Price Elasticity of Supply and Productivity: An Analysis of Natural Gas Wells in Wyoming *

by

Charles F. Mason† and Gavin Roberts‡

Abstract

Economists and petroleum engineers view natural gas supply from quite different perspectives. Economists focus on the role played by market signals, while petroleum engineers focus on the geological characteristics of natural gas reservoirs. We analyze a large dataset of well-level natural gas production from Wyoming in order to tease out the respective roles played by market signals and geological characteristics in natural gas supply. We find that geological characteristics are the primary determinant of production at the individual well level, while natural gas producers respond to market signals through drilling rates and locations. We show this by estimating price-elasticities of production on three margins: production from previously drilled wells, peak-production rates from new wells, and drilling rates. Our estimation of the price-elasticity of production from previously drilled wells uses a novel fixed effects approach based on petroleum-engineering knowledge. We argue that the price-elasticity of drilling likely depends on the state of well-level productivity. Well-level productivity changed in Wyoming during our sample period, as a result of increased use of new technologies. We show that this change in well-level productivity was accompanied by a simultaneous change in the price-elasticity of supply.

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*Contact author: Mason, phone: +1-307-766-2178; fax: +1-307-766-5090; e-mail: bambuzlr@uwyo.edu.
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†H.A. True Chair in Petroleum and Natural Gas Economics, Department of Economics and Finance, University of Wyoming; Resources for the Future Visiting Fellow; and Visiting Professor, Grantham Institute, London School of Economics, London, UK

‡Department of Economics and Finance, University of Wyoming

1 Introduction

Traditional economic analysis shows that intra-firm supply and aggregate supply of commodities are increasing in price. In the crude oil and natural gas industries, the atomistic units of production are wells, so economists would expect well-level production to be positively related to price. However, petroleum engineers tend to treat production levels from individual wells as resulting from the geological characteristics of the underlying hydrocarbon reservoir. In this paper, we empirically analyze three margins on which natural gas producers may react to changes in natural gas prices: intra-well production rates given an initial-production or peak-production rate, initial-production or peak-production rate, and well-drilling rates. We show that well-drilling rates represent the important margin on which natural gas producers make economic decisions, while intra-well production rates are dictated by geological characteristics of the underlying reservoir, and the state of drilling technology.

Natural gas wells can be conceptualized as factories that produce natural gas. If natural gas prices increase, and there are no exogenous constraints to production then as economists we expect producers to build larger factories. We would also expect production from pre-existing factories to increase production when prices increase. Finally, we would expect more factories to be built when prices increase. However, to the extent that initial-production rates (the size of the factory) and intra-well production rates (production from pre-existing factories) are given exogenously by the underlying geological characteristics of the reservoir, we cannot expect these factors to vary by price. On the other hand, the rate

at which wells are drilled is an endogenous decision, and represents one important margin at which natural gas producers make marginal production decisions. It may be argued that intra-well production rates respond to price changes if producers can vary the inputs used in the production process. For example, by increasing the amount of water used when hydraulically fracturing a well (Fitzgerald, 2015). This means producers may be able increase intra-well production on the initial-production margin, and/or adjust production rates from pre-existing wells. However, if intra-well production is purely exogenously determined by geological characteristics then producers can only choose drilling rates and which wells to drill. This leads to a possibly interesting departure from classical economic theory. When prices increase, less productive wells become profitable, so marginal wells will be less productive, and average intra-well production might decrease. Therefore, average intra-well production might be inversely related to price. The question of whether intra-well production is increasing or decreasing in price is empirical, and we answer that question in this paper.

Our results indicate that the petroleum engineering view of intra-well production prevails. We derive a structural empirical model based on petroleum engineering knowledge and test it using a large dataset of natural gas wells in Wyoming. Our estimates indicate that the natural gas supply from pre-existing wells is extremely inelastic with a statistically-significant point estimate of 0.03, so in our sample intra-well production from pre-existing wells increases by only 0.3% when prices increase 10%. The petroleum-engineering view also prevails for initial-production rates: we find that the elasticity of initial or peak-

production is -0.12, so a 10% increase in price is associated with a decrease in initial-production of approximately 1.2%. Finally, we find that the price-elasticity of drilling is between 0.6 and 0.8 depending on the price series used for estimation and estimation strategy, so a 10% increase in price is associated with a 6% to 8% increase in monthly drilling rates. We also find the price elasticity of drilling increased significantly when new technologies increased well-level productivity. These results qualify the importance of taking account of geological characteristics in analyses of crude oil and natural gas supply, and they indicate that the key marginal production unit in the natural gas industry is the well.

Substantial changes in natural gas production technology occurred during the time period of our sample (1994 to 2012) in Wyoming. The most important change was a large increase in the use of directional drilling and hydraulic fracturing.[1] There are several reasons why we might expect these technological changes to affect well-level productivity, so they must be controlled for in our analysis. For example, the use of directional drilling and hydraulic fracturing unlocked new reservoirs with different geological characteristics than conventional reservoirs. Also, there is evidence that firms learn how to use these new technologies more productively over time (Fitzgerald, 2015), however, firms might also drill the "sweet spots" first, and move to less productive prospects over time. We control for such factors by including year dummy variables and drilling direction dummy variables in our regressions of intra-well production. This allows us to analyze how well-level productivity has evolved over time.

Our analysis of well productivity shows that natural gas production from wells drilled

[1] See Figure 3.

using new technologies – primarily directional drilling and fracking – tend to decline at a faster rate than wells drilled into conventional reservoirs using older technology – vertical drilling. On the other hand, wells drilled using new technology tend to have higher initial production rates. We show that these higher initial production rates result from successful firms moving towards the most productive areas of the unconventional resource base unlocked by new technologies. After controlling for firm effects, formation effects, and prices in our analysis of initial-production rate, we find that initial-production rates have decreased in recent years. Along with our price-elasticity of supply estimates that indicate inelastic supply at all margins, these productivity trends imply that substantial price increases will be required to maintain current aggregate production levels from Wyoming in the future.

2 Background

Economists and petroleum engineers approach the analysis of natural gas and crude oil production differently. While economists focus on incentives and market signals, engineers focus on geology. In our view, a robust econometric model must consider both views. Recent economic analyses have shown the importance of integrating geological characteristics of crude oil production into economic models (Anderson et al., 2014; Mason and van 't Veld, 2013). In this paper, we extend this line of research to natural gas production, as natural gas production and oil production are subject to similar geological characteristics (Cronquist, 2001).

Petroleum engineers generally view natural gas and crude oil production from individual wells as following a "decline curve," wherein production falls over time at a rate that is determined by geological characteristics of the producing area (Baihly et al., 2010; Gullickson et al., 2014; King, 2012). The rate at which production declines from one time period to the next is called the "decline rate," and the process of estimating such decline rates is referred to as "decline-curve analysis." If the decline rate is constant over the life of the well, then decline is said to be "exponential." Petroleum engineers generally allow for the possibility that the decline rate will decrease over time, in which case decline is said to be "hyperbolic" (Cronquist, 2001).

Under exponential decline, natural gas production from well i at calendar time t, q_{it}, is a function of the initial production rate, q_{i0}, the decline rate, b, and the number of periods since well i was drilled, m_i:[2]

$$q_{it} = q_{i0} e^{-bm_i}, \tag{1}$$

with $b \in (0,1)$. Under hyperbolic decline, the decline rate depends on the time elapsed since the well reached peak production. This phenomenon can be approximated by allowing for different decline rates during different eras in the well's life. In the empirical analysis below we allow for three different decline rates: one during the first year of production, one during the second year of production, and one during the third year of production.

[2] We take a "period" to be a month. If well i was drilled in month τ, then $m = t - \tau$. Note that Equation (1) implies the maximum production rate occurs in the initial production period, which is commonly true in our sample.

Equation (1) implies the log-linear relationship

$$\ln(q_{it}) = \ln(q_{i0}) - bm_i. \tag{2}$$

An economist might view equation (2) with some skepticism, as it implies the price elasticity of supply within a natural gas well is zero. This is counter to Hotelling (1931)'s seminal analysis, which implies the production rate from a fixed stock should increase when price increases. Recent theoretical and empirical research suggests the intra-well price elasticity of supply may indeed be zero (Anderson et al., 2014; Mason and van 't Veld, 2013). Anderson et al. (2014) show the incentive to decrease production from a well subject to production decline is small even when higher prices are expected in future time periods. This is because not all of the shelved oil or natural gas can be extracted immediately when prices are high, the product will continue to flow at rates dictated by the underlying geological characteristics. We test this hypothesis in the empirical section to follow. If the intra-well elasticity of supply is zero then from an economic perspective natural gas producers should respond to market signals through an increase in the "drilling rate" – the rate at which new wells are drilled. In general, the manner in which producers respond to prices through drilling rates will depend on well-level productivity, because productivity at the well level will determine the number of potential wells that become profitable when price increases.

