B_{jt} = 0] \cdot \mathrm{Prob}(B_{jt} = 0) - \chi_i \cdot P_{ijt} \cdot \mathrm{Prob}(B_{jt} = 0) \\ + \beta_j \mathrm{E}[\tilde{V}_{ij,t+1} | B_{jt} = 0, P_{ijt} = 0] \cdot (1 - P_{ijt}) \cdot \mathrm{Prob}(B_{jt} = 0)\end{aligned}$$

Note that $P_{ijt}$ is defined here analogously to the previous section: we assume that firms must pay cleanup costs after an environmental incident regardless of whether they decide to plug the well in that period – only bankruptcy allows them to avoid paying cleanup costs.

By providing firms with an option that they can choose to exercise if continuation costs (end-of-life and/or environmental cleanup) are higher than the discounted continuation value, limited liability weakly increases private profits across the entire portfolio (though not necessarily for each well individually). However, the expected value of the well from the perspective of a welfare-maximizing social planner's has not changed.

*Transfers:*

Now let's introduce the possibility for transfers. At the start of each period, before production occurs, environmental incidents are realized, and any decisions about the continued operation of the well are made, operators can transfer wells to other operators to maximize the (private) expected value of each well. We assume no transaction costs associated with transfers in this model.

Given this option to transfer, the expected private value of well $i$ is now given by:

$$\begin{aligned}\mathrm{E}[\hat{V}_{it}] = \max_{j \in J_t} \{\pi_{ijt} - \mathrm{E}[A_{ijt} \cdot \omega_i | B_{jt} = 0] \cdot \mathrm{Prob}(B_{jt} = 0) - \chi_i \cdot P_{ijt} \cdot \mathrm{Prob}(B_{jt} = 0) \\ + \beta_j \mathrm{E}[\hat{V}_{i,t+1} | B_{jt} = 0, P_{ijt} = 0] \cdot (1 - P_{ijt}) \cdot \mathrm{Prob}(B_{jt} = 0)\}\end{aligned}$$

Here $\mathrm{E}[\hat{V}_{i,t+1}]$ represents the (private) continuation value of the well given this option to transfer wells between operators. Because transfer decisions are made at the very start of each period, note that the expected value of a well in that period does not depend on the identity of the previous operator.

To understand motivations for well transfers, we will evaluate the difference in expected well value under operators $j$ and $j'$ in two scenarios. First, hold fixed the probability of "early" bankruptcy in each period ($\mathrm{Prob}(B^s_{jt} = 1) = \mathrm{Prob}(B^1_{j't} = 1)$) and the timing of a

potential planned bankruptcy ($\tilde{T}_j^d = \tilde{T}_{j'}^d$). In this case, the difference in expected well value across operators arises from differences in production cost parameters $\alpha_{0j}$, $\alpha_{1j}$, $\alpha_{2j}$, and $q_j$; differences in the probability of environmental incident $\lambda_{ij}$; and differences in the discount factor $\beta_j$, which we interpret as reflecting differences in the cost of capital.[12]

Second, hold fixed these primitives across operators and instead allow the probability of early bankruptcy and the timing of a planned bankruptcy to vary across operators (e.g., due to differences in portfolio composition). In this case, the difference in expected well value arises from differences in operators' ability to discount continuation costs (end-of-life and/or environmental cleanup costs) through bankruptcy.

**Proposition 2:** Well transfers between operators may occur due to productive reallocation (differences in $\alpha_{0j}$, $\alpha_{1j}$, $\alpha_{2j}$, $q_j$, $\lambda_{ij}$, and $\beta_j$) or liability shielding (differences in $\tilde{T}_j^d$ and $\text{Prob}(B_{jt}^s = 1)$).

To further examine the consequences of a limited liability regime combined with the ability to transfer wells across oeprators, note that the equilibrium price for a well must lie somewhere between the value of the well under its previous owner and the value of the well under its new owner. That is:

$$P_{j \to j'} = \text{E}[\tilde{V}_{ijt}] + \gamma(\text{E}[\tilde{V}_{ij't}] - \text{E}[\tilde{V}_{ijt}])$$

where $\gamma \in [0, 1]$ represents a bargaining parameter that governs how surplus is divided between the buyer and the seller.

Consider a case in which well $i$ is sold by operator $j$ to operator $j'$, who later sells the well to operator $j''$. Assume that operators $j$ and $j'$ have no chance of declaring bankruptcy (i.e., they are well capitalized with high portfolio continuation values). Then the total expected surplus captured by operator $j'$ is given by:

$$\begin{aligned}
&(1-\gamma)(\text{E}[\tilde{V}_{ij't}] - \text{E}[\tilde{V}_{ijt}]) + \beta_{j'}\gamma(\text{E}[\tilde{V}_{ij'',t+1}] - \text{E}[\tilde{V}_{ij',t+1}]) \\
&= (1-\gamma)((\pi_{ij't} - \pi_{ijt}) - (\lambda_{ij'}\omega - \lambda_{ij}\omega_i)) + \beta_{j'}\gamma(\text{E}[\tilde{V}_{ij'',t+1}] - \text{E}[\tilde{V}_{ij',t+1}])
\end{aligned}$$

Here we assume the same bargaining parameter for both transactions. We also assume that

[12]Note that $P_{ijt}$ is a deterministic function of parameters $\chi_i$, $\eta_i$, $t_{0i}$, $t$, $\omega_i$, $\alpha_{0j}$, $\alpha_{1j}$, $\alpha_{2j}$, $q_j$, $\lambda_{ij}$, and $\beta_j$, of which only the cost function parameters, probability of environmental incident, and discount factor vary across operators.

operator $j'$ holds the well for one period for simplicity, though this expression is easily extended to a more general case.

**Proposition 3:** Given $\gamma > 0$ (i.e., equilibrium well prices permit non-zero seller surplus), operators with high portfolio continuation values $\mathrm{E}[\tilde{V}_{jt}]$ receive additional private surplus under limited liability by transferring wells to operators with low $\mathrm{E}[\tilde{V}_{j't}]$.

This model result helps to expand our understanding of the "judgment proof problem." In the traditional formulation (e.g., Shavell, 1986), firms are "judgment proof" from accidents whose damages exceed their ability to pay. For this reason, concerns about judgment proof firms and the socialized costs of private risk-taking have typically been targeted at small, under-capitalized firms.

By contrast, this model result highlights that large, well-capitalized firms may also benefit from socializing risks – even socializing anticipated end-of-life costs – by strategically transferring assets. Depending on the value of $\gamma$, it is even possible that large firms derive more surplus from limited liability than their smaller counterparts.

*Surety Bond Regulation:*

Suppose the regulator requires all transferred wells to secure a surety bond to pay for environmental incident costs and/or end-of-life cleanup costs in the case of operator bankruptcy. In an actuarially fair market, the cost of the surety bond is equal to the probability that the operator declares bankruptcy times the cost of plugging wells and paying for any environmental incident costs.

We noted above that operators may declare bankruptcy to avoid paying end-of-life plugging costs ("planned bankruptcy") or to avoid paying environmental incident costs ("unplanned bankruptcy"). Therefore, we can decompose the cost of the actuarially fair surety bond obtained in period $\tau$ as follows:

$$\begin{aligned} S^*_{j\tau} = &\sum_{t=\tau} \beta^t \mathrm{Prob}(B^d_{jt} = 1) \cdot [\sum_{i \in I_{jt}} \chi_i] \\ &+ \sum_{t=\tau} \beta^t \sum_{n \in [1, |I_{jt}|]} \mathrm{Prob}(B^s_{jt} | N_t = n) \cdot \mathrm{Prob}(N_t = n) \cdot [\sum_{i \in I_{jt}} \chi_i + n\omega] \end{aligned}$$

Here $N_t$ represents the number of wells with an environmental incident. For notational sim-

plicity, I assume $\omega_i = \omega$ here.

In the current version of the model, "planned bankruptcy" is deterministic. Thus if insurers have full information, this expression becomes:

$$S^*_{j\tau} = (1 - \sum_{t=\tau}^{\tilde{T}^d_j - 1} \sum_{n \in [1,|I_{jt}|]} \text{Prob}(B^s_{jt} = 1 | N_t = n) \cdot \text{Prob}(N_t = n)) \cdot \beta^{\tilde{T}^d_j} \cdot [\sum_{i \in I_{jt}} \chi_i]$$
$$+ \sum_{t=\tau}^{\tilde{T}^d_j - 1} \beta^t \sum_{n \in [1,|I_{jt}|]} \text{Prob}(B^s_{jt} = 1 | N_t = n) \cdot \text{Prob}(N_t = n) \cdot [\sum_{i \in I_{jt}} \chi_i + n\omega]$$

Note that $\tilde{T}^d_j$ may be infinite, in which case the first term becomes 0.

However, insurers may not have full information and may instead form some belief about the probability of either planned or unplanned bankruptcy. In this case, the price that insurer $k$ will charge for a surety bond obtained in period $\tau$ is given by:

$$S_{jk\tau} = \text{E}\Big[(1 - \sum_{t=\tau}^{\tilde{T}^d_j - 1} \sum_{n \in [1,|I_{jt}|]} \text{Prob}(B^s_{jt} = 1 | N_t = n) \cdot \text{Prob}(N_t = n)) \cdot \beta^{\tilde{T}^d_j} \cdot [\sum_{i \in I_{jt}} \chi_i]$$
$$+ \sum_{t=\tau}^{\tilde{T}^d_j - 1} \beta^t \sum_{n \in [1,|I_{jt}|]} \text{Prob}(B^s_{jt} = 1 | N_t = n) \cdot \text{Prob}(N_t = n) \cdot [\sum_{i \in I_{jt}} \chi_i + n\omega] | \mathcal{I}_k \Big]$$

where $\mathcal{I}_k$ represents the information set of insurer $k$.

Next let's consider the impact of the surety bond requirement on operators. First, consider the outcome where all operators must post bonds for all wells, irrespective of transfers. Given an actuarially fair surety bond market, difference in bonding requirements across operators arise from differences in discounted unfunded end-of-life plugging costs and/or differences in the expected discounted costs of bankruptcy due to an environmental incident. If operator $j$ can access capital at a cost of $r_r$ and its surety bond payment accrues interest at rate $r_j$, then surety bond requirements will efficiently correct distortions from limited liability.[13] That is:

$$\text{E}[\tilde{V}^{S^*}_{ijt}] = \text{E}[V_{ijt}]$$

[13]Note that this equivalence also pins down the relationship between $r_j$, the operator's cost of capital and the interest earned on the surety bond premium, and $\beta_j$, the discount factor: $\frac{1}{\beta_j} = 1 + r_j$.

$$\beta \mathrm{E}[\tilde{V}_{ij,t+1}^{S^*}] - S_{jt}^* = \beta \mathrm{E}[V_{ij,t+1}]$$

To simplify for now, we ignore the possibility that a new bonding requirement might induce some operators to declare bankruptcy rather than complying with the regulation.

The remaining value of the well, having posted a surety bond in a regime with limited liability, is exactly equal to the remaining value of the well in a regime without limited liability. Likewise, the adjusted continuation value of the well, conditional on having posted a surety bond, is equal to the continuation value where the well must cover its expected end-of-life costs and environmental incident cleanup costs but receives a "credit" from the surety bond payment plus interest.