Equation (1) suggests that well-level productivity changes may occur in two distinct ways. First, a change in productivity might influence the pattern of decline for a typical

well. For example, in the simple case of exponential decline, a change in productivity might decrease the constant decline rate of the average well. This type of productivity change is illustrated in Figure 1. The wells illustrated in Figure 1 have the same initial production rate, but production declines more slowly after the productivity change. Second, a change in productivity might increase the initial or peak-production rate of the average well. This type is illustrated in Figure 2. The wells illustrated in Figure 2 have the same decline rates, but different initial-production rates.

Traditionally, economists expect technological advancement to increase the marginal productivity of labor or capital. In the case of wells we would expect technological advancement to increase well-level productivity. However, new extractive technology in the natural gas industry has primarily led to an increase in the array of drilling prospects available to producers. There is no ex ante reason to expect a specific direction for well-level productivity changes associated with this increase in drilling prospects. On the other hand, well-level productivity changes associated with new technologies and the hydrocarbon reservoirs these technologies have unlocked will influence production in ways unrelated to changes in price, and thus must be controlled for in our empirical analysis.

3 Empirical Analysis

Our empirical analysis consists of three parts. First, we apply a novel strategy to estimate the decline-rate structures of wells, test whether intra-well production depends on prices, and test whether these decline structures have systematically changed since the onset of

unconventional drilling in Wyoming. This analysis controls for productivity differences associated with initial-production rates by using a fixed-effects model. We estimate the decline profiles using monthly data from the first three years of a given well's operating life. By focusing on the first three years of production, we avoid comparing decline rates from wells with drastically different production time spans. We also provide evidence that decline rates are unlikely to change substantially after the third year of production.[3]

Second, we estimate the degree to which initial or peak-production rates depend on price, and productivity changes related to initial-production rates.[4] Here, we control for the impact of various time-invariant factors upon the well-specific fixed effects estimated in the first part of our empirical analysis. As these fixed effects reflect idiosyncratic features of each well in the decline rate analysis, they are indicative of well-specific productivity. We show that once these factors are controlled for, the elasticity of peak-production with respect to price is negative, which implies the effect of increasing input employment when prices increase is outweighed by the effect of movement towards less productive prospects when prices increase.

Third, we estimate the price elasticity of drilling rates. This amounts to a simple regression of new wells in a given month on prices in that month. We estimate the price elasticity of drilling rates using spot prices and several future prices, and find the average

[3] It is also true that a large proportion of the total production from a typical well will occur during the first three years of life. For example, with a monthly decline rate of 5%, 80% of total production occurs during the first three years; at a monthly decline rate of 7%, more than 90% of total production occurs during the first three years. The estimated decline rates we discuss below are in this range.

[4] The distinction between initial and peak-production rates is discussed in the Data section. Decline-curve analysis generally assumes that peak-production occurs in the initial production period, but this is not always true.

price elasticity of drilling rates is positive and between 0.6 and 0.8 for the full sample period, so drilling rates are far more responsive to price than intra-well production rates, but are inelastic. Further, we find that drilling rates are more responsive to futures prices than spot prices, which makes sense, because production may not occur for several months after the decision to drill is made. Finally, we find that the price elasticity of drilling increased substantially when new technologies increased well-level productivity.

3.1 Intra-Well Production

The regression equation in this section is built up from equation (2). A regression of $\ln(q_{it})$ on a constant and time since drilling, m_i, will provide an estimate of the exponential decline rate and the natural log of the initial production rate. In determining the length of time to consider for a typical well, we use only the first three years of production. Including all observations, irrespective of the length of time a well is in operation, runs the risk of skewing our results: wells drilled later in the sample, or wells that shut down during the sample period, would have relatively fewer observations than wells that were drilled earlier in the sample and were not shut down. To the extent that these different cohorts of wells exhibit different patterns of decline, including a relatively larger number of observations from the latter cohort than the former cohort could bias the results. By restricting attention to the first three years of production from each well in the sample, we mitigate this effect.

In order to allow for hyperbolic decline, we include variables indicating the production year of well i, $D2_i$, and $D3_i$, where $D2_i = 1$ if well i is in its second year of production, and

0 otherwise, while $D3_i = 1$ if well i is in its third year of production, and 0 otherwise. These variables are interacted with the number of months since well i reached its peak production, m_i. Estimated coefficients on these interactions represent differences between the second-year and third-year decline rates, and the first-year decline rate. We would expect these coefficients to be weakly positive, but smaller than the first-year decline rate in magnitude. Such a pattern in the estimates would indicate the decline rate is decreasing in magnitude as the producing life of a well increases.[5]

To estimate the intra-well price elasticity of supply, we include the natural log of the natural gas price in month t, $\ln(p_t)$. If producers respond to price changes through intra-well production changes, then we would expect the coefficient on the spot price variable to be positive, while if intra-well production rates are given exogenously by geological characteristics then we would expect the coefficient to be zero.

We include two classes of variables to measure the impact of changes in technology and drilling prospects associated with the shale gas revolution upon decline rates.[6] The first class is based on the year in which a well was drilled; we denote these variables as $D2000_i$, $D2001_i, \ldots,$ $D2011_i$ in the pursuant discussion. For example, $D2000_i = 1$ if well

[5] For an alternative analysis of decline functions, see Ikonnikova et al. (2015). These authors perform a similar analysis for the Barnett, Fayetteville, Haynesville and Marcellus Shale plays. Their econometric approach focuses on the geology and assumes a specific decline function, with a pattern that points to a shift relatively faster decline rates after a period of time. Our approach is agnostic about the shift in decline rates: decline rates could rise or fall, depending on wether the estimated coefficients for the second- and third-year effects are smaller – more negative – or larger – less negative – than the estimated first-year decline rate. Accordingly, our empirical methodology provides evidence on the accuracy of Ikonnikova et al's modeling assumption in the Wyoming plays we study. As we see below, our results point to a drop, as opposed to an increase, in decline rates. One can also interpret our econometric approach as subsuming all geologic attributes into well-specific fixed effects.

[6] Ikonnikova et al. (2015, p. 28) argue that the productivity of fracked wells is likely to change over time, and suggest that further analysis of the technology impact on production is warranted.

i was drilled in 2000, and $D2000_i = 0$ otherwise. We limit the drilling years indicated by these variables to include only drilling years in the dataset after 1999, as new extraction technologies in Wyoming did not substantially begin to take hold until after the turn of the century. This phenomenon is illustrated in Figure 3, which shows the number of directional wells began to increase drastically after the turn of the century.[7] We interact the drilling-year indicator variables with m_i; the coefficients on these interaction terms capture the differences in the decline rate for wells drilled in a particular year versus wells drilled before the year 2000. Positive coefficients would indicate that production from these wells declines at a slower pace than wells drilled before 2000, indicating the newer wells are more productive with respect to decline rates, while negative coefficients would be indicative of faster decline and lower well-level productivity with respect to decline rates.[8]

The second class of variables used to measure the impact of new technologies is based on the drilling aspect for a well. Before the broad-based adoption of fracking in Wyoming around the turn of the century, most wells were drilled vertically. More recently directional drilling has increased dramatically; this increase has been accompanied by a sizable decrease in vertical drilling.[9] We define indicator variables for wells drilled directionally or horizontally. These variables are denoted by H_i and D_i, respectively. Again, the drilling direction indicators are interacted with m_i. The interpretation of the coefficient on the in-

[7] The primary type of new technology being applied to wells in shale plays in Wyoming is the combination of directional drilling and hydraulic fracturing. There are also coal bed methane wells in Wyoming, but these wells are excluded from the sample.

[8] See Figure 1

[9] Directionally drilled wells involve a change away from vertical orientation. In this way, they are more like horizontal wells than vertical wells; indeed, horizontal wells are directionally drilled wells that turn more than 80°. Very few horizontal wells are drilled in Wyoming.

teraction between D_i and m_i is the difference between the average decline rate for a directionally drilled well and a vertically drilled well; similarly, the coefficient on the interaction term involving H_i reflects the difference between the average decline rate for a horizontally drilled well and a vertically drilled well.

The regression equation to be estimated is then

$$\begin{aligned}\ln(q_{it}) = \widehat{\ln(q_{i0})} + \beta_1 m_i + \beta_2 D2_i m_i + \beta_3 D3_i m_i \\ + \sum_{l=2000}^{2011} \psi_l Dl_i m_i + \phi_h H_i m_i + \phi_d D_i m_i + \xi \ln(p_t) + \varepsilon_{1,it},\end{aligned} \tag{3}$$

where ε_{it}^1 is a mean-zero error term with variance σ_i^2, and $\widehat{\ln(q_{i0})}$, β_1, β_2, β_3, ψ_l, ϕ_h, ϕ_d, and ξ are parameters to be estimated. The estimated well-level fixed effects, $\widehat{\ln(q_{i0})}$, are also the estimated initial-production rates for each well. These estimates will be collected and serve as the dependent variables in our investigation of initial-production-related price elasticity and productivity described in the next section.