Given the option to transfer, the expected value of well $i$ becomes:

$$\mathrm{E}[\tilde{V}_{it}^{S^*}] = \max_{j \in J_t} \pi_{ijt} - \lambda_{ij}\omega_i - \chi_i \cdot P_{ijt} - S_{jt}^* + \beta_j \mathrm{E}[\tilde{V}_{i,t+1}^{S^*} | P_{ijt} = 0] \cdot (1 - P_{ijt})$$

However, if the cost of capital to operator $j$ is $r_j$ and the interest earned on surety bond payments is $r$, where $r_j > r$ due to costly external finance or a high opportunity cost of capital, then the surety bond requirement will also create distortions. The interest earned on the bond premium is no longer sufficient to offset the operator's cost of capital. In this case, we have:

$$\beta \mathrm{E}[\tilde{V}_{ij,t+1}^{S}] - S_{jt} < \beta \mathrm{E}[V_{ij,t+1}]$$

Note that this wedge increases in magnitude with larger bond premium payments, i.e., for operators with higher discounted end-of-life costs or higher probability of environmental incident, conditional on a given operator cost of capital and surety bond interest rate.

**Proposition 4**: Surety bond requirements will underincentivize transfers to operators with higher surety bond requirements and/or higher costs of capital.

When operator $j'$ has a higher bonding requirement than $j$, transfer surplus will be greater in a regime without limited liability than in a regime with limited liability and bonding requirements – that is, incentives to transfer are lower than the socially efficient level. Conversely, incentives to transfer will be higher than the socially efficient level when operator $j'$ has a lower bonding requirement than operator $j$.

Note that this wedge could also arise from bonding requirements only applied to trans-

ferred wells, as opposed to all wells (a policy decision which might arise from concern that some wells would declare bankruptcy if universally subject to a bonding requirement) or from underwriting administrative costs increasing the cost of the surety bond beyond the actuarially fair amount.

# 6 Policy Implications

[in progress]

# 7 Conclusion

In this paper, we document novel empirical facts about ownership transfers of oil and gas well: these transfers occur for many wells and are an important component of oil and gas markets; low-profitability wells are more likely to be transferred in general; and low-profitability wells are more likely to be transferred to low-profitability firms in particular. Furthermore, late-in-life production and plugging outcomes are both correlated with whether wells were transferred at middle age. Taken together with our analytic model, these results are consistent with transfers occurring due to both operator specialization and liability shielding, whether intentional or unintentional.

Our analysis suggests several directions for future research. Further analysis could deepen our understanding of the secondary market for wells – for example, what frictions exist, if any, in identifying buyers for low-producing or non-producing wells. For some well transfers, price information is available in news articles and careful data collection could shed light on the bargaining parameter governing the division of transfer surplus between buyer and seller. More broadly, this analysis raises questions about the management of the growing stock of end-of-life wells, and of end-of-life fossil assets more generally. Given a long history of inadequate bonding requirements, who should pay to clean up these assets, and how can policymakers incentivize efficient behavior by original and subsequent operators?

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# A1 Online Appendix

This Appendix shows additional tables and figures, referenced in the main text.

Table A1: Summary Statistics

| | N | Mean | Median | S.D. | Min | Max |
|---|---|---|---|---|---|---|
| year | 14,072,483 | 2009.0 | 2010 | 8.4 | 1993 | 2023 |
| oil_barrels | 13,670,663 | 2063.3 | 0 | 39760.3 | -90 | 20505979 |
| gas_mcf | 13,670,663 | 21208.4 | 0 | 196123.9 | 0 | 106993784 |
| condensate_barrels | 13,670,663 | 3.2 | 0 | 283.6 | 0 | 219008.1 |
| revenue, '000s | 13,400,995 | 257.9 | 4.5 | 3485.5 | -9.3 | 1774391.4 |
| type==mixed | 14,072,483 | 0.3 | 0 | 0.4 | 0 | 1 |
| type==oil | 14,072,483 | 0.3 | 0 | 0.5 | 0 | 1 |
| type==prod_zero | 14,072,483 | 0.2 | 0 | 0.4 | 0 | 1 |
| sale, preferred | 12,424,050 | 0.07 | 0 | 0.3 | 0 | 5 |
| sale, broad | 12,424,050 | 0.08 | 0 | 0.3 | 0 | 5 |
| sale, narrow | 12,611,319 | 0.05 | 0 | 0.2 | 0 | 5 |
| WTI oil price | 14,072,221 | 76.5 | 67.9 | 32.9 | 19.5 | 189.5 |
| Henry Hub gas price | 12,758,488 | 5.9 | 4.9 | 3.0 | 1.9 | 20.9 |
| natural gas liquids price | 7,622,617 | 10.8 | 10.1 | 4.2 | 3.4 | 21.5 |
| citygate gas price | 14,072,172 | 7.1 | 6.4 | 2.7 | 2.6 | 24.6 |
| oil, first price | 14,072,202 | 71.3 | 65.5 | 33.8 | 17.2 | 185.9 |
| spud year, as reported | 3,846,684 | 1994.9 | 2001 | 18.8 | 1860 | 2026 |
| spud year, with interpolation | 7,744,370 | 1986.8 | 1990 | 22.2 | 1860 | 2026 |
| first year of production | 3,838,238 | 2004.9 | 2005 | 5.9 | 1994 | 2023 |
| start of production not observed | 14,072,483 | 0.7 | 1 | 0.5 | 0 | 1 |
| age | 10,126,437 | 18.4 | 12.5 | 20.9 | -33 | 141 |
| revenue in first year, '000s | 6,464,437 | 2227.7 | 644.3 | 7748.9 | 0 | 652720.9 |
| revenue as a portion of initial | 5,243,636 | 0.5 | 0.07 | 28.5 | -0.0005 | 16835.3 |
| region==CA, In | 14,072,483 | 0.3 | 0 | 0.5 | 0 | 1 |
| region==CA, No | 14,072,483 | 0.01 | 0 | 0.1 | 0 | 1 |
| region==CA, So | 14,072,483 | 0.04 | 0 | 0.2 | 0 | 1 |
| region==CO, NE | 14,072,483 | 0.04 | 0 | 0.2 | 0 | 1 |
| region==CO, NW | 14,072,483 | 0.02 | 0 | 0.1 | 0 | 1 |
| region==CO, SE | 14,072,483 | 0.006 | 0 | 0.07 | 0 | 1 |
| region==CO, SW | 14,072,483 | 0.005 | 0 | 0.07 | 0 | 1 |
| region==PA, conventional | 14,072,483 | 0.1 | 0 | 0.3 | 0 | 1 |
| region==PA, unconvent. | 14,072,483 | 0.007 | 0 | 0.08 | 0 | 1 |
| region==TX, Barnett | 14,072,483 | 0.1 | 0 | 0.3 | 0 | 1 |
| region==TX, Eagle Ford | 14,072,483 | 0.1 | 0 | 0.3 | 0 | 1 |
| region==TX, Granite Wash | 14,072,483 | 0.04 | 0 | 0.2 | 0 | 1 |
| region==TX, Haynesville | 14,072,483 | 0.04 | 0 | 0.2 | 0 | 1 |
| region==TX, Permian | 14,072,483 | 0.1 | 0 | 0.3 | 0 | 1 |
| region==TX, unknown | 14,072,483 | 0.003 | 0 | 0.06 | 0 | 1 |
| plugged | 7,545,760 | 0.2 | 0 | 0.4 | 0 | 1 |
| operator well count | 14,072,483 | 14949.2 | 1947.8 | 23872.4 | 1 | 77620 |
| operator state-wide revenue, '000,000's | 14,072,483 | 123172.3 | 23932.0 | 183424.1 | 0 | 1647828.1 |