Our panel estimation of decline rates at the well level can be contrasted with previous analyses that use production data aggregated over multiple wells (Höök et al., 2009; Höök and Aleklett, 2008; Kasim and Kemp, 2005). The use of aggregated data to estimate decline rates implicitly assumes production from the various wells exhibits similar patterns of decline, which will be problematic if wells come on line at different points in time. Figure 4 points to this difficulty. Here, we plot aggregate production from several of the largest natural gas fields in Wyoming. Of these fields, the Jonah field is the only one that is conducive to aggregate decline curve estimation, and even in its case a majority of the time

series would need to be dropped, i.e., all observations before the onset of decline would need to be dropped. These observations point to the importance of using well-level data in analyzing production patterns over time.

3.2 Peak Production

In the preceding sub-section, the fixed effects represent estimates of peak production rates for each well, and any elements that are constant across time are subsumed into these fixed effects. As a result, the fixed-effects analysis is unable to identify the role played by time-invariant factors such as the geographic effects such as the natural gas formation the well is drilled into, and the parties involved in the operation such as the firm operating the well. Further, that analysis is unable to estimate the influence of price on the peak production level, which always occurs in the initial period by construction.[10] It is possible that the production decline rate is given exogenously by the geological characteristics, but producers can influence peak production through the use of additional inputs. It is also possible that average peak production decreases when prices increase as less productive wells come on line.

To better understand the role played by such time-invariant characteristics, we evaluate well-specific productivity effects not related to decline. We measure these well-specific productivity effects using the estimated well-level fixed effects from equation 3, $\widehat{\ln(q_{i0})}$, which are estimates of deviations from the natural log of the mean peak production rate

[10] See equation (1) and the Data section.

obtained in the estimation of (3). These data will be represented by FE_i in the analysis to remind the reader that they are the fixed effects from (3). The variables we use in this analysis include the year in which the well was completed, the drilling direction, the geologic formation into which the well was drilled, and the identity of the firm operating the well. We also test responsiveness of peak production rates to changes in price by including the natural log of price in the month the well was drilled. We estimate the regression with spot prices, as the price in the month that peak-production occurs should have the biggest influence on peak-production rates if producers can affect peak-production rates by changing the mix of inputs. The regression equation we use in this part of the analysis is

$$FE_i = \sum_{l=2000}^{2012} \theta_l + Dl_i \omega_h H_i + \omega_d D_i + \sum_{s=1}^{n} \chi_s F_i + \sum_{k=1}^{N} \psi_k O_i + \zeta \ln(p_t) + \varepsilon_{2,i}, \tag{4}$$

where ω_h and ω_d are the initial-production effects of drilling direction, θ_l are the initial-production effects of drilling year l, χ_s are the initial-production effects of formation s, ψ_k are the initial-production effects of operator k and $\varepsilon_{2,i}$ is a mean-zero error term. The price variable, p_t, is the monthly average Henry Hub price in the month peak production occurred. We use the Henry Hub price, which is the U.S. benchmark price for natural gas to avoid endogeneity issues associated with using price hubs near the wells in our sample. The ζ is then our estimate of the price elasticity of peak production rates.

3.3 Drilling

The last possible margin at which natural gas production could respond to price signals is through drilling rates. We estimate a simple regression of the natural log of the count of new natural gas wells appearing in the dataset in each month on the natural log of the natural gas price. The estimation equation is

$$\ln(w_t) = \eta_t \ln(p_t) + \varepsilon_{3,t} \tag{5}$$

where $\ln(w_t)$ is the natural log of the count of new wells in calendar month t, $\ln(p_t)$ is the average spot or futures price in calendar month t depending on the particular specification, and $\varepsilon_{3,t}$ is a mean-zero error term. There are several possible estimation issues associated with (5). For example, the number of wells drilled in Wyoming may affect Henry Hub prices, and non-stationarity in Henry Hub prices and new well counts may lead to spurious results. We will discuss robustness checks performed associated with these issues in the results section.

3.4 Data

Our original data set contains 17,425 natural gas wells with unique identifying numbers from the Wyoming Oil and Gas Conservation Commission. Associated with these wells are approximately 2.8 million individual monthly production observations. We examined this dataset in great detail to identify duplicate observations, data anomalies, and wells with

an insufficient number of observations.

We first identified duplicate natural gas well/month observations. There are two reasons that a natural gas well might have duplicate month observations: the natural gas well may have been erroneously entered into the system twice, or the well might have been drilled into multiple reservoirs. Duplicate observations of the second type report production data from each reservoir separately, but in an ad hoc manner.[11] Because the accuracy of the reports from these wells could not be verified, we elected to remove all such wells from our sample. This reduced the number of individual wells to 16,787, and the number of distinct observations to approximately 2.3 million.

The second set of data issues arise because our data reflect monthly observations. As wells could be completed on any day of the month, and wells are occasionally "shut-in" for maintenance or other issues, the number of days a well might be producing could be smaller than the number of days in that month. Moreover, months have varying numbers of days. Fortunately, the raw data includes information on the number of days that each well was in operation during any given month. Using this variable, we were able to calculate the average daily production in any month a well was in production. We then multiplied this average daily production by 30, which gives us monthly production "as if" the well operated for 30 days per month.[12]

[11] After communicating with the Wyoming Oil and Gas Conservation Commission, we found that the volume of production allocated to each reservoir was determined by the well operator, generally in an ad hoc manner – typically, via a time-invariant apportionment.

[12] One might wonder if the number of days a well is operated in a given month is endogenously chosen. To the extent this is a valid concern, monthly production patterns could be significantly different from average daily production patterns. We investigated this possibility, and found that the two sets of results were broadly similar; these results are available from the authors upon request.

The nature of decline-curve analysis requires that we estimate decline rates from the peak production rate going forward (Kasim and Kemp, 2005; Cronquist, 2001). While the peak production rate often occurs in the first month of production, this is not always the case. Figure 5 displays a histogram of operating months in which peak production occurred for wells in the dataset. The figure shows the majority of wells reach peak production early in their operating life. However, some natural gas wells take several years to reach peak production. A concern is that the observed behavior of these wells could result from some sort of intervention undertaken later in the wells life, such as a re-fracking or re-completion of the well. If so, the well would not be an appropriate candidates for simple decline-curve analysis.[13]

We drop production observations before peak production for those wells with peak production occurring after initial production, in order to make our decline estimates using the full sample of wells. Our estimation strategy requires that wells in the estimation sample have operated for at least 36 months, so wells with fewer than 36 months of operation time are dropped. As a result, wells completed later than 2012 are dropped from the sample. We also remove any wells that exhibited peak production in the first month of the dataset, since we could not verify that this was in fact the month when the well's production peaked (*i.e.*, there is a concern that such wells could represent left-censored data). The sample obtained after these steps consists of 11,678 wells with more than 400,000 monthly observations in the first three months of production.

[13] See Cronquist (2001) for discussion. As discussed below, as a robustness check we present estimation results both including and excluding wells that reached their peak production in a month other than their first operating month.

Table 1 offers some insights into natural gas drilling in the state of Wyoming. Here we tabulate, for each year after 1998, the number of new wells drilled, by county, for the eight counties with the largest amount of drilling. These data reveal that the lion's share of new drilling since the turn of the century has been located in counties 7, 35 and 37. Indeed, during this period more new wells have been drilled in county 35 (Sublette county) than every other county in Wyoming, often by a factor of two or more. This remark is important, as hydraulic fracturing and directional drilling have been commonly employed drilling techniques in this county since the turn of the century. This is a manifestation of the impact of new technology on the array of available drilling prospects.

We augment the production data with information on natural gas spot and futures prices. The price data we use are monthly prices from the Henry Hub. This price is the natural gas benchmark price for the United States. We chose to use this price, rather than the Opal Hub price, which is the benchmark for Wyoming natural gas, to avoid endogeneity. We do not expect a endogeneity problem when using the Henry Hub prices, because production observations occur at the well level, and any individual well in Wyoming is not large enough to affect the Henry Hub price. However, as a robustness check, we ran the regression using the Opal Hub price, and got very similar results.[14] We use spot prices in our estimation of equations (3) and (4). The availability of Henry Hub spot prices from the Energy Information administration begins in 1997, so this further limits our sample to wells drilled in 1997 or later for those regressions, which reduces the sample size to approximately 10,500 individual wells with approximately 350,000 individual monthly production observations.