Note: The unit of observation is a well in a year. The panel is an unbalanced panel covering California, Colorado, Pennsylvania, and Texas; details in text.

## Table A2: Wells Are Frequently Sold

| | N | Mean |
|---|---|---|
| Sale, preferred | 14,476,800 | 0.058 |
| If producing | 7,809,013 | 0.076 |
| If non-producing | 6,667,787 | 0.037 |
| Sale, broad | 14,476,800 | 0.074 |
| If producing | 7,809,013 | 0.095 |
| If non-producing | 6,667,787 | 0.051 |
| Sale, narrow | 14,908,942 | 0.042 |
| If producing | 7,894,745 | 0.054 |
| If non-producing | 7,014,197 | 0.027 |

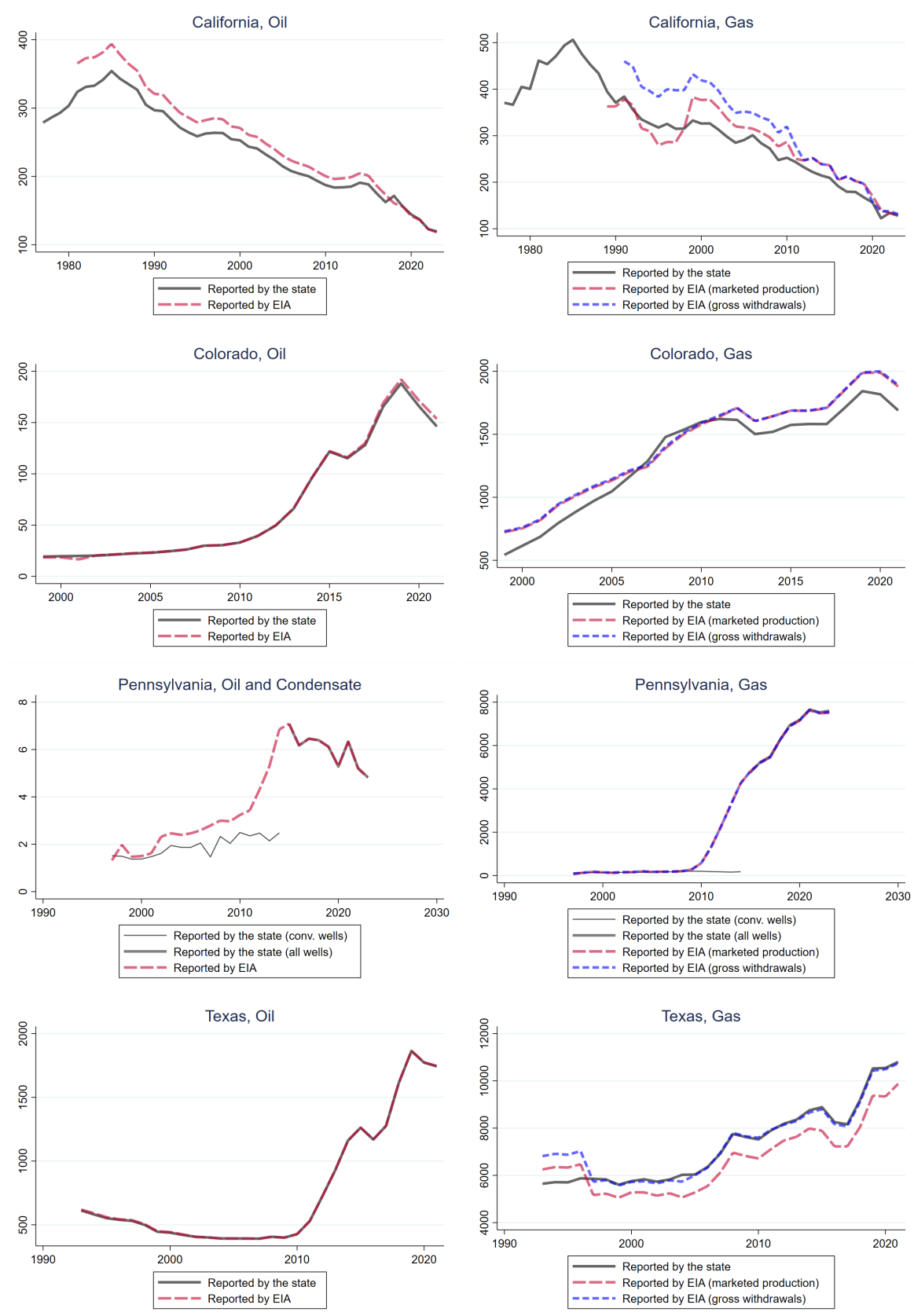
Note: The unit of observation is a well in a year. The panel is an unbalanced panel covering California, Colorado, Pennsylvania, and Texas; details in text. The preferred definition of a sale is a change in ownership where the old and new owner names are not too similar and notable mergers (e.g., Chevron-Texaco) are not included as sales. The broad definition includes sales of similarly-named firms as well as mergers like Chevron-Texaco. The narrow definition begins with the preferred definition, but does not count as a sale a transfer to a newly created firm, a transfer from a disappearing firm, nor sales at the initial time of production.