[14] Results available upon request.

Henry Hub futures prices are available beginning in 1994, so our price-elasticity of drilling regressions with futures prices include samples with wells drilled as early as 1994. The price elasticity of drilling samples are monthly time-series with 216 observations with spot prices, and 252 observations with futures prices.

3.5 Results

We now turn to a discussion of our empirical results. These results fall into three categories: (1) the effect of prices on intra-well production and trends in intra-well production, (2) the effect of prices on peak-production rates and trends in peak-production rates, and (3) the price-elasticity of drilling rates.

3.5.1 Intra-Well Production Results

One should expect well-level production rates to exhibit idiosyncratic effects related to geological characteristics and characteristics of the well operator. We therefore employed a fixed effects regression – based on equation (3). The results from this regression are contained in Table 2, which lists the point estimate and robust standard error, clustered at the well level, for the coefficients on the various regressors. We report results for six samples. The first set of results, shown in column (1), includes all observations from the estimation sample described in the last section. The second through fifth sets of results, shown in column (2) to (5), include results from quartiles of well size as defined by peak production rate. Column (2) reports results from a sample of only the smallest 25% of wells

based on peak production rate, column (3) reports results from a sample of the next largest 25% of wells based on peak production rate, column (4) reports results from a sample of the third largest 25% of wells based on peak production rate, and column (5) reports results from a sample with only the largest 25% of wells based on peak production rate. Column (6) reports results from only wells that reached their peak-production rate in their initial production month.

The goodness-of-fit of our model, as measured by the within-well R^2, increases when the sample includes larger and larger wells. The sample with only wells with simultaneous initial and peak production exhibited the highest R^2, which is consistent with the assumptions of decline-curve analysis, i.e., peak production and initial production occur simultaneously (Cronquist, 2001). The fact that statistically significant coefficients are broadly consistent across all six samples indicates the model is well specified.

The estimated coefficient on the spot price variable, $\ln(p_t)$, indicates a price elasticity of supply of just .026 at the well level for the full sample, so a 10% increase in the Henry Hub spot price is associated with a just 0.3% increase in production within an individual well.[15] This result reinforces previous empirical and theoretical work showing that prices have a very mild effect on within-well production rates (Arora, 2014; Kellogg, 2014). It also buttresses the petroleum-engineering approach to estimating intra-well production. Producers in our sample do not appear to be adjusting production from wells after drilling in an economically significant way. The indication is that production from pre-drilled wells does

[15] We chose to use spot prices in the estimation of (3) and (4) because changes in intra-well production should respond to current prevailing price levels. We use spot prices and futures prices when we estimate (5) because drilling decisions are more likely to take futures prices into account.

not appear to be an important margin on which economic decisions are made. The magnitude and statistical significance of these price elasticity estimates does very by sample as indicated in Table 2, but all of the estimated point to very low responsiveness to price. However, producers will take expected well-level productivity into account when making drilling decisions, which motivates the following discussion of decline-related productivity.

Our analysis reveals an important tendency for the rate of production to decline as the production life of wells increases. Using the full estimation sample, the estimated monthly rate of decline is roughly 7% per month in the first-year of production, 5% per month in the second year of production, and less than 4% per month in the third year of production. All of these estimates are statistically significant at the 0.1% level. The decrease in these estimated decline rates indicates that natural gas wells in our sample exhibit hyperbolic decline. The regression was also run allowing for the decline rate to continue to decrease in the fourth year by including $D4_i m_i$. The coefficient for this variable was positive and statistically significant, but economically insignificant, and did not affect the other estimated coefficients. We preferred the estimation without $D4_i m_i$ and larger production year dummy variables, because these variables become increasingly less significant, and there exclusion allows for a larger sample with more recently drilled natural gas wells. Results from regressions including dummy variables up to the seventh year of production, i.e., up to $D7_i m_i$, are available upon request. This tendency toward a lower and stable decline rate is consistent with the assertion that hyperbolic natural gas wells eventually reach a steady-state, or asymptotic rate of decline (Kasim and Kemp, 2005; Cronquist, 2001).

The tendency for production to decline over time is more pronounced in more recent years: the coefficients on the interaction terms between time and the year a well was drilled are negative and statistically significant for 2007 through 2012 for five of the six samples. The only exception is the third column coefficient for 2012. The coefficients on the $Dl_i m_i$ variables indicate decline rates are increasing over time. The net effect of technological changes since 2000 has been to decrease well level productivity as measured by the decline rate.[16] Production from newer wells tends to decline more rapidly relative to wells drilled before 2000. We also note that these decreases in productivity appear to be increasing in magnitude over time. Production from the average wells drilled in 2009, 2010, and 2011 declines almost 1% faster per month than wells drilled before 2000, and wells drilled in 2012 decline more that 1% faster per month. This effect implies a decrease in second year production of approximately 70 MMcf for a typical well drilled in 2009, 2010, or 2011 relative to wells drilled before 2000, which corresponds to a revenue decrease of approximately $200,000 for a natural gas price of $3.00 per Mcf.[17]

The estimated coefficient on $H_i m_i$, the indicator of horizontal drilling direction, is statistically insignificant at conventional levels, implying that horizontal drilling does not have a statistically important effect on decline productivity. This lack of significance is likely the result of the relatively low proportion of horizontally drilled wells in the estimation data sample (they made up just 0.5% of the estimation dataset). By contrast, the coefficient on $D_i m_i$ is statistically significant: directional drilling increases the decline rate by

[16] See Figure 1

[17] Natural gas prices are generally based on energy content, and are quote in $/MMBTU. A commonly used rule-of-thumb in natural gas markets is 1 Mcf of natural gas contains 1 MMBTU of energy.

approximately 0.5% per month.

3.5.2 Peak-Production Results

We now turn to a discussion of the results of our estimation of equation (4), which measures the influence of time-invariant factors on initial production rates, where variation in peak-production rates are measured by the fixed effects estimated in (3). In Table 3, we list estimates of the effects of drilling years relative to pre-2000 on peak-production rates, the effects of drilling directions relative to vertical drilling on peak-production rates, and the effect of the natural gas price in the peak-production month on peak-production rates.

We report four regressions. In the first regression with results listed in the first column of Table 3, we include only year dummy variables; these results seemingly point to large increases in peak production on an annual basis throughout the 2000's relative to wells drilled before 2000. In the second specification, we add the spot price variable. The results indicate a statistically-significant price elasticity of peak production of 0.51. Further, peak production rates are smaller between 2002 to 2006 than peak production rates before 2000, and larger between 2008 and 2012, when prices alone are controlled for. In the third specification we add controls for drilling direction. After controlling for drilling direction, peak-production rates no longer show any tendency toward increase after the turn of the century, and peak production rates are substantially lower between 2002 and 2007 than peak production rates before the turn of the century. Finally, in the fourth specification we present the full estimation of (4). After controlling for drilling direction, operator-specific

effects, and formation-specific effects, we see that peak production rates are actually decreasing in price with an elasticity of -0.12, so a 10% increase in price is associated with a 1.2% decrease in peak production rates.[18] This negative elasticity represents the increase (decrease) in profitable drilling prospects associated with increases (decreases) in natural gas prices, i.e., less productive wells become profitable when natural gas prices increase, so the average productivity of new wells is lower during periods of high prices. The apparent increase in peak-production rates indicated in column (1) of Table 3 resulted from producers drilling into unconventional reservoirs with new technology. The negative price elasticity of peak production indicates the net effect of employing more inputs to increase production and moving toward less productive wells when prices increase is a decrease in average initial production.

The results in Table 3 indicate that horizontal and directional drilling have both tended to increase peak-production rates even with operator and formation control variables. This indicates that horizontal and directional wells are more productive even for the least productive firms and formations. So, we have found that new technologies have tended to increase peak-production related productivity, while decreasing decline-rate related productivity. We have also found that prices have very little impact on production from previously drilled wells, and on are inversely related to peak-production rates. These price elasticity estimates strongly support the petroleum-engineering view of well-level natural production, and imply that the key margin on which economic decisions are likely to be

[18] To facilitate expositional clarity we do not report the large number of estimated parameters associated with formation- and operator-specific effects here. These estimates are available upon request.

made is the rate at which new wells are drilled.

3.6 Drilling Results

The results of our estimation of (5) are presented in Table 4. The first five columns in Table 4 represent our use of five different price series in the estimation of (5). The first column shows our estimated price elasticity of drilling with the Henry Hub spot price series. The estimated elasticity is 0.61, so if the Henry Hub spot price increases by 10% our results indicate new wells will increase by 6.1%. The second through fifth columns of Table 4 show our estimates using futures prices. Column (2) shows the estimated price elasticity of drilling with respect to the one-month futures price, or prompt-month price, while columns (3) to (5) show the estimated elasticity with two-month, three-month, and four-month futures, respectively. The magnitude of the elasticity estimates and the R^2 increase when longer-dated futures are used in the estimation, indicating producers react more strongly to futures prices in their drilling decisions. The price-elasticity of drilling with respect to the four-month futures price is 0.73, so if the four-month futures price increases by 10%, then drilling rates increase by 7.3%.[19] The higher responsiveness to futures prices makes sense, as the decision to drill in the current period implies natural gas production long into the future. These results imply that the most important margin on which natural gas producers respond to natural gas price changes is through drilling rates.

There are potential problems related to spurious results associated with non-stationarity,

[19] We also estimated all five specifications of (5) using real price series deflated using the Producer Price Index. The results with the real price series were consistent with the results presented here and are available upon request.

and endogeneity in the estimation of (5). While we do not expect well-level production rates to affect Henry Hub prices, it is possible that a large increase in new wells in Wyoming could lead to decreases in the Henry Hub price. Further, if any of the series are non-stationary, then the model may produce spurious results. In order to check the robustness of our estimates, we use Johansen's procedure to analyze possibility of a cointegrating relationship that is robust to non-stationarity and endogeneity (Johansen, 1991). The Johansen procedure indicated the existence of a cointegrating vector between the natural log of new well counts in our sample, and the natural log of the four-month futures Henry Hub price series. The estimated elasticity using this procedure was statistically significant 0.82, which indicates an 8.2% increase in drilling for each 10% increase in price. This elasticity estimate is near the upper bound of the confidence interval for the analogous estimate using simple OLS, so simple OLS may be slightly underestimating drilling elasticities. In any case, we believe that the drilling results strongly suggest that drilling new wells is the most important margin on which natural gas producers respond to price changes.[20]

Finally, we mentioned above that the price-elasticity of drilling should be expected to vary with well-level productivity. In the previous two results sections, we saw that new technology has tended to increase both decline rates and initial production rates. The latter represents a decrease in well level productivity, while former represents a decrease in well level productivity. These changes in productivity may have caused the price-elasticity of drilling to change over our sample. To check, we used a Wald test to test for a single unknown break point in our estimation of (5) using the four-month futures price series.

[20] The results of our analysis using the Johansen procedure are available upon request.

This test indicated a statistically significant break in the regression in the summer of 2003, which is consistent with the increased use of directional drilling that began to take off in 2003, as indicted by Figure 3. We then re-estimated (5) on subsamples before and after this structural break using the four-month futures price. The estimated elasticity before the structural break is 0.44, while the estimated elasticity after the structural break is 0.65. Indicating a significant increase in the price-elasticity of drilling since the widespread use of new technologies began. These results are presented in the sixth and seventh columns of Table 4. These results indicate that producers in Wyoming were more responsive to price changes after the use of new technologies began to increase.

4 Conclusion

The results summarized in the previous section strongly indicate that intra-well natural gas production levels are dictated by the geological characteristics of the underlying reservoir, rather than being influenced by economic incentives related to prices. If producers could increase production from an individual well by varying inputs used in the production process, we would expect well-level production to respond to price: producers would invest more in inputs to increase production when prices increased. However, we find that well-level production is unresponsive to price during the producing life of the well after drilling occurs, and peak-production rates actually decrease when prices increase, as producers develop less productive drilling prospects. These results support the petroleum-engineering view that well-level productivity is dictated by exogenous geological characterisitics, rather

than endogenous economic decisions based on market signals.

If intra-well production rates are exogenously dictated by the underlying geological characteristics of natural gas reservoirs then the only margin on which producers can respond to price changes is through drilling rates. Our estimates of the price-elasticity of drilling indicate that producers do indeed respond to price changes on the drilling margin. Further, the price-elasticity of drilling is unlikely to be stable over time, because it depends on the productivity of potential wells.

We showed how new technologies changed the well-level productivity in our sample in two distinct ways: new technologies increased decline rate, so production from wells drilled using new technologies tends to decline at a higher rate, and new technologies tend to increase peak-production rates. These productivity changes impacted the price-elasticity of drilling – we found the price elasticity of drilling increased precisely when the use of new technologies began increasing.

In addition to providing an empirical analysis of the price elasticity of supply at different margins in natural gas production, and an objective appraisal of inter-well productivity trends for natural gas wells in Wyoming, this analysis highlights the importance of focusing on margins on which economic decisions can be made in an analysis of the price elasticity of supply. It also points to the possibility of changing price elasticity of supply associated with changes in the marginal productivity of the atomistic units of production in any market. Thus, estimates of the price elasticity of supply on the margin of economic decision for any commodity must be viewed as being associated with a given level of productivity.

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Table 1: Annual drilling, selected Wyoming counties.

	county							
year	7	13	23	25	29	35	37	41
1989	2194	3404	4047	2964	655	9492	19589	3432
1990	1330	1872	3413	823	293	8677	12962	1064
1991	990	1705	7043	—	286	2468	10935	1610
1992	959	761	13178	—	272	3390	18313	4911
1993	5538	1342	21017	171	766	11464	21962	6196
1994	13382	4451	19483	360	642	15890	25590	4727
1995	7945	3948	8723	1854	1603	7317	16201	883
1996	6043	1201	6151	2014	621	6189	12719	591
1997	7029	2920	14108	2584	577	12174	16867	1405
1998	11088	4824	13342	2892	228	12731	17950	1106
1999	6161	7837	6348	3904	686	14332	9238	1285
2000	13951	6336	5602	3745	733	18638	13075	1301
2001	7567	12510	5520	923	444	26051	22974	1060
2002	8860	3790	2373	1057	197	19004	19932	649
2003	9096	7355	3324	4710	256	22425	19676	279
2004	8715	10963	6767	6289	735	26162	18046	989
2005	14255	11694	8277	2679	1170	29544	17605	512
2006	16513	5963	8154	504	994	42225	18627	713
2007	11786	5042	7753	982	269	38158	15856	646
2008	15012	2456	6249	794	—	40979	15216	277
2009	6840	1888	1051	721	101	31136	6820	320
2010	3189	1940	—	52	—	24443	11859	475
2011	2601	989	181	—	194	19171	7944	478
2012	840	128	129	—	102	7090	4438	96

county codes:

7: Carbon
13: Fremont
23: Lincoln
25: Natrona
29: Park
35: Sublette
35: Sublette
37: Sweetwater
41: Uinta

Table 2: Natural log of monthly production rate.

	(1) Full Sample	(2) First Quartile	(3) Second Quartile	(4) Third Quartile	(5) Fourth Quartile	(6) Initial = Peak
m	-0.0751***	-0.0666***	-0.0708***	-0.0764***	-0.0863***	-0.0807***
	(-94.21)	(-36.93)	(-46.95)	(-47.07)	(-56.02)	(-69.20)
Dtyr2	0.0231***	0.0216***	0.0218***	0.0212***	0.0266***	0.0235***
	(62.78)	(21.93)	(27.59)	(32.69)	(43.72)	(50.92)
Dtyr3	0.0358***	0.0332***	0.0339***	0.0335***	0.0410***	0.0374***
	(81.86)	(28.30)	(36.53)	(43.59)	(55.69)	(68.47)
Dct00	-0.00142	-0.00226	0.00107	-0.00190	0.000513	0.00195
	(-1.14)	(-0.76)	(0.46)	(-0.75)	(0.24)	(1.08)
Dct01	-0.00176	-0.00385	-0.00492*	0.000575	0.00308	-0.0000240
	(-1.72)	(-1.81)	(-2.49)	(0.26)	(1.64)	(-0.02)
Dct02	-0.00345**	-0.00651*	-0.00224	-0.00628	0.00102	-0.00109
	(-2.74)	(-2.04)	(-1.07)	(-1.81)	(0.56)	(-0.47)
Dct03	-0.00608***	-0.00538*	-0.00698***	-0.00792**	-0.00236	-0.00424*
	(-5.23)	(-2.09)	(-3.50)	(-2.85)	(-1.26)	(-2.30)
Dct04	-0.00807***	-0.00867***	-0.0124***	-0.00570*	-0.00474*	-0.00320*
	(-7.25)	(-3.77)	(-5.06)	(-2.40)	(-2.51)	(-2.11)
Dct05	-0.00512***	-0.00817***	-0.00816***	-0.00231	-0.00225	-0.00261
	(-5.16)	(-3.73)	(-3.96)	(-1.17)	(-1.30)	(-1.73)
Dct06	-0.00170	-0.00259	-0.00470**	0.00188	-0.00140	0.000536
	(-1.85)	(-1.24)	(-2.68)	(1.06)	(-0.78)	(0.42)
Dct07	-0.00273**	-0.00387	-0.00337	0.0000959	-0.00275	-0.00122
	(-2.94)	(-1.66)	(-1.95)	(0.05)	(-1.61)	(-0.91)
Dct08	-0.00559***	0.00137	-0.00647***	-0.00495**	-0.00614***	-0.00321*
	(-6.39)	(0.71)	(-3.77)	(-2.72)	(-3.89)	(-2.48)
Dct09	-0.00727***	-0.00442	-0.00672**	-0.00646***	-0.00620***	-0.00459***
	(-7.72)	(-1.31)	(-2.95)	(-3.50)	(-3.91)	(-3.39)
Dct10	-0.00850***	-0.00713*	-0.0122***	-0.00685***	-0.00886***	-0.00561***
	(-8.55)	(-2.32)	(-4.82)	(-3.87)	(-5.34)	(-3.74)
Dct11	-0.00762***	-0.00161	-0.00637**	-0.00671***	-0.00913***	-0.00593***
	(-8.17)	(-0.59)	(-2.83)	(-3.69)	(-5.76)	(-4.47)
Dct12	-0.0114***	0.0101***	0	-0.00624*	-0.0131***	-0.00655*
	(-4.31)	(5.83)	(.)	(-2.02)	(-4.58)	(-2.35)
dHt	0.000341	-0.00852	-0.00476	0.00573	0.0103*	-0.000835
	(0.15)	(-1.58)	(-1.22)	(1.66)	(2.38)	(-0.28)
dDt	-0.00429***	-0.00233	-0.000516	-0.000957	-0.00378***	-0.00532***
	(-9.08)	(-1.47)	(-0.40)	(-1.14)	(-4.89)	(-7.48)
ln_hh	0.0262***	-0.0170	-0.00931	0.0311*	0.0646***	0.0155*
	(4.04)	(-1.06)	(-0.70)	(2.40)	(6.21)	(2.03)
within R^2	0.40	0.27	0.35	0.44	0.49	0.53
N	348405	64116	83630	95144	105537	140979

t statistics in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 3: Explaining first-month productivity.

	(1)	(2)	(3)	(4)
	FE	*FE*	*FE*	*FE*
D00	0.207**	0.0515	0.0690	0.0349
	(3.11)	(0.75)	(1.04)	(0.66)
D01	0.165**	-0.0205	0.0123	-0.0153
	(2.80)	(-0.33)	(0.20)	(-0.31)
D02	-0.0240	-0.301***	-0.264***	-0.0968
	(-0.37)	(-4.09)	(-3.71)	(-1.68)
D03	0.0504	-0.312***	-0.336***	-0.173**
	(0.85)	(-4.23)	(-4.71)	(-3.00)
D04	0.0106	-0.386***	-0.474***	-0.205***
	(0.20)	(-5.36)	(-6.79)	(-3.64)
D05	0.0513	-0.373***	-0.497***	-0.259***
	(1.01)	(-5.18)	(-7.12)	(-4.59)
D06	0.224***	-0.134*	-0.273***	-0.210***
	(4.69)	(-2.09)	(-4.38)	(-4.17)
D07	0.298***	0.0169	-0.149**	-0.235***
	(6.20)	(0.29)	(-2.61)	(-5.07)
D08	0.399***	0.222***	-0.0574	-0.281***
	(8.52)	(4.32)	(-1.13)	(-6.76)
D09	0.631***	0.533***	0.118*	-0.304***
	(12.13)	(10.03)	(2.20)	(-6.93)
D10	0.545***	0.486***	0.00116	-0.395***
	(10.62)	(9.41)	(0.02)	(-9.11)
D11	0.665***	0.602***	0.0656	-0.408***
	(12.58)	(11.32)	(1.19)	(-9.04)
D12	1.074***	1.006***	0.386	-0.405
	(3.82)	(3.59)	(1.42)	(-1.93)
ln_hh		0.511***	0.474***	-0.118*
		(8.32)	(7.96)	(-2.42)
Dh			0.241	0.566***
			(1.57)	(4.51)
Dd			0.729***	0.251***
			(26.48)	(10.22)
_cons	-0.336***	-0.911***	-0.974***	-0.510***
	(-12.64)	(-12.30)	(-13.57)	(-4.07)
N	10564	10564	10564	10564

t statistics in parentheses

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 4: Explaining drilling rates.

	(1) Spot	(2) Prompt	(3) 2 Month	(4) 3 Month	(5) 4 Month	(6) 4 Month Early	(7) 4 Month Late
ln_hh	0.608***						
	(12.73)						
ln_hh1		0.680***					
		(14.60)					
ln_hh2			0.703***				
			(15.54)				
ln_hh3				0.719***			
				(16.43)			
ln_hh4					0.731***	0.450***	0.645***
					(17.15)	(4.46)	(10.30)
_cons	3.109***	2.968***	2.923***	2.890***	2.868***	3.08***	3.08***
	(43.12)	(44.30)	(44.34)	(44.83)	(45.43)	(28.61)	(28.01)
R^2	0.43	0.46	0.49	0.52	0.54	0.15	0.44
N	216	252	252	252	252	115	136

t statistics in parentheses

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Figure 1: The effect of a decline rate shock on the production profile of a gas well.

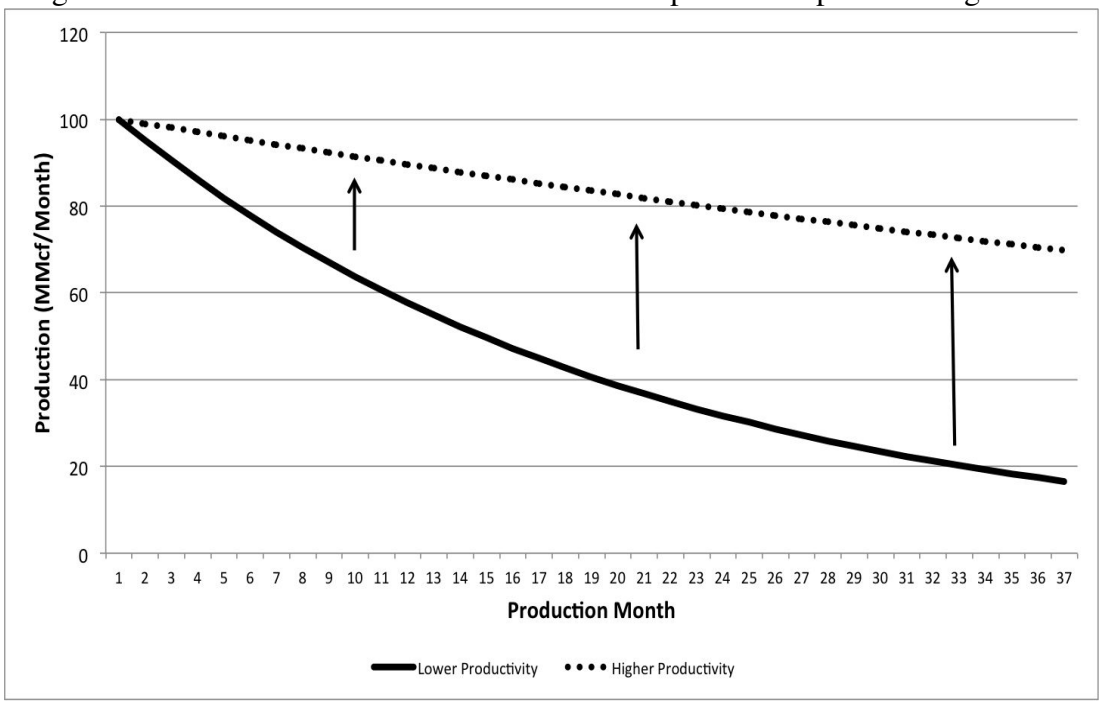

Figure 2: The effect of an initial production shock on the production profile of a gas well.

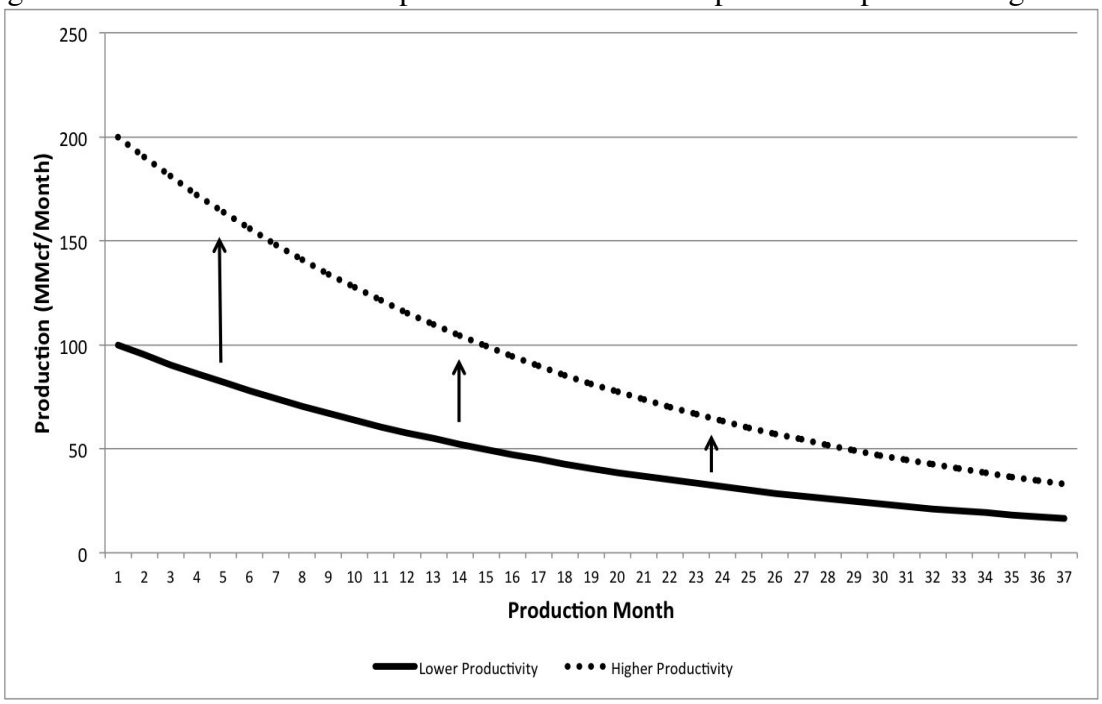

Figure 3: Wells drilled by direction by year.

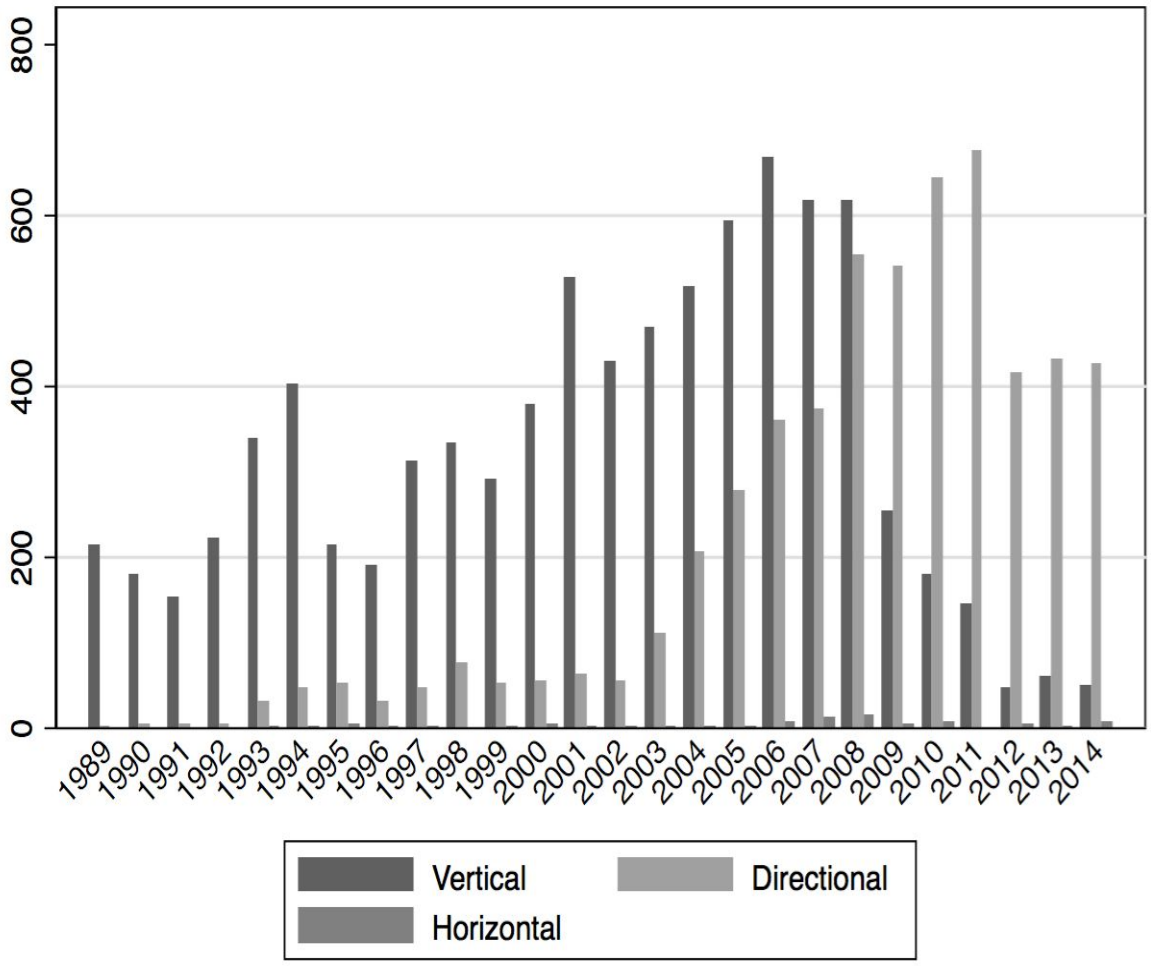

Figure 4: Natural gas production from Wyoming's largest fields.

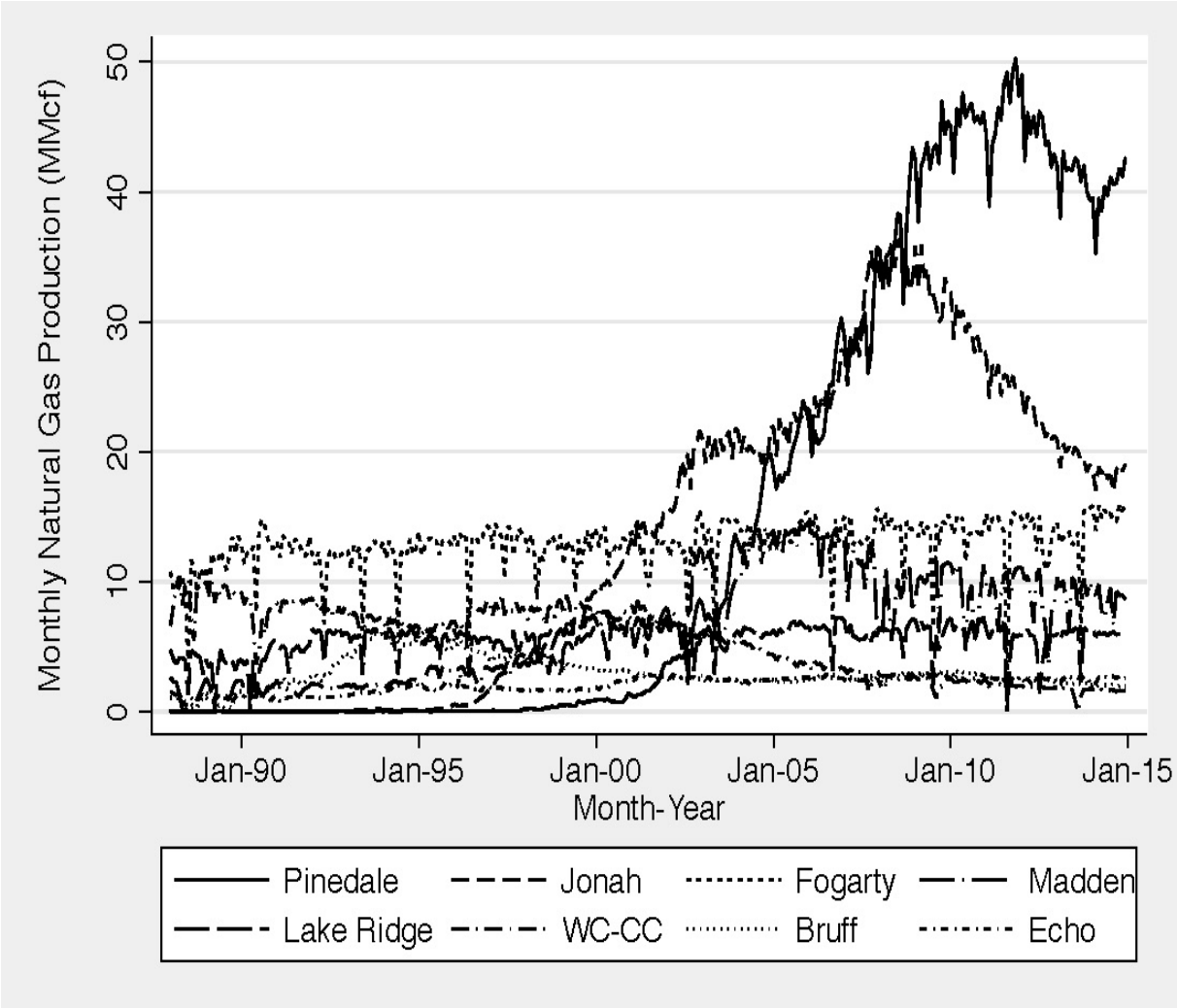

Figure 5: Histogram of number of months before peak production reached.

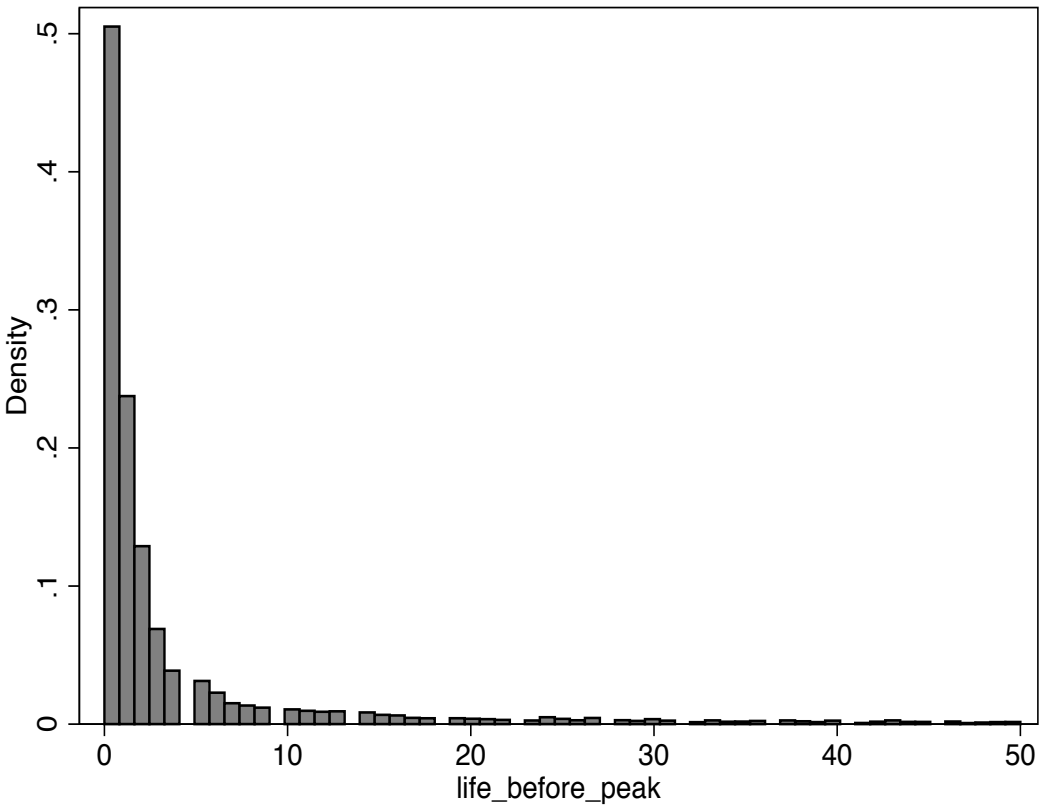

Figure 6: Production relative to pre-2000 estimates by drilling year (2000 to 2006).

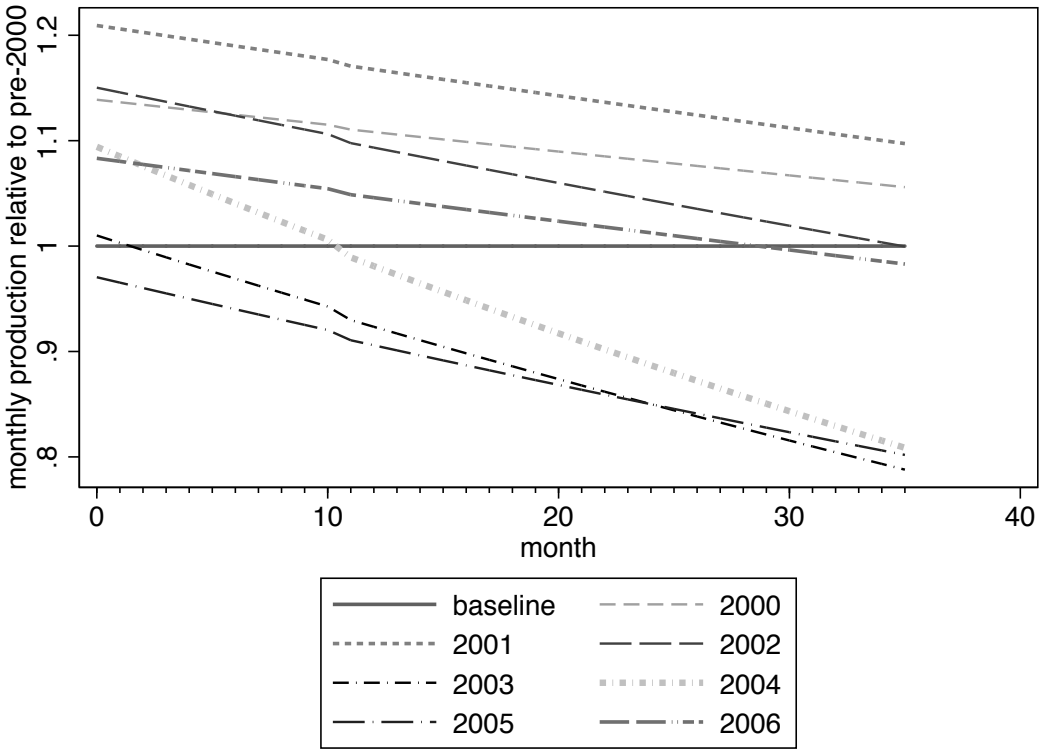

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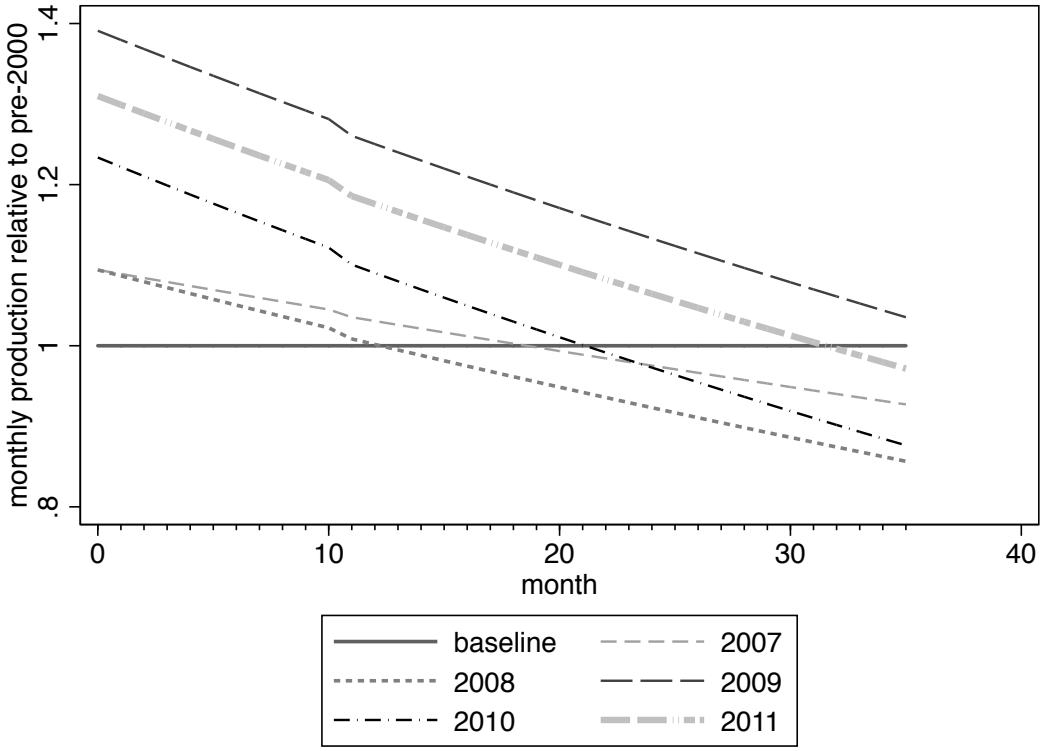
Figure 7: Production relative to pre-2000 estimates by drilling year (2007 to 2011).



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