## Table A3: Wells Are Frequently Sold, Robustness

| | N | Mean |
|---|---|---|
| All wells | 10,428,716 | 0.075 |
| Recent observations (2012-2021) | 4,247,556 | 0.084 |
| California | 2,627,182 | 0.038 |
| Colorado | 843,518 | 0.074 |
| Pennsylvania | 1,831,356 | 0.050 |
| Texas | 5,126,660 | 0.102 |
| Gas-only wells | 3,297,520 | 0.086 |
| Wells with both oil and gas | 3,024,690 | 0.088 |
| Oil-only wells | 3,239,327 | 0.053 |
| Small size wells | 6,684,394 | 0.075 |
| Large size wells | 3,744,322 | 0.074 |
| Wells with truncated history | 5,238,271 | 0.075 |
| Wells with full history | 5,190,445 | 0.074 |
| Young wells (less than or equal to 11 years) | 3,526,572 | 0.071 |
| Old wells | 3,573,796 | 0.062 |
| Wells with age missing | 3,328,348 | 0.091 |
| Wells with small size at start | 2,551,341 | 0.074 |
| Wells with large size at start | 2,470,146 | 0.072 |
| Wells with missing data on size at start | 5,407,229 | 0.076 |

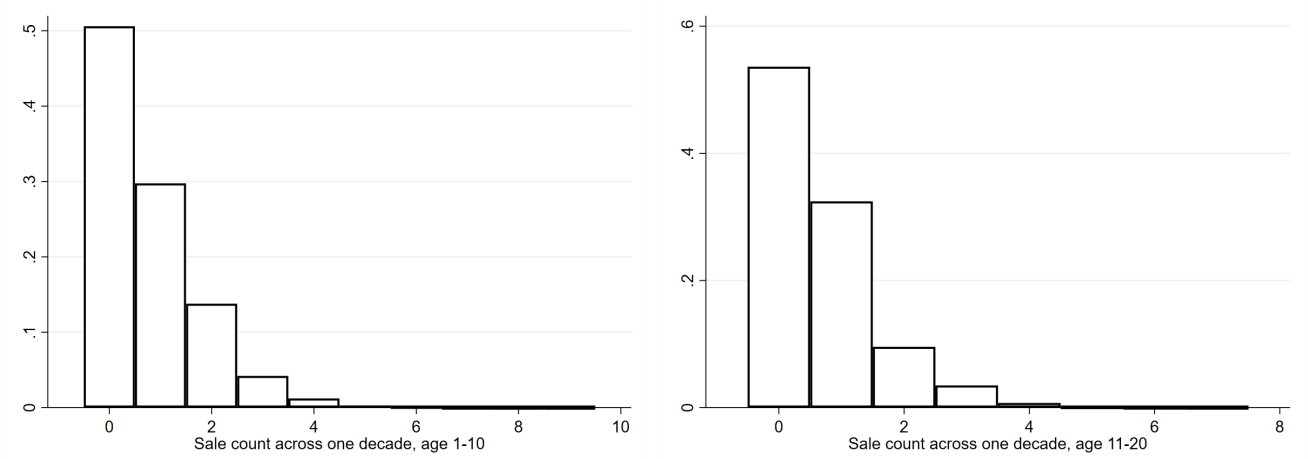
Note: The main text describes how the typical well-by-year observation has a mean of 0.075 (roughly corresponding to 7.5% of wells are sold in any given year; but recall that the sale count is occasionally greater than 1 in a year). This table shows how the mean value varies across subsamples.

Figure A1: Observed Production Compared to EIA Totals




Note: This figure compares observed oil and gas productions in each state to what is reported by the EIA. Oil production is in million barrels per year. Gas production is in bcf per year. Sample periods vary across states because of data availability. Oil totals match well in most states, except that PA data exclude oil and condensate from unconventional wells prior to 2015. Gas totals are highly correlated with EIA magnitudes and of comparable magnitude to EIA totals, but match less well than do oil totals. PA also excludes gas from unconventional wells prior to 2015.

Figure A2: Some Wells Are Sold Frequently, Robustness




Note: This graph matches Figure 2 in the main text, but for a separate subsample. Rather than observing a single well every year for ages 1-20, we observe wells every year for ages 1-10 (left panel, N=180,034) or ages 11-20 (right panel, N=78,231). This has the advantage of increasing the sample size relative to what we have in Figure 2, but we must now consider joint probabilities to be able to compare the decadal results to the twenty-year results. If the probabilities across the two decades were independent, we would expect to see 25% of wells experience zero sales in twenty years, 32% one sale, 23% two sales, and 20% three or more sales. This is similar to what we see in Figure 2, in which 25% experience zero sales, 26% one sale, 22% two sales, and 27% three or more sales.

Table A4: Low-value wells are sold more often, robustness

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|
| CV (log) | -0.006*** | | | | | | | -0.006*** | -0.007*** |
| | (0.001) | | | | | | | (0.001) | (0.001) |
| Revenue (log) | | -0.006*** | | | | | | | |
| | | (0.001) | | | | | | | |
| CV, winsorized (log) | | | -0.006*** | | | | | | |
| | | | (0.001) | | | | | | |
| CV, alt. decline curve (log) | | | | -0.006*** | | | | | |
| | | | | (0.001) | | | | | |
| CV, high prices (log) | | | | | -0.004*** | | | | |
| | | | | | (0.001) | | | | |
| CV, alt. commodity prices (log) | | | | | | -0.006*** | | | |
| | | | | | | (0.001) | | | |
| Age (log) | | | | | | | 0.003** | | |
| | | | | | | | (0.001) | | |
| Observations | 7,197,388 | 7,291,655 | 7,197,388 | 7,158,004 | 7,478,379 | 6,572,713 | 8,819,447 | 2,065,399 | 2,778,633 |
| $R^2$ | 0.02 | 0.01 | 0.02 | 0.02 | 0.01 | 0.01 | 0.02 | 0.01 | 0.01 |

| | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) |
|---|---|---|---|---|---|---|---|---|---|
| CV (log) | -0.003 | -0.005*** | -0.004*** | -0.009*** | -0.006*** | -0.006*** | -0.006*** | -0.004** | -0.007*** |
| | (0.002) | (0.001) | (0.001) | (0.001) | (0.001) | (0.001) | (0.002) | (0.002) | (0.001) |
| Observations | 1,438,719 | 7,197,388 | 7,266,583 | 3,606,967 | 3,606,959 | 1,720,550 | 725,985 | 1,263,977 | 3,486,876 |
| $R^2$ | 0.02 | 0.01 | 0.01 | 0.02 | 0.09 | 0.01 | 0.00 | 0.00 | 0.00 |

Note: This table is like Table 2 in the main text, but with alternative variable definitions and subsamples. Column 1 recreates the results from Column 1 of Table 2. Column 2 uses logged revenue rather than logged continuation value (c.v.). Column 3 winsorizes c.v. Column 4 uses an alternative estimate for well decline curves in the c.v. calculation. Column 5 uses a high commodity price scenario for c.v. Column 6 uses WTI and Henry Hub prices, rather than state-level commodity prices. Column 7 uses age rather than c.v. Column 8 drops observations for which the spud year is interpolated. Column 9 drops wells for which our data are truncated (i.e. the well is not observed from its start year). Column 10 limits the sample to 2017-2021. Column 11 uses a broader definition of a sale; Column 12 uses a narrower definition. Column 13 controls for county effects, not only region effects; and it adds a control for the log of initial revenue. Column 14 controls for both the log of initial revenue and the interaction of region, type, and year effects. Columns 15-18 limit the sample to individual states (California, Colorado, Pennsylvania, and Texas, in that order).

Table A5: Low-value wells are sold to low-value firms, robustness

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|
| CV (log) | 0.095*** | | | | | | | 0.135*** | 0.108*** |
| | (0.016) | | | | | | | (0.028) | (0.023) |
| Revenue (log) | | 0.054*** | | | | | | | |
| | | (0.013) | | | | | | | |
| CV, winsorized (log) | | | 0.092*** | | | | | | |
| | | | (0.016) | | | | | | |
| CV, alt. decline curve (log) | | | | 0.098*** | | | | | |
| | | | | (0.015) | | | | | |
| CV, high prices (log) | | | | | 0.034*** | | | | |
| | | | | | (0.011) | | | | |
| CV, alt. commodity prices (log) | | | | | | 0.094*** | | | |
| | | | | | | (0.017) | | | |
| Age (log) | | | | | | | -0.191*** | | |
| | | | | | | | (0.041) | | |
| Observations | 506,590 | 543,931 | 506,590 | 503,354 | 522,279 | 463,241 | 483,197 | 114,735 | 230,431 |
| $R^2$ | 0.04 | 0.03 | 0.05 | 0.04 | 0.03 | 0.07 | 0.05 | 0.15 | 0.08 |

| | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) |
|---|---|---|---|---|---|---|---|---|---|
| CV (log) | 0.100*** | 0.089*** | 0.102*** | 0.121*** | 0.054 | 0.094** | 0.028 | 0.126*** | 0.071*** |
| | (0.020) | (0.015) | (0.020) | (0.017) | (.) | (0.041) | (0.031) | (0.038) | (0.016) |
| Observations | 129,581 | 638,406 | 368,996 | 261,182 | 261,136 | 58,735 | 51,196 | 64,995 | 331,664 |
| $R^2$ | 0.17 | 0.03 | 0.04 | 0.11 | 0.35 | 0.02 | 0.04 | 0.15 | 0.01 |

Note: This table is like Table 3 in the main text, but with alternative variable definitions and subsamples. Column 1 recreates the results from Column 1 of Table 3. Column 2 uses logged revenue rather than logged continuation value (c.v.). Column 3 winsorizes c.v. Column 4 uses an alternative estimate for well decline curves in the c.v. calculation. Column 5 uses a high commodity price scenario for c.v. Column 6 uses WTI and Henry Hub prices, rather than state-level commodity prices. Column 7 uses age rather than c.v. Column 8 drops observations for which the spud year is interpolated. Column 9 drops wells for which our data are truncated (i.e. the well is not observed from its start year). Column 10 limits the sample to 2017-2021. Column 11 uses a broader definition of a sale; Column 12 uses a narrower definition. Column 13 controls for county effects, not only region effects; and it adds a control for the log of initial revenue. Column 14 controls for both the log of initial revenue and the interaction of region, type, and year effects. Columns 15-18 limit the sample to individual states (California, Colorado, Pennsylvania, and Texas, in that order).

Table A6: Long-run outcomes: relative size, robustness

| | (1) v2 | (2) v3 | (3) v4 | (4) v6 | (5) v7 | (6) v8 | (7) v9 | (8) v10 | (9) v11 | (10) vCA | (11) vCO | (12) vPA | (13) vTX |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sale_interm_age1_5 | | | | | | -0.00 | | | | | | | |
| | | | | | | (0.00) | | | | | | | |
| sale_interm_age6_10 | | | | | | -0.00 | | | | | | | |
| | | | | | | (0.00) | | | | | | | |
| sale_interm_age11_15 | | | | -0.01** | | -0.00 | | | | | | | |
| | | | | (0.00) | | (0.00) | | | | | | | |
| Ever sold, age 16-20 | | | 0.00 | | | -0.00 | -0.00 | -0.00 | -0.01 | 0.00 | 0.02*** | -0.02 | 0.00 |
| | | | (0.00) | | | (0.00) | (0.01) | (0.00) | (0.00) | (0.01) | (0.01) | (0.01) | (0.00) |
| sale_interm_age21_25 | | | | | 0.00 | | | | | | | | |
| | | | | | (0.00) | | | | | | | | |
| sale_broad_age16_20 | -0.01* | | | | | | | | | | | | |
| | (0.00) | | | | | | | | | | | | |
| sale_narrow_age16_20 | | -0.00 | | | | | | | | | | | |
| | | (0.00) | | | | | | | | | | | |
| Observations | 72,862 | 72,862 | 51,627 | 128,898 | 37,140 | 71,893 | 72,885 | 43,528 | 72,526 | 34,994 | 1,735 | 14,065 | 21,732 |
| $R^2$ | 0.43 | 0.43 | 0.41 | 0.36 | 0.35 | 0.43 | 0.42 | 0.47 | 0.44 | 0.31 | 0.59 | 0.51 | 0.42 |

Note:

Table A7: Long-run outcomes: producing indicator, robustness

| | (1) v2 | (2) v3 | (3) v4 | (4) v6 | (5) v7 | (6) v8 | (7) v9 | (8) v10 | (9) v11 | (10) vCA | (11) vCO | (12) vPA | (13) vTX |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sale_interm_age1_5 | | | | | | 0.01 | | | | | | | |
| | | | | | | (0.01) | | | | | | | |
| sale_interm_age6_10 | | | | | | -0.04*** | | | | | | | |
| | | | | | | (0.01) | | | | | | | |
| sale_interm_age11_15 | | | | 0.00 | | -0.04*** | | | | | | | |
| | | | | (0.01) | | (0.01) | | | | | | | |
| Ever sold, age 16-20 | | | 0.00 | | | 0.03 | 0.03 | 0.03** | 0.03 | 0.01 | 0.07** | 0.01 | 0.03** |
| | | | (0.03) | | | (0.02) | (0.02) | (0.01) | (0.02) | (0.05) | (0.03) | (0.01) | (0.01) |
| sale_interm_age21_25 | | | | | 0.07** | | | | | | | | |
| | | | | | (0.03) | | | | | | | | |
| sale_broad_age16_20 | 0.05** | | | | | | | | | | | | |
| | (0.02) | | | | | | | | | | | | |
| sale_narrow_age16_20 | | 0.03 | | | | | | | | | | | |
| | | (0.02) | | | | | | | | | | | |
| Observations | 72,862 | 72,862 | 51,627 | 128,898 | 37,140 | 71,893 | 72,885 | 43,528 | 72,526 | 34,994 | 1,735 | 14,065 | 21,732 |
| $R^2$ | 0.28 | 0.27 | 0.28 | 0.23 | 0.28 | 0.28 | 0.25 | 0.25 | 0.28 | 0.20 | 0.23 | 0.04 | 0.19 |

Note:

Table A8: Long-run outcomes: relative size if producing, robustness

| | (1) v2 | (2) v3 | (3) v4 | (4) v6 | (5) v7 | (6) v8 | (7) v9 | (8) v10 | (9) v11 | (10) vCA | (11) vCO | (12) vPA | (13) vTX |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sale_interm_age1_5 | | | | | | -0.01* | | | | | | | |
| | | | | | | (0.00) | | | | | | | |
| sale_interm_age6_10 | | | | | | -0.00 | | | | | | | |
| | | | | | | (0.00) | | | | | | | |
| sale_interm_age11_15 | | | | -0.01* | | 0.00 | | | | | | | |
| | | | | (0.00) | | (0.01) | | | | | | | |
| Ever sold, age 16-20 | | | 0.01 | | | -0.00 | -0.00 | -0.00 | -0.00 | 0.01 | 0.02** | -0.02* | 0.00 |
| | | | (0.01) | | | (0.01) | (0.01) | (0.01) | (0.01) | (0.01) | (0.01) | (0.01) | (0.00) |
| sale_interm_age21_25 | | | | | -0.01 | | | | | | | | |
| | | | | | (0.00) | | | | | | | | |
| sale_broad_age16_20 | -0.01*** | | | | | | | | | | | | |
| | (0.00) | | | | | | | | | | | | |
| sale_narrow_age16_20 | | -0.00 | | | | | | | | | | | |
| | | (0.01) | | | | | | | | | | | |
| Observations | 47,473 | 47,473 | 29,623 | 97,620 | 18,140 | 46,982 | 47,496 | 31,026 | 47,473 | 16,812 | 1,533 | 13,322 | 15,806 |
| $R^2$ | 0.44 | 0.44 | 0.41 | 0.38 | 0.35 | 0.44 | 0.42 | 0.48 | 0.44 | 0.30 | 0.64 | 0.54 | 0.46 |

Note:

Table A9: Long-run outcomes: plugged indicator, robustness

| | (1) v2 | (2) v3 | (3) v4 | (4) v6 | (5) v7 | (6) v8 | (7) v9 | (8) v10 | (9) v11 | (10) vCA | (11) vCO | (12) vPA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sale_interm_age1_5 | | | | | | -0.04 | | | | | | |
| | | | | | | (0.03) | | | | | | |
| sale_interm_age6_10 | | | | | | 0.02 | | | | | | |
| | | | | | | (0.01) | | | | | | |
| sale_interm_age11_15 | | | | -0.03*** | | -0.00 | | | | | | |
| | | | | (0.01) | | (0.01) | | | | | | |
| Ever sold, age 16-20 | | | -0.05 | | | -0.05 | -0.06 | -0.07** | -0.05 | -0.07 | 0.01 | -0.00 |
| | | | (0.04) | | | (0.03) | (0.04) | (0.03) | (0.03) | (0.05) | (0.01) | (0.00) |
| sale_interm_age21_25 | | | | | -0.14*** | | | | | | | |
| | | | | | (0.05) | | | | | | | |
| sale_broad_age16_20 | -0.06* | | | | | | | | | | | |
| | (0.03) | | | | | | | | | | | |
| sale_narrow_age16_20 | | -0.05 | | | | | | | | | | |
| | | (0.03) | | | | | | | | | | |
| Observations | 51,554 | 51,554 | 39,362 | 80,411 | 31,446 | 50,557 | 51,574 | 22,016 | 50,794 | 34,994 | 1,735 | 14,065 |
| $R^2$ | 0.17 | 0.17 | 0.17 | 0.16 | 0.17 | 0.17 | 0.14 | 0.23 | 0.18 | 0.12 | 0.06 | 0.02 |

Note:

Table A10: Long-run outcomes: plugged conditional on non-producing, robustness

| | (1) v2 | (2) v3 | (3) v4 | (4) v6 | (5) v7 | (6) v8 | (7) v9 | (8) v10 | (9) v11 | (10) vCA | (11) vCO | (12) vPA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sale_interm_age1_5 | | | | | | -0.06 | | | | | | |
| | | | | | | (0.05) | | | | | | |
| sale_interm_age6_10 | | | | | | 0.00 | | | | | | |
| | | | | | | (0.03) | | | | | | |
| sale_interm_age11_15 | | | | -0.14*** | | -0.07** | | | | | | |
| | | | | (0.03) | | (0.03) | | | | | | |
| Ever sold, age 16-20 | | | -0.10** | | | -0.12** | -0.13** | -0.26*** | -0.12** | -0.12** | 0.09 | -0.02 |
| | | | (0.05) | | | (0.05) | (0.06) | (0.08) | (0.05) | (0.05) | (0.06) | (0.03) |
| sale_interm_age21_25 | | | | | -0.23*** | | | | | | | |
| | | | | | (0.05) | | | | | | | |
| sale_broad_age16_20 | -0.10** | | | | | | | | | | | |
| | (0.04) | | | | | | | | | | | |
| sale_narrow_age16_20 | | -0.11** | | | | | | | | | | |
| | | (0.05) | | | | | | | | | | |
| Observations | 19,333 | 19,333 | 18,092 | 20,708 | 17,102 | 18,866 | 19,364 | 6,452 | 19,095 | 18,162 | 193 | 740 |
| $R^2$ | 0.10 | 0.10 | 0.09 | 0.15 | 0.09 | 0.10 | 0.06 | 0.18 | 0.11 | 0.08 | 0.11 | 0.41 |

Note:

Table A11: Some long-run outcomes vary by whether a well is sold

| | Indicator, Producing | Production, If Non-Zero | Production (Relative) | Plugged Status | Plugged, If Non-Producing |
|---|---|---|---|---|---|
| Ever sold, age 16-20 | 0.022 | -0.004 | -0.005 | -0.029 | -0.090*** |
| | (0.018) | (0.005) | (0.005) | (0.018) | (0.032) |
| Observations | 67,693 | 47,467 | 67,693 | 46,370 | 14,177 |
| $R^2$ | 0.22 | 0.44 | 0.42 | 0.07 | 0.05 |

Note: The unit of observation is a well at age 21. The dependent variable is listed at the top of each column; see text for details. For instance, relative production is production at age 21, scaled by production at age 1. The right-hand side variable of interest is an indicator for whether any sale occurred at age 16 to 20, i.e. in the five years running up to age 21. Note oil and gas production have been combined using a time-invariant ratio of 70 barrels to 4 mcf, roughly reflecting typical oil versus gas prices. Initial production is production at age 1, and pre-sale production is relative production at age 14. All columns also control for region by type by year indicators. Standard errors are clustered by the interaction of owner at age 16 and owner at age 21. Robustness checks are shown in the Appendix.

Table A12: Producing at age 14

| | Indicator, Producing | Production, If Non-Zero | Production (Relative) | Plugged Status | Plugged, If Non-Producing |
|---|---|---|---|---|---|
| Ever sold, age 16-20 | 0.008 | -0.007 | -0.009 | -0.009 | -0.047* |
| | (0.013) | (0.005) | (0.005) | (0.008) | (0.027) |
| Observations | 56,096 | 45,963 | 56,096 | 38,000 | 7,016 |
| $R^2$ | 0.11 | 0.47 | 0.42 | 0.04 | 0.07 |

Note:

Table A13: Not producing at age 14

| | Indicator, Producing | Production, If Non-Zero | Production (Relative) | Plugged Status | Plugged, If Non-Producing |
|---|---|---|---|---|---|
| Ever sold, age 16-20 | 0.075*** | 0.015 | 0.016*** | -0.136*** | -0.139*** |
| | (0.022) | (0.021) | (0.005) | (0.045) | (0.042) |
| Observations | 11,566 | 1,458 | 11,566 | 8,344 | 7,128 |
| $R^2$ | 0.17 | 0.24 | 0.10 | 0.07 | 0.06 |

Note: