The Option to Hold a Petroleum Lease by Production:

A User's Guide to the Shale Gas Drilling Boom

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Abstract

Most oil and gas leases allow the operator to extend possession for an indefinite period by establishing production in paying quantities. We show how this option to "hold by production" (HBP) stimulates the drilling of many wells that would otherwise be uneconomic. Although such wells may superficially appear to be poor investments, in fact they contribute to shareholder value. We also show, however, that the HBP provision delays the drilling of other economic wells, an outcome that has become a frequent point of conflict between lessees and lessors in this industry. We provide a simple method to value the HBP lease provision as a compound option, and estimate that it has increased the value of typical shale gas leases in the U.S. by 25%-250% in recent years, depending on location. The HBP provision appears very likely to have increased drilling in certain areas, but even more likely to have decreased drilling elsewhere. Understanding the incentives created by the HBP option is fundamental to understanding the rate and pattern of drilling in U.S. shale gas plays. Our analysis does not support industry critics who allege that continued drilling of many sub-marginal gas wells has been a mistake.

JEL Codes: D86, G13, Q33, Q35

Key words: real options, shale gas, compound options, petroleum leasing, resource valuation

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The recent shale boom has revived private investment, as well as public interest, in the U.S. petroleum industry. Development of horizontal drilling techniques and application of controlled fracturing to thin layers of sedimentary rock have converted vast uneconomic resource deposits into valuable and productive reserves. Domestic oil and gas prices have fallen in consequence, and projected volumes of oil and gas imports to the U.S. have been sharply reduced, or even negated, as domestic production has increased rapidly toward levels that might support U.S. exports to the rest of the world.

But these developments have been accompanied by doubts whether the "boom" is sustainable in the long term. One major concern is that a significant portion of current shale gas production seems to come from wells that are under water and will never pay out. Indeed, Sandrea (2014) contends that it is conventional wisdom that most shale gas wells are out of the money. The boom itself is partly to blame for this, since the unexpected surge in production pushed gas prices below the breakeven level required by many wells. What may require further explanation is why the industry has continued, as some allege, to drill many new gas wells that are uneconomic. Berman (2011), for example, recognizes that unexpected price weakness has contributed to losses, but suggests that some companies have consciously destroyed shareholder value by continuing to produce large volumes of gas into a low-price market. Similar sentiments have been expressed by the iconic T. Boone Pickens, whose advice to the gas industry is simple: "Quit drilling. Shut her down. We are stupid to drill these wells."[1]

There has been speculation in the media about why overdrilling occurs—assuming that it does—but the analysis is not very deep. For example, the *New York Times* reports as follows: "After paying bonuses of up to $20,000 an acre to the landowners, the companies could not afford to lose the leases, even if the low price of natural gas meant that drilling more wells was a losing proposition."[2] Economists who understand that sunk costs should not affect operating decisions may wonder why the cost of the lease should play any role, and require stronger evidence that the industry has been guilty of throwing good money after bad. In other quarters, overdrilling is viewed as predatory behavior by certain large gas producers who have deliberately overproduced to depress the price and force smaller rivals out of the business.[3] But, the U.S. gas production business is not heavily concentrated and barriers

[1] Quoted by Krauss and Lipton (2012).
[2] Krauss and Lipton (2012).
[3] Adams (2013).

to entry are low, so it is not clear what lasting benefits the alleged perpetrators could hope to achieve from this scheme.[4]

The theory of real options provides a different explanation for the appearance of overdrilling, but one that has not yet received close examination. Its relevance stems from the operator's incentive to retain leased property for future use, which for most leases requires the drilling of at least one well during the relatively short primary term of the lease. From this perspective, the loss incurred by drilling a sub-economic well before the lease expires can be regarded as the price of exercising an option to extend the term, which creates a further option to resume drilling and exploitation later if and when market conditions improve. But for the drilling of that one well during the primary term, the entire lease and all further options would be relinquished. What may be surprising, is that the same considerations that sometimes lead to the drilling of a sub-marginal well will, under different circumstances, actually suppress the drilling of supra-marginal wells. As we explain below, this is not due to a shortage of drilling rigs or lack of capital. It does not presume that sub-marginal wells substitute for supra-marginal wells. Rather, it reflects the operator's judgment that delay, facilitated by the hold-by-production (HBP) provision, is profitable.

Although it seems clear that operators have drilled many gas wells to hold their leases,[5] this does not necessarily imply an increase in the overall number of wells. The structure of the option to hold by production will sometimes compel the operator to *limit* the number of wells drilled during the primary term of the lease. To see why, we view the lease as a bundle of interdependent options. If the lease is in the money, the operator might exercise the option to fully develop the lease during the primary term (which typically requires several wells). Alternatively, he may exercise the option to extend the lease term (by drilling a single well), which then creates a third option to further develop the lease in future years as conditions dictate. Thus, the HBP provision may encourage the drilling of sub-marginal wells on certain tracts but delay the drilling of supra-marginal wells on other tracts. The latter

[4] Total 2013 gas production by the fifty largest U.S. petroleum companies (ranked by combined oil and gas reserves) tabulated by Ernst & Young (2014) amounts to only 55% of total U.S. gas production, as reported by the U.S. Energy Information Administration. Foreign producers plus many small U.S. companies make up the difference. Because the U.S. natural gas market is to some extent geographically fragmented, certain regions exhibit higher concentration and less liquidity, as documented in FERC (2003). Despite close examination of trading behavior in those regions, however, the FERC study finds no evidence of market manipulation.

[5] Starnes (2009) quotes a prominent energy investment banker: "I don't think there's any doubt companies are drilling Haynesville and Marcellus wells just to hold acreage." Turning further west, Starnes quotes a spokesman for Petrohawk (the independent operator that pioneered the Eagle Ford shale play): "It is absolutely something we're thinking about... it's all about protecting access."

outcome, and by implication the HBP provision itself, has caused frequent conflict and litigation between landowners and operators. It is not clear, however, that landowners would be made better off by excluding the HBP provision since its exclusion would reduce the market value of their leased property by tying the hands of operators. We will examine that tradeoff later in the paper.

To complete our argument, it should be recognized that only in certain circumstances does it make sense for the operator to exercise the HBP option and hold the lease. It would not make sense to drill a sub-marginal well if that well would incur losses that are too large, if the cost of additional development would be too high, or if expected production rates from ensuing wells would be too low. Instead, the lease should be relinquished. Likewise, it would not make sense to refrain from drilling supra-marginal wells on the lease during the primary term if the foregone profits exceed the expected profits from delayed development. Because leased tracts vary in terms of drilling cost, geological potential, and resource recovery factors, the decision to hold leases by production would not be taken uniformly throughout the industry. What makes sense for one lease or in one basin might not make sense for another. To decide in any specific instance, the operator must be able to value the option. The principal contribution of this paper is to formulate this investment decision in terms of nested options, to provide a simple method of valuation, and to demonstrate the influence of major operating parameters on the decision to drill versus relinquish.

Two secondary contributions follow from the first. The potential conflict between landowner and operator is examined and shown to arise from a time-inconsistency problem on the part of the landowner. Landowners will favor a lease form that contains the HBP provision because it maximizes the market value of the lease they have to award, but later may press for rapid development (and abrogation of the HBP provision) to advance their receipt of production royalties. The cost of enforcing the HBP provision is of the essence because we are able to show that, if the HBP provision were enforceable at no cost, the landowner would still favor that form of lease and settle for a potential delay of royalties. Also, based on the heterogeneity of physical characteristics between and within the major shale gas basins in the U.S., we are able to estimate the frequency with which the HBP option will be exercised in specific areas, and to identify in each whether the impact would tend to stimulate or suppress drilling activity. Finally, given the range of realistic economic and operating parameters, we estimate that the value of the HBP option adds anywhere from 25% to 250% to the value of the lease. These results show that, although valuation errors due to the omission of a particular operating option may sometimes be small, as demonstrated by Trigeorgis (1996), the error in valuation from ignoring the HBP option is typically large.

In the Section 2, we review previous applications of real option theory to the petroleum industry. Section 3 describes aspects of resource development that are, along with lease provisions, fundamental determinants of lease values. In Section 4, we formulate and solve the operator's investment problem by linking a pair of risk-neutral binomial lattices that capture the nested structure of options created by the HBP provision. Numerical examples are presented in Section 5 to illustrate how lease values and drilling behavior are influenced by the existence of the HBP option and variations in the principal background parameters (e.g., drilling cost, well spacing, resource potential, and primary term). The conflict between landowner and operator is explored in Section 6. In Section 7, we show how the importance and impact of the HBP option varies across and within the major shale gas basins of the U.S. Section 8 concludes.

2. Related Literature

Applications of real option pricing to the petroleum industry began to appear thirty-five years ago. Tourinho (1979) frames the decision to invest in natural resource production as a call option wherein exploration and development expenditures are interpreted as the price of exercising an option to acquire the stream of production. For the case of a perpetual lease with no expiration date, Tourinho obtains analytic solutions for the value of the investment opportunity, as well as the optimal timing rule. Tourinho's analysis lumps all exploration and development costs together, however, and does not consider the possibility of compound or sequential options. Paddock, Siegel, and Smith (1988) tackle this problem under the presumption of a fixed-term lease, provide numerical solutions of the resulting dynamic control problem for a sample of federal oil and gas leases in the Gulf of Mexico, and examine the comparative static effects of price volatility and expiration date on lease value and the timing of investment. Pickles and Smith (1993) apply the binomial lattice approach to investigate lease valuation and optimal investment timing for a sample of fixed-term petroleum leases from the UK sector of the North Sea. The empirical validity of these early approaches has recently been tested by Kellogg (2014), who finds that the timing of investments by Texas drillers tends to fluctuate—as predicted by option theory—with variations in the volatility of the price of the underlying commodity.

Although the first applications of option valuation to the petroleum industry focused on the decision to delay initial investments, extensions to incorporate the compound structure of oil field options soon followed. Bjerksund and Ekern (1990) consider the option to shut down production temporarily, but find that type of flexibility adds very little to the value of reserves, at least for the cases they considered. Laine (1997) considers the option to expand production after initial development and, like us, adapts the binomial lattice approach to handle the additional decision points. Zettl (2002) follows the same approach to estimate the value of the option to abandon or expand operations. Dias (2004) models the expansion option differently than Laine or Zettl, by permitting the operator to "supersize" the initial investment, which creates excess capacity sufficient to facilitate later expansion. Paxson (2007) obtains an approximate analytic solution to value a compound option where the first outlay (setup costs) must be made at a given time, but is followed by the option to complete development any time before the fixed expiration date of the lease. All of these papers deal, like us, with the decision on how investments and production will be staged. Unlike us, however, none of them contemplates the ability to undertake investments that prolong the life of the option.

Mölls and Schild (2011) analyze the impact of optionality on time-to-completion by an operator working to finish a project before a fixed deadline. The operator must complete an investment of fixed total size by a certain date, starting with a pre-determined setup cost, as in Paxson (2007). After that, the investment rate is variable and the operator's pace will determine the time to completion. The authors show that, if the size of the setup cost constitutes a larger fraction of the total investment, the expected time to completion is reduced. The result comes from the fact that a larger setup component reduces the remaining cost required for completion, which effectively moves the project deeper into the money once setup is complete and reduces the incentive to delay. Another application of compound options to the petroleum industry is by Corts (2008), who models the option to maintain idle drilling rigs in good operating condition (as opposed to stacking them) in order to avoid the costs of remobilization. This study is interesting in its own right, but of limited relevance to our work. Brandão, Dyer, and Hahn (2005) show how decision trees may be used instead of binomial trees to value compound options. For investment problems with relatively few decision points, that approach can seem more transparent and intuitive, but for larger problems (like ours) with many decision points, the computational burden grows rapidly.

Jones and McDowell (2009) review the relevant legal aspects that might limit an operator's right to hold a petroleum lease through and past the primary term. Although many States recognize an "implied covenant" to continue development once it has begun, this does not appear to prevent the operator from delaying investment for a reasonable period of time. In contrast, individual landowners may sometimes place in the lease an “express covenant” that compels expeditious development, but the results are unpredictable and often left to the judgment of the courts. These distinctions between lease provisions that potentially limit the operator’s options, and their impact on the value of the lease, are examined later in our analysis.

Outside the U.S., relinquishment of the lease is not necessarily an all-or-nothing affair. In Norway, for example, the operator may be required to relinquish fractional portions of a lease upon reaching the end of the primary term, even if production has been established (Norwegian blocks are much larger than in the U.S.). This forces a decision on the operator that Hamacher and Jörnsten (2010) formulate as a combinatorial optimization problem based on information regarding future development scenarios. Their analysis, however, does not draw on the theory of real options and is not related to either the volatility of prices or the timing of investment. Finally, we mention the paper by Fitzgerald (2010), who finds that leases held in split-estate (i.e., mineral rights divorced from surface rights) tend to have lower market values, presumably because of the additional costs of negotiating and coordinating among several parties. We abstract from the problem of split-estates in the work that follows, but this effect could be incorporated by making appropriate adjustments to the operator’s cost of development.

3. Lease Provisions and Resource Development

We consider a standard lease that gives the operator (lessee) the right to develop and produce petroleum from a prescribed area. Development requires a fixed expenditure for the drilling of wells and installation of equipment. These expenditures transform the undeveloped acreage into a producing property that taps what the industry calls “estimated ultimate recovery” or EUR. This is an estimate of the volume of resources that will be extracted before the wells are eventually depleted. EUR for a given lease will depend upon the areal extent of the lease, the thickness of the shale bed, and the physical properties of the rock. Development costs depend primarily upon the depth of the shale bed below the surface and the specific nature of the rock, both of which affect the cost of drilling.

Development must commence during the primary term of the lease, which typically extends over several years. If production is not established in “paying quantities” before the primary term expires, the lease must be relinquished and the enterprise is terminated. Otherwise, the operator retains the right to exploit the lease through continued production and further drilling, indefinitely. It is important to understand the meaning of “paying quantities” in this context. Courts have established that it is sufficient for production revenue to cover the variable cost of operating the wells. Revenues sufficient to recover invested capital are not required.[6] It is also important to note that some courts recognize an "implied covenant to develop" that prevents an operator from deferring further development for too long. Although the implied covenant is not treated uniformly in all jurisdictions, the court's decision in *Blake v. Texas Co.* fairly sums up what must be an operator's expectations: "The (operator) cannot forever choose to delay further development and at the same time prevent others from drilling. Should the total time of inactivity measured in years become unconscionable in and of itself, the (landowner) will be entitled to oust the 'dog in the manger.'"[7] The implied covenant to develop therefore puts a finite, albeit variable, limit on the extension provided by the HPB option.[8] In lieu of the implied covenant, some leases contain an "express covenant to continue development" that may require uninterrupted development of the lease. Although there may be ambiguity about what in practice constitutes an interruption, the value of the HBP option would be diminished and possibility eliminated altogether if the express covenant is present and enforced. See Jones and McDowell (2009, pp. 23:22-23:23) for discussion of the litigation surrounding the express covenant.

The HBP provision creates a set of nested options. The operator has the option to commence full development at any time during the primary term, or to simply let the lease expire. But there is also the option to postpone full development by completing a single well (even if that well is sub-marginal). By exercising that option, the operator acquires a further option to postpone full development and extend the term of the lease. Our goal is to value that option, and to see how it affects lease operations.

The value of the lease depends on many other fundamental factors, including the areal extent of the lease and well spacing rules that control drilling density. Spacing rules limit the total number of production wells that may be drilled on the lease. Such rules were originally adopted by state conservation commissions during the 1930s to prevent wasteful drilling practices. Prescribed spacing generally corresponds to the area that can be drained by a single well. For example, if well spacing is 80 acres, then 8 wells would be needed (and permitted to be drilled) to fully develop a section of 640

[6] For elaboration of this point, see Jones and McDowell (2009, pp. 23:6–23:9).
[7] Even weaker interpretations are sometimes allowed, as discussed by Jones and McDowell (2009, p. 23:29).
[8] Some leases contain an "express covenant to continue development," which may require uninterrupted development of the lease. Although there may be ambiguity about what in practice constitutes an interruption, the value of the HBP option is diminished and possibility eliminated altogether if the express covenant is present. See Jones and McDowell (2009, pp. 23:22-23:23). We examine the financial impact of an express covenant to develop later in the paper.

acres.[9] These rules vary widely across and within shale basins in the U.S., ranging between 40 and 320 acres per well depending on the geologic character of local resources.[10]

4. Valuation

We denote the areal extent of the lease by A, measured in acres. If the permitted spacing is given by B (also measured in acres), then the number of wells required to fully develop the lease is N, the integer part of A/B. Letting EUR represent the expected ultimate recovery per well, then the lease is expected to hold a total volume of reserves equal to $N \times EUR$. We assume the primary term of the lease is given by T (years) and that exercising the HBP option provides an extension of E (years).

Capital expenditure required to drill and complete one well is represented by C, which we assume is fixed and known to the operator. C depends primarily upon the depth of the shale bed below the surface and physical properties of the overlying rock.[11] The cost per unit of developed reserves is therefore given by $K = C/EUR$. The unit value of developed reserves is represented by S. This corresponds to the market price of *in situ* reserves, not the wellhead price of the resource as it is extracted. The difference is due to the time value of money, since production of the developed reserve may extend over several decades. There is an active market for producing properties, which provides a basis for observing S.[12] Companies buy and sell billions of dollars' worth of developed petroleum reserves each year and many of these transactions are publicly reported. Each of these transactions represents a purchase of the rights to a future stream of production. S, the current price of one unit of developed reserves, represents the value of the underlying asset that is acquired by exercising the development option.

As in most applications of option valuation to the petroleum industry, we assume the price of developed reserves follows geometric Brownian motion:

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[9] Additional water injection wells and other types of service wells may also be permitted.

[10] Exceptions to spacing rules may be granted to permit the drilling of at least one well on a lease that would otherwise be too small to qualify. A group of small leases may also be "pooled" to form a drilling unit to which normal spacing applies, with production apportioned on the basis of acreage. Where such pooling occurs, all pooled leases are held by production from a well drilled on any one of them. Similarly, any leases that are "unitized" to permit coordinated development by a single operator are held by production from a well drilled on any one of them. In these cases, our analysis of the HBP option would apply to the combined value of all leases that constitute the pool or the unit.

[11] The assumption that reserves and costs are deterministic could be relaxed without altering the nature of our results. An exploration stage could also be added to the decision problem, to precede development, but very little money is spent on exploration in shale basins because the presence and extent of shale deposits is well known.

[12] See Smith (2014) for recent estimates of the value of oil and gas reserves.

(1) $$\frac{dS}{S} = \alpha dt + \sigma dz,$$

where α represents the instantaneous return on the developed reserve and σ is the standard deviation of a standard Wiener process.[13] We perform the valuation from a risk-neutral perspective, which permits the following substitution:

(2) $$\alpha = r - \delta,$$

where r represents the risk-free rate of interest and δ is the convenience yield earned by the owner of a developed reserve.

The continuous-time process for S described above is approximated by a discrete binomial tree consisting of steps of length Δt. Each period the price will either increase with probability p by the factor u, or decrease with probability $1 - p$ by the factor d, where:

(3) $$p = \frac{a-d}{u-d}; \quad a = e^{r\Delta t}; \quad u = e^{\sigma\sqrt{\Delta t}}; \quad d = u^{-1}.$$

The evolution of prices in discrete time is illustrated in Figure 1, where the primary term is for 3 periods. The value of the underlying asset at any node is given by: $S_{ij} = Su^{i+2(1-j)}$, where i denotes the period and $j - 1$ is the number of downward price movements experienced along the way.[14]

We now define two values, which differ only according to whether or not the lease contains the HBP provision.

> $V(t, S_{t,j}; K, \sigma, r, \delta, E)$ represents the value of the option to develop a lease at time t, when the price of the underlying reserve is $S_{t,j}$ with a remaining term to expiration of E years and no HBP provision.
>
> $V^+(t, S_{t,j}; K, \sigma, r, \delta, T, E)$ represents the value of the option to develop a lease at time t, when the price of the underlying reserve is $S_{t,j}$ and $T - t$ years remain of the primary term, with an HBP provision that would extend the primary term by E years, if exercised.

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[13] Price is assumed to follow Geometric Brownian motion, which admits with low probability some very high prices within the finite term of the lease. Alternatively, a mean-reverting process could be applied without altering our analytical framework.

[14] The structure of the lattice and derivation of all parameters are standard, as described by Hull (1997).

Suppressing parameters that remain constant over the life of the lease, these values can be expressed more compactly as:

(4) $$V_{t,j} = V\big(t, S_{t,j}; K, \sigma, r, \delta, E\big)$$

(5) $$V_{t,j}^{+} = V^{+}\big(t, S_{t,j}; K, \sigma, r, \delta, T, E\big).$$

$V_{t,j}$ is the value of a straight call option that would give the operator the right to acquire the developed reserves any time before the fixed expiration date. It can be priced using a standard binomial lattice, as in Cox, Ross, and Rubenstein (1979) or Pickles and Smith (1993). $V_{t,j}^{+}$ refers to a compound option that can be priced using the modified binomial lattice shown in Figure 1.

As usual, valuation proceeds by calculating from right to left, starting at T, the terminal date of the primary term. At time T, as the lease is about to expire with the underlying asset priced at $S_{T,j}$, the operator has three choices: (1) fully develop the lease, which is valued at $N \cdot EUR \cdot \big(S_{T,j} - K\big)$; extend the term by drilling one well, which is valued at $EUR \cdot \big(S_{T,j} - K\big) + (N-1) \cdot \big[p \cdot V_{T+1,j} + (1-p) \cdot V_{T+1,j+1}\big] \cdot e^{-r\Delta t}$; or abandon the lease without development, which earns zero. Thus, the value of the lease at time T is given as a function of the prevailing price:

(6) $$V_{T,j}^{+} = max\big\{N \cdot EUR \cdot \big(S_{T,j} - K\big);\ \big(S_{T,j} - K\big) + (N-1) \cdot \big[p \cdot V_{T+1,j} + (1-p) \cdot V_{T+1,j+1}\big] \cdot e^{-r\Delta t};\ 0\big\}$$

In any prior period $(0 \leq t < T)$, the value of the lease is given by:[15]

(7) $$V_{t<T,j}^{+} = max\big\{N \cdot EUR \cdot \big(S_{t,j} - K\big);\ \big[p \times V_{t+1,j}^{+} + (1-p) \times V_{t+1,j+1}^{+}\big] \times e^{-r\Delta t};\ 0\big\}$$

These calculations are easily completed within a single *Excel* spreadsheet. The terms $\{V_{T+1,1},\ V_{T+1,2},\ \dots V_{T+1,T+2}\}$ are first obtained from an *Excel* Data Table that calls a standard binomial lattice, inserting each possible price that could prevail at period $T+1$ as the starting value of the underlying asset and E as the fixed term to expiration. This establishes the value of the undeveloped portion of the tract at the time of lease extension, which is an input to (6). The calculations in (7) are then performed recursively by inserting the result from (6) into the binomial lattice shown in Figure 1. The two lattices involved in the calculation are linked by the common terms $V_{T+1,j}$, and by the common

[15] We use the fact that the operator gains nothing by drilling a single well to hold the lease in periods prior to the last, so that option is irrelevant in all but period T.

set of background parameters (K, σ, r, δ). The value of the lease at acquisition, which includes the value of the HBP option, is given by $V_{0,1}^{+}$.

When valuing sequential options, Benaroch, Shah, and Jeffrey (2006) question whether the value of the call at the next stage should be treated as additional value of the asset at the present stage (as we do) or as a subsidy to the exercise price. They conclude, generally, that the latter approach is preferred because the former assumes implicitly that the underlying asset of the second stage evolves according to the same stochastic process as the first—which may not be true if exercising the option at the first stage alters the underlying asset. In our case, the underlying asset is unaffected by exercising the option to hold by production, so the issue is moot. The issue would arise, however, if one were considering sequential options in which the first stage involved development of natural gas reserves, and the second involved installing equipment to remove liquids from the gas for the purpose of marketing them separately.

5. Some Illustrations

To gauge the potential importance of the HBP option, we first consider some hypothetical situations that reflect current economic and geologic conditions. The value of gas reserves is estimated by Smith (2014) to be roughly \$1.00 per MCF. Development costs vary considerably across regions, so we consider a range that extends from \$0.50/MCF to \$3.00/MCF. At the low-end of that range, the reserves would be deep in the money, and at the high-end, quite far out. Especially when far out of the money, option value is quite sensitive to the primary term of the lease, which we vary between 1 and 6 years.

We assume the lease covers 640 acres (1 section), and that permitted well spacing varies between 40 and 640 acres. Thus, the maximum number of wells that can be drilled on the lease ranges between 1 and 16. Finally, the EUR is assumed to be 1,000,000 MCF per well. All of these assumed parameter values lie within the range of reported experience in the major U.S. shale gas basins, and any of the hypothetical scenarios we consider might be encountered in practice. General tendencies within specific basins and finer distinctions between them will be examined later, in Section 7.

Other background parameters used in the calculations include the real risk-free discount rate (2%), the convenience yield (1%), and the volatility of the value of gas reserves (50%). Again, these values are meant to be illustrative of current conditions, but the nature and pattern of results are not particularly sensitive to the chosen values. To perform the valuation, the lattice shown in Figure 1 is extended to include 25 periods during the primary term, which gives 24 steps. In the case of the longest lease term considered here (6 years), the length of an individual step corresponds to one calendar quarter.

Table 1 shows how the value of a lease with the HBP option varies with respect to well spacing and lease term. Wide well spacing and a short primary term combine to produce the lowest value. Value increases with closer spacing since more wells can be drilled to tap a larger volume of reserves, but also because the cost of holding the lease is independent of the number of future wells that may be drilled. As expected, the length of the primary term also has a powerful effect on lease value. For example, facing 160-acre spacing, the value of a six-year lease is roughly *four* times the value of a one-year lease, holding all else constant.[16] This suggests that the option to extend the term by exercising the HBP option might be quite valuable. This is confirmed in Table 2, which isolates the value of the HBP provision in particular by showing the ratio of lease values with and without the option to hold by production. Again taking 160-acre spacing to illustrate the principle, the HBP option adds 32% to the value of a three-year lease, and even more (48%) to the value of a one-year lease. All of these results are based on an out-of-the money prospect, for which development cost ($1.50/MCF) exceeds reserve value ($1.00). The fact that the reserves are out-of-the-money raises the importance of lease term and therefore also raises the value of the HBP option. Note that in the case of 640-acre well spacing, the HBP option adds no value to the lease. This is because, after drilling one well to "hold" the lease, the well-spacing regulation precludes the option to drill additional wells on the same lease if and when the market improves. Considering the range of scenarios shown in Table 2, the HBP option adds anywhere from 0% to 83% to the value of the lease.

The hypothetical lease values shown in Table 1 range between $100 and $12,000 per acre, which is consistent with the actual pricing of natural gas leases in the major U.S. shale gas basins. For example, *Petroleum Intelligence Weekly* (2014) reports the national average price of shale gas leases during 2013 as $1,322 per acre. Because lease prices are determined through negotiations between operator and landowner, we should not expect the landowner to appropriate all rents. Accordingly, the full value of each lease likely exceeds its negotiated price which means that the values in Table 1 represent an upper bound on price.

[16] The value of the lease absent the HBP provision is given by $V_{0,1}$ with $E = T$, and is computed using the standard binomial lattice with fixed expiration.

We should expect the significance of the HBP option to increase on leases where reserves are farther out-of-the-money since that is when the ability to extend the primary term is of greatest importance. This effect is confirmed in Table 3, which shows how the value of the lease varies as a function of development cost (holding reserve value constant at $1.00 and well spacing at 160 acres). With development cost of $2.00/MCF, the value of a six-year lease is now more than *seven* times the value of a one-year lease. And, as shown in Table 4, the HBP option adds 91% to the value of the underlying one-year lease. Even in the case of a six-year lease, where the primary term is already "long," the option to extend further via the HBP provision adds 32% to the value of the lease.

We note that the value of the HBP option may be realized in either of two ways: (1) If reserves are out of the money, but not too far out of the money, the operator will drill one sub-marginal well at the end of the primary term to hold the lease; (2) If reserves are in the money, but not too far in the money, the operator will *refrain* from drilling any wells during the primary term, except for a single well drilled just before the lease is set to expire. In either case, the rationale is the same: the operator sacrifices a current return to acquire a larger expected future return. In the first case, the sacrifice is the loss incurred on the sub-marginal well. In the second case, the sacrifice is the foregone return on supra-marginal wells that would have been drilled but for the HBP option. These decisions are illustrated in Figure 2, which plots the operator's investment decision at each node of the binomial lattice for a three-year lease that starts at-the-money ($K = S = \$1.00/MCF$).

The nodes in Figure 2 are labeled as follows: "O" means the operator drills no wells, "X" means the operator drills all wells permitted by well spacing regulations, and "D1" means the operator drills just one well. As expected, although the reserves begin at even money, drilling is delayed until prices have appreciated substantially. The impact of the HBP provision is felt at the white and yellow nodes. At each white node, the operator continues to refrain from drilling, although all wells would have been drilled then but for the HBP provision (without the HBP option, each white cell reverts to "X"). At each yellow node, the operator drills one sub-marginal well, a well that would not be drilled but for the HBP provision (without the HBP option, each yellow node reverts to "O").

Two conclusions emerge from Figure 2. First, the impact of the HBP provision may be felt long before the lease is due to expire. This is because the drilling of supra-marginal wells may be suppressed fairly early in the primary term, depending on how prices evolve. Second, the HBP provision may either raise or lower the number of wells drilled during the primary term. These conclusions apply generally, whether the lease begins in or out of the money. Figure 3 shows the impact of the HBP provision on the operator's drilling decision for a lease that starts way out of the money ($S = \$1/MCF, K = \$3/MCF$). Drilling is more likely to be stimulated than suppressed in geographic areas and at times when reserves are out-of-the-money, and more likely to be suppressed in other areas and/or times when reserves are in-the-money. Thus, depending on the prevalence of "good" and "bad" areas at any point of time, the net effect of the HBP provision may be either to increase or decrease the level of drilling overall. To our knowledge, the dichotomous nature of the impact of the HBP provision has not been noted previously.

The "moneyness" of the lease does impact the probability of observing one or the other type of outcome. Figure 4 shows how the probability of exercising the HBP option develops as the lease approaches the end of its primary term. The two lines shown in Figure 4 correspond to the scenarios shown in Figures 2 and 3, an even-money lease versus one far out of the money. [17] For the even-money lease (blue line), there is a significant probability that drilling will be suppressed beginning several periods before the lease is due to expire. I.e., supra-marginal wells that would have been drilled but for the HBP provision are sacrificed. By the last period, this occurs with probability of 65%. For the out-of-money lease (red line), there is no perceptible impact on the probability of drilling until the last period, when the probability of drilling a sub-marginal well rises to 21%. Because the lease begins so far out of the money, there is virtually no possibility that supra-marginal wells will arise or be suppressed during the primary term, and even a much reduced probability that the operator would gain by drilling a single sub-marginal well before the end of the primary term. Although the value of such a lease is low (since it is far out of the money), the impact of the HBP provision is large—it adds 98% to the value of the lease according to Table 4—because it gives the operator a much-needed chance to hold out for better times. The HBP option constitutes a larger share of the value of an out-of-the-money lease even though it has a lower chance of being exercised.

6. Conflicts Between Lessor and Lessee

The operator's preference regarding the timing of development is determined as part of the solution to the valuation problem—as shown in Figures 2 and 3—and follows the characteristic pattern of delay common to the exercise of all call options. Although the development option may be in the money, the operator does not invest until price reaches an even higher threshold. Moreover, optimal

[17] The probabilities shown in Figure 4 are calculated as the sum of probabilities of affected nodes shown in Figures 2 and 3. The probability of reaching any given node, π_{ij}, is given by the sum of all paths that combine $[j-1]$ downward price moves with $[i-(j-1)]$ upward price moves: $\pi_{ij} = \binom{i}{j-1} p^{i-j+1}(1-p)^{j-1}$.

timing of investment is independent of the operator's risk preference, just as the value of the option is independent of same. Facing the same set of facts and uncertainties, all operators would therefore delay development to the same degree.[18] Because delay is not necessarily agreeable to the landowner, disputes sometimes arise due to the operator's failure to initiate development in a timely manner. Many such disputes have found their way into court, as discussed by Jones and McDowell (2009). In this section we examine the strength of this conflict, explore potential time-inconsistency of the landowner's preferences, and evaluate some contractual designs that have been suggested to resolve the conflict.

The landowner's preference, once a lease has been issued, is for development and production of reserves to begin at the earliest possible time—regardless of whether those reserves are in or out of the money. This preference stems from the landowner's claim to royalties as a percentage of the gross revenue from the sale of gas. If we consider, hypothetically, the fractional interest in revenues as the landowner's underlying asset, and the landowner's cost to compel production as his exercise price, the royalty interest can be viewed as an option. And, if the landowner were granted control of development timing, the cost of exercising the option over royalty income would become zero. With a zero exercise price and royalties always in the money (as long as price is not negative), the landowner would choose immediate development.[19] This defines the conflict between landowner and operator.

Of course, landowners cannot compel operators to produce at a loss. Even if they could, the landowner's command of development timing would diminish the value of the lease and reduce the portion of the landowner's income derived from its initial sale. In the extreme, the market value of any lease currently out of the money would be zero, which precludes both its initial sale and all subsequent royalty income. This example suggests two things: (1) the various lease provisions by which landowners

[18] Independence of timing and risk preference is easily proved by contradiction. Suppose that optimal timing of the investment were not independent of the operator's risk preference. Then we have one of two possibilities. Under at least one possible price path for the reserves, S_t, either

> (a) the risk-averse owner would exercise before the risk-neutral operator. But then, at the time of exercise (τ), the value of the option must be $S_\tau - K$ to the risk-averse operator and strictly greater than $S_\tau - K$ to the risk-neutral operator, which is why he chooses further delay; or
>
> (b) the risk-neutral operator would exercise before the risk-averse operator. But then, at the time of exercise, the value of the option must be $S_\tau - K$ to the risk-neutral operator and strictly greater than $S_\tau - K$ to the risk-averse operator, which is why he chooses further delay.

Either outcome contradicts the fact that the value of the option (at all times) is independent of risk preference.

[19] This assumes that gas reserves do not appreciate as fast as money in the bank. Otherwise, the landowner would choose to wait—forever!

have attempted to influence the timing of development introduce a tradeoff between up-front bonus payments and subsequent royalties; and (2) landowners may face a time-inconsistency problem since they have incentives to adopt lease provisions that cede control to the operator at the time of sale but also to deviate from those provisions once the lease has been issued. Of course, the operator's anticipation of the time-inconsistency problem (and the potential legal costs associated with it) should be expected to influence the value of the lease.

For the present, we confine analysis to the first of these two issues. Assuming costless enforcement of the written contract between landowner and operator, and considering the combined impacts on the landowner's bonus and royalty income, we ask: What degree of agreed control over the timing of development is in the landowner's interest, if any? Much can be learned by focusing on four alternative lease forms. First is the conventional lease that incorporates the HBP option. Second is the same lease but without the HBP option (meaning that full development must be undertaken during the primary term), but which still grants the operator the option to determine investment timing within that interval. Third is a rather unconventional lease that requires the operator to undertake full development as soon as the reserves come into the money, and with no opportunity to extend the primary term. Fourth is a hypothetical lease that mandates immediate development, regardless of commerciality. The second type of lease might be considered a form of the "implied covenant to develop" that precludes the operator from undue delay (beyond the primary term), and will be designated "ICD." The third type might be considered a strong form of the "express covenant to develop" written to specifically compel the operator to undertake without delay all possible development that is economically feasible, and will be designated "ECD." The fourth type of lease is radical and seems unlikely to exist in practice but provides a useful benchmark, and will be designated "FD" for forced development.

The value of the respective leases are calculated using the methods already introduced. Values of the HBP and ICD leases are straightforward. The value of the ECD lease is determined by the maximum of $S - K$ and 0. If $S - K > 0$, then development must proceed immediately, and the operator's return is $S - K$ per MCF. If $S - K < 0$, then development is delayed until $S = K$ (if ever), and the operator's return is 0. Finally, the value of the FD lease is given simply by $S - K$ since K must be spent immediately to acquire an asset worth S.

The present value of royalty income received from a well drilled at time t (I_t)can be approximated as a simple function of the prevailing reserve value (see appendix):

(8) $$I_t = \frac{\gamma}{1-\gamma-\lambda} \times S_t \times EUR,$$

where γ is the royalty rate and λ measures operating costs as a percentage of the wellhead price of gas. The approximation assumes that production volumes decline exponentially (which is not quite true of shale gas wells) and continue forever (which imparts only a very slight bias to the result since the present value of small, distant production is near zero). We assume the royalty (γ) = 1/6 and that operating costs average 30% as a fraction (λ) of wellhead price.[20] As will be seen later, the conclusions we obtain using this approximation of royalty income appear quite robust.[21]

The expected value of royalty income at the time the lease is issued, conditional on the operator's optimal timing decision given the type of lease, is calculated by inserting values of I_t into the binomial lattice, and aggregating across nodes using appropriate weights to reflect the probability and timing of the operator's decision to drill—analogous to the procedure for calculating the value of the lease to the operator.

The resulting lease and royalty values are shown in Table 5. All background parameters are as before, and we assume the lease in question starts under water (P=\$1.00/MCF and K=\$1.50/MCF). For every combination of well spacing and lease term, the dominant form of lease, in terms of generating lease value, royalty income, and total landowner value is indicated by shading. As expected, lease values are highest with the HBP provision because this affords the operator maximum freedom to optimize development. The ECD lease speeds development of all commercial reserves and tends to generate higher royalty value than the HBP lease, especially when the primary term is long. But, in no case does the sum of ECD lease value and associated royalty approach that of the HBP lease. It is also apparent that the HBP lease dominates the ICD lease—from the landowner's perspective as well as that of the operator. Lease value and royalty value are always lower with ICD than with HBP. Consequently, we should not expect to see landowners broadly embrace either the ECD or ICD type of lease.

[20] Royalty rates tend to range between 1/8 and 1/4; we use the intermediate value of 1/6. Operating costs probably average around \$1/MCF (an estimate seen in the trade press), which would constitute 27% of the 2013 average spot price of natural gas at Henry Hub.

[21] An independent check for accuracy is possible. As shown in the Appendix, the same method of approximation used in (8) also implies: $P_t = \frac{a+r-\mu}{a(1-\lambda-\gamma)} \times S_t$, where P_t is the wellhead price of gas, a is the exponential production decline rate, r is the risk-adjusted discount rate, and μ is the expected growth rate of wellhead prices. Based on values of $a = 7\%$, $r = 7\%$, $\mu = 0\%$, $\lambda = 30\%$, $\gamma = 1/6$, and $S_t = \$1.00$, all fairly representative of 2013 conditions, the implied wellhead price would be $P_t = \$3.74$/MCF. The average spot price of gas at Henry Hub for 2013 is reported by EIA to be \$3.73/MCF.

An exception arises in situations where the landowner has too little bargaining power or skill to command a fair share of the value of the lease, in which case the ranking by royalty income is decisive. Suppose, for example, that due to asymmetric information (or simple lack of cunning), the landowner is able to capture, in addition to royalty income, only 5% of the value of the lease in the form of a front-end bonus payment. In that case, the superior royalty income generated by the ECD lease may be sufficient to compensate for its lower value, as shown in Table 6. Lease term and well spacing are influential here since short terms and wide spacing tend to reduce the value of the HBP option and make the ECD lease more attractive holding all else equal. Using the bonus percentage as a measure of the landowner's "bargaining power," Table 7 reports the minimum bargaining power consistent with landowner preference for HBP. It appears that only extremely disadvantaged landowners (e.g., bargaining power less than 25%) would prefer the ECD form of lease. Yet, there are many signs that landowners push (and litigate) to accelerate development after HBP leases have been issued. If our analysis is correct, this probably reflects opportunistic behavior motivated by the time-inconsistency problem that was mentioned earlier.

The fourth type of lease (FD) mandates development regardless of commerciality. This generates the highest expected royalty income for the landowner—by far—but is preferred by no one. Because it imposes substantial losses on the operator, the landowner would have to pay someone to operate the lease (i.e., a negative bonus), and the required payment far exceeds the value of resulting royalty income.

The overall conclusion that emerges from the comparison of lease types is that it is usually advantageous for landowners to cede control of investment timing to the operators, which is achieved to the fullest extent by the traditional HBP type of lease. Attempts to accelerate royalty income by inserting an express covenant to develop may in extreme cases provide a partial remedy for asymmetric information or lack of bargaining prowess, but more generally seem ill-advised. They are likely to backfire if written into the lease, but also if they are merely anticipated by an operator who recognizes the time-inconsistency of the landowner's preferences.

7. A Comparison of the Major U.S. Shale Gas Basins

As of 2013, five basins (Barnett, Fayetteville, Haynesville, Marcellus, and Woodford-Arkoma) accounted for about 75% of total U.S. production of shale gas, as shown in Figure 5. All five are dry-gas plays, which means that production consists primarily of natural gas, with only minimal volumes of oil and natural gas liquids mixed in.[22] It seems reasonable to assume that natural gas prices, rather than the price of oil or natural gas liquids, drives investment in these basins. A wealth of information about drilling costs, production rates, and well spacing exists for each basin, with marked heterogeneity among basins due to variations in prospect depth, geological attributes, and local regulation. In this section, we will examine some recent data to identify differences in the potential impact of the HBP provision within and between basins.

As shown previously, the HBP provision may either stimulate or suppress drilling, depending on the value of gas reserves, and this effect should be impounded in observed drilling rates. The analysis reported here must be regarded as preliminary, however, since we lack data on several important variables that would impact the decision to drill, like variations in the remaining term of outstanding leases, variations in well spacing within basins, and variations in drilling cost due to variations in depth. Despite these deficiencies, the methods demonstrated here may be helpful to analysts and investors with access to more complete and detailed data.

The physical characteristics of the chosen basins are summarized in Table 8.[23] The Marcellus shale covers the largest area, almost 95,000 square miles. The Woodford-Arkoma is the smallest, at 2,900 square miles. Average cost per well ranges from \$2.5 million in the Fayetteville to \$8 million in the Haynesville. The high cost of Haynesville wells is due to the depth of the shale, which averages 12,000 feet below the surface, whereas the Fayetteville shale is encountered only 4,000 feet below the surface. Average well spacing varies between 80 and 160 acres across the basins, while average EURs vary from 1.93 million MCF per well (Barnett) to 8.13 million MCF per well (Marcellus).

As discussed earlier, there is considerable variation around the mean for each of these physical characteristics within each basin, and a more definitive analysis would take such variations into account, as opposed to overall averages. But, finer data are available only regarding EUR, so we are limited to that. Several years ago, EIA (2011) published basin-specific probability distributions of EUR. Those estimates show how EUR is expected to vary within and between the so-called “Best,” “Average” and “Below Average” areas of each basin. Since those estimates were prepared several years ago, technological advances have improved the EURs achieved in certain areas. In other areas, subsequent

[22] Gas production from the Woodford shale also comes from the Anadarko Basin, which is not dry-gas, but liquid-rich (25-30% liquids).
[23] Data on area, shale depth, and well spacing come from U.S. Energy Information Administration (2011). Estimated well cost and average EUR are based on confidential information received from a private source, as discussed later.

experience has shown that initial estimates were too favorable. Therefore, we have updated EIA's original distributions by substituting current estimates of the mean EUR for each area; but to preserve heterogeneity within each basin we retain the original coefficient of variation.[24] The updated distributions are shown in Table 9.

Since well costs are taken as fixed for each basin, the variation in EUR for a given area induces a probability distribution on development cost, which is given by $K = C/EUR$.[25] These cost distributions are shown in Table 10 and range from a low of \$0.35/MCF to a high of \$9.44/MCF. Based on estimates developed by Smith (2014), we will assume the value of reserves to be \$1.00 per MCF. Thus, any region with development cost in excess of \$1.00/MCF is out-of-the-money. Such regions are shaded in Table 10. Consistent with many pronouncements heard elsewhere, only the best wells in the best portions of these basins are above water at current price levels. The Marcellus, where nearly 60% of the wells are in-the-money, appears most favorable. This contrasts sharply with the Haynesville, where less than 10% make the cut.

Distributions of lease values are estimated by substituting the respective EURs, well spacings, and cost parameters into the HBP valuation algorithm, assuming a common lease term of 3 years. The results are tabulated in Table 11, which shows an order-of-magnitude difference between the value of best and worst leases within each basin. This is not surprising given that the underlying EURs also vary by an order of magnitude.[26] This also explains the industry's fascination with so-called "sweet spots" and shows the value of being able to distinguish between locations. Average lease values, which vary from about \$4,000 to nearly \$75,000 per acre, are also computed for each sub-area within the basins. The Marcellus—where the average value of a lease located in the average part of the basin approaches \$50,000 per acre—stands apart. Chesapeake's 2014 sale of shale gas leases covering 413,000 acres in the Marcellus and nearby Utica shale basins provides a recent point of reference.[27] After backing out the estimated value of already producing wells, we estimate the price of undeveloped shale gas leases

[24] Indicative EURs were obtained for each basin from an investment bank that serves many clients involved in these shale gas basins, based on assessments taken in late 2013. Each quantile of the EIA's original distribution for a given basin was then multiplied by a fixed constant until the indicative EUR value corresponded to the 70% percentile of the adjusted distribution. The rationale is that the indicative value roughly corresponds to the mean for wells that are most likely to be drilled, which excludes the bottom tail of the distribution.

[25] Consistent with our investment banking source of data, we assume that total development costs amount to 125% of the cost of the well, which recognizes that additional expenditures will be required at the drill site.

[26] The U.S. Geological Survey (2012) finds that the extreme tails of typical EUR distributions may differ by two orders of magnitude, somewhat greater than reflected in the distributions adopted in our study.

[27] Details of the Chesapeake sale are reported in the Wall Street Journal (2014).

included in that transaction to be roughly $15,000 per acre.[28] Since we have no information about the quality of those leases, the comparison does not prove much, except that—consistent with our estimates—leases are selling for much more in the Marcellus basin than elsewhere in the U.S. As reported earlier, the average price of U.S. shale gas leases in 2013 probably did not exceed $2,000 per acre.

One question of principal interest: How much does the HBP provision add to the value of typical leases in each of the major shale basins? The answer comes by comparing the lease values reported in Table 11 to the estimated values if the HBP provision were absent (calculated by the same method as in Table 2). This comparison is presented in Figure 6, which shows substantial variation across basins. On average, the HBP provision adds between 30% (Marcellus) and 210% (Haynesville) to the value of the lease.[29] The relative value of the option is uniformly lowest in above-average portions of each basin, presumably because the value of these leases is high even without the HBP provision and the potential profitability of the very best drilling locations argues against delay. For the same reason, the relative value of the HBP option is uniformly lower in the Marcellus basin (where leases are on average deeper in-the-money, than elsewhere. However, the HBP option premiums in every part of each basin are substantial, which signals that conditions in all basins are such that an operator may wish to extend the term of his lease, whether by the drilling of a sub-marginal well on a lease that is under water, or by refraining from fully developing a lease that is above water.

The last step in the analysis is to identify the directional impact of the HBP provision on drilling within each area of the five basins. This is accomplished by computing the probability of: (a) a sub-marginal well being drilled at the end of the primary term to hold the lease, and (b) supra-marginal wells being delayed at the end of the primary term in order to postpone full development beyond the primary term. The method of computation is the same as shown previously in Figure 4. The results, shown in the three panels of Figure 7, reveal sharp differences between basins.[30] Comparing the best areas of

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28 Chesapeake's production from existing wells included in the sale is reported as 122.64 BCF per year. If we assume the average extraction rate is 15% per year, then total proved gas reserves would amount to 817.6 BCF. We value these at $1/MCF and deduct the resulting figure of $817 million from $5.38 billion, the total value of the sale, leaving $4.56 billion as the value of undeveloped acreage (and possibly some infrastructure like gas processing plants about which we have no information). If we assume 80 acre well spacing, the 1,500 existing wells would drain 120,000 acres, leaving 293,000 of the total 413,000 included in the transaction as undeveloped. Our estimated value of $15,571 per undeveloped acre is then obtained by dividing $4.56 billion by 293,000 acres.

29 A detailed breakdown of these results by quantile within each area of each basin is presented in Appendix Table A1.

30 Detailed results by quantile within each area of each basin are tabulated in Appendix Table A2 and charted in Appendix Figure A1.

each basin (Panel A), the Marcellus stands out with a strong tilt towards the suppression of drilling. A similar effect exists in the Barnett and Woodford, but to a lesser extent. The directional impacts are roughly offsetting in the Fayetteville, but in the Haynesville the effect is strongly in favor of stimulating drilling. These results are consistent with the fact that the Marcellus is judged to contain more in-the-money leases than the other basins, many of which would be delayed in favor of future development. The Haynesville basin, where most leases are currently under water, is at the other extreme. There, the probability that an under-water lease will be drilled to extend the term is much higher than the probability that an above-water well will be postponed, and this is true in all portions of the basin (cf. Panels, A, B, and C). In every basin, it appears the impact of the HBP option in below-average areas is to stimulate drilling.

There are several important caveats to keep in mind when considering our results. First, estimated unit costs are derived from and vary inversely with the estimated EURs. If EUR is overstated, development cost per unit, $K = C/EUR$, will be understated. These errors do not cancel out; they both tend to raise the estimated value of the lease. Likewise, if the EUR is understated, development cost will be overstated, which tends to lower the estimated value of the lease. Combined, these effects mean that our reported range of lease values may be too wide. The value of leases in the upper tail are probably overstated and those in the lower tail are probably understated. However, we do not believe this problem should impact the average lease value we report for any particular area.

Second, development cost and EUR are linked in a more fundamental way. By extending the lateral length of a well and completing more fracking stages (both of which incur higher cost), an operator can probably achieve higher EUR. Whether this increases the per unit development cost (K) is debatable, but with diminishing returns to the length of a lateral, it could. Therefore, it is essential that the EUR figures employed in the analysis be consistent with the type and cost of the reported development well. Because our EUR estimates and well cost estimates come from the same source, we believe they are consistent.

Third comes the question of whether an unconstrained optimization model, like the option valuation model, is appropriate when considering investments that may be constrained during a boom either by a lack of drilling rigs or by a lack of capital with which to employ them. Here we take no stand on whether such constraints have been binding. But, we doubt the implications of our analysis would be much affected either way. If the pace of drilling is constrained, we expect that operators would still be motivated by the option value of holding a lease. And, once the lease has been held, a capital constraint would only decrease the incentive to drill additional supra-marginal wells, which in turn reinforces the negative effect of option value on the decision to drill supra-marginal wells.

We close with a brief but illuminating analysis of the actual drilling data. Figure 8 relates drilling activity in the dry shale gas basins to the price of natural gas.[31] Since the shale gas boom first emerged, the rate of new well completions has closely paralleled movements in the price of natural gas. There is no obvious evidence of overdrilling, at least not if we interpret that to mean operators have ignored the substantial drop in the price of gas that began after 2008. Since 2006, the correlation between annual changes in new well completions and changes in the spot price of gas is 93%. As prices moved up, then down, the number of new wells moved almost in lock step. It appears that operators have, at least in the aggregate, responded to price incentives. We would also argue that the pattern shown in Figure 8 is not inconsistent with the presence of more subtle variations in drilling decisions at the micro level triggered by the option to hold the lease. As we have shown, those incentives cut both ways, across basins and even within basins, increasing the number of wells in certain areas but simultaneously decreasing it elsewhere. In this sense, the HBP provision acts as a kind of stabilizer, restraining the rate of drilling in hot basins but sustaining drilling rates everywhere else. It would take careful analysis of a large and representative sample of drilling on individual leases to perform a strong test of the theory, a task that we leave for future research.

8. Conclusion

The provisions of a petroleum lease determine the value of rights conveyed to the operator, the landowner's share of all proceeds, and—not least—the pace of development. We have shown how the HBP provision, in particular, affects all three. These impacts are quite specific to the lease in question, depending on the cost of drilling, the EUR per well, and the ratio of a well's drainage area to the total area under lease. The HBP option may stimulate drilling on one lease while suppressing drilling on others nearby. We have demonstrated that substantial variation in the size of these effects can be expected both within and between the major shale gas basins in the U.S.

[31] The figure shows the total number of new gas well completions in the five major dry gas basins of the U.S. (Marcellus, Haynesville, Barnett, Fayetteville, and Woodford). The figure does not include gas wells drilled in oil or liquid-rich gas plays, where drilling activity may have been buoyed by the relatively strong price of oil and natural gas liquids which are produced as a by-product of natural gas. Well completion data were supplied by the U.S. Energy Information Administration.

The drilling of many sub-marginal wells has been cited as evidence of “overdrilling” at the same time that landowners complain about the industry’s slow pace of development. Interpreting the HBP provision as a compound option reconciles these two views. In neither case, from the perspective of real options, is there any evidence of irrational behavior—either on the part of operators or landowners. By comparing the impact of the HBP provision to the effects of alternative provisions designed to speed development (and the receipt of royalty income), we have shown that, barring an extreme imbalance in bargaining power of the two sides, the HBP provision is a dominant form—preferred over all alternatives by both parties to the lease. We argue that disputes regarding the pace of development that arise after the lease has been issued reflect a time-inconsistency problem, a problem that would disappear with clear definition and costless enforcement of the terms of the lease.

Although we have illustrated the effects of the HBP option by reference to the major dry-gas shale basins in the U.S., the same method of analysis could be applied to shale oil leases, as well as conventional (non-shale) petroleum resources of all types. The salience of applications to shale oil development may increase if oil prices continue to decline and push more oil leases underwater—as happened in the case of natural gas.

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Appendix: Valuing the Royalty Interest

A well showing exponential decline at the rate (a) from initial production level (q_o) is described by the equation:

(A1) $$q_t = q_0 exp^{-at}.$$

Integrating production over the life of the well determines EUR:

(A2) $$EUR = \int_0^\infty q_t dt = q_0 \int_0^\infty exp^{-at} dt = \frac{q_0}{a}.$$

We assume the wellhead price of gas (P) follows the stochastic process:

(A3) $$\frac{dP}{P} = \mu dt + \sigma dz.$$

where μ represents the instantaneous return and σ is the standard deviation of a standard Wiener process. The unit value of the reserve (S) is given by the present value of the operator's expected net cash flow from production:

(A4) $$S = E\left[\int_0^\infty (P_t - OC_t - ROY_t) q_t exp^{-rt} dt\right] / EUR,$$

where OC represents unit operating costs, ROY represents unit royalties, and r is the risk-adjusted discount rate. We will assume that operating cost and royalty are a constant percentage of the wellhead price. Thus: $OC_t = \lambda P_t$ and $ROY_t = \gamma P_t$. Upon substitution, Equation A4 becomes:

(A5) $$\begin{aligned} S &= E\left[\int_0^\infty P_t (1 - \lambda - \gamma) q_0 exp^{-(a+r)t} dt\right] / EUR \\ &= (1 - \lambda - \gamma) q_0 P_0 \int_0^\infty exp^{-(a+r-\mu)t}\, dt / EUR \\ &= (1 - \lambda - \gamma) \left(\frac{a}{a+r-\mu}\right) P_0. \end{aligned}$$

The present value of the landowner's royalty interest is given by:

(A6) $$I = E\left[\int_0^\infty \gamma P_t q_t exp^{-rt} dt\right]$$

$$= \gamma P_0 q_0 \int_0^\infty exp^{-(a+r-\mu)t} dt$$

$$= \left(\frac{a}{a+r-\mu}\right) \gamma P_0 EUR.$$

From Equation A5, we know:

(A7) $$\left(\frac{a}{a+r-\mu}\right) P_0 = \frac{S}{1-\lambda-\gamma}.$$

After substituting this into Equation A6, we have:

(A8) $$I = \left(\frac{\gamma}{1-\gamma-\lambda}\right) S \times EUR,$$

which corresponds to Equation (8) of the text.

Figure 1: Binomial Lattice of Price Movements and Lease Values

The diagram shows all possible evolutions of the value of proved reserves (S_{tj}). The value of an undeveloped lease with the HBP provision is represented by V^{+}_{tj}, as defined by Equation (5) of the text. The probability of an upward price movement at each node is constant and represented by p. The value of a lease with fixed primary term is represented by V_{tj}, as defined by Equation (4) of the text.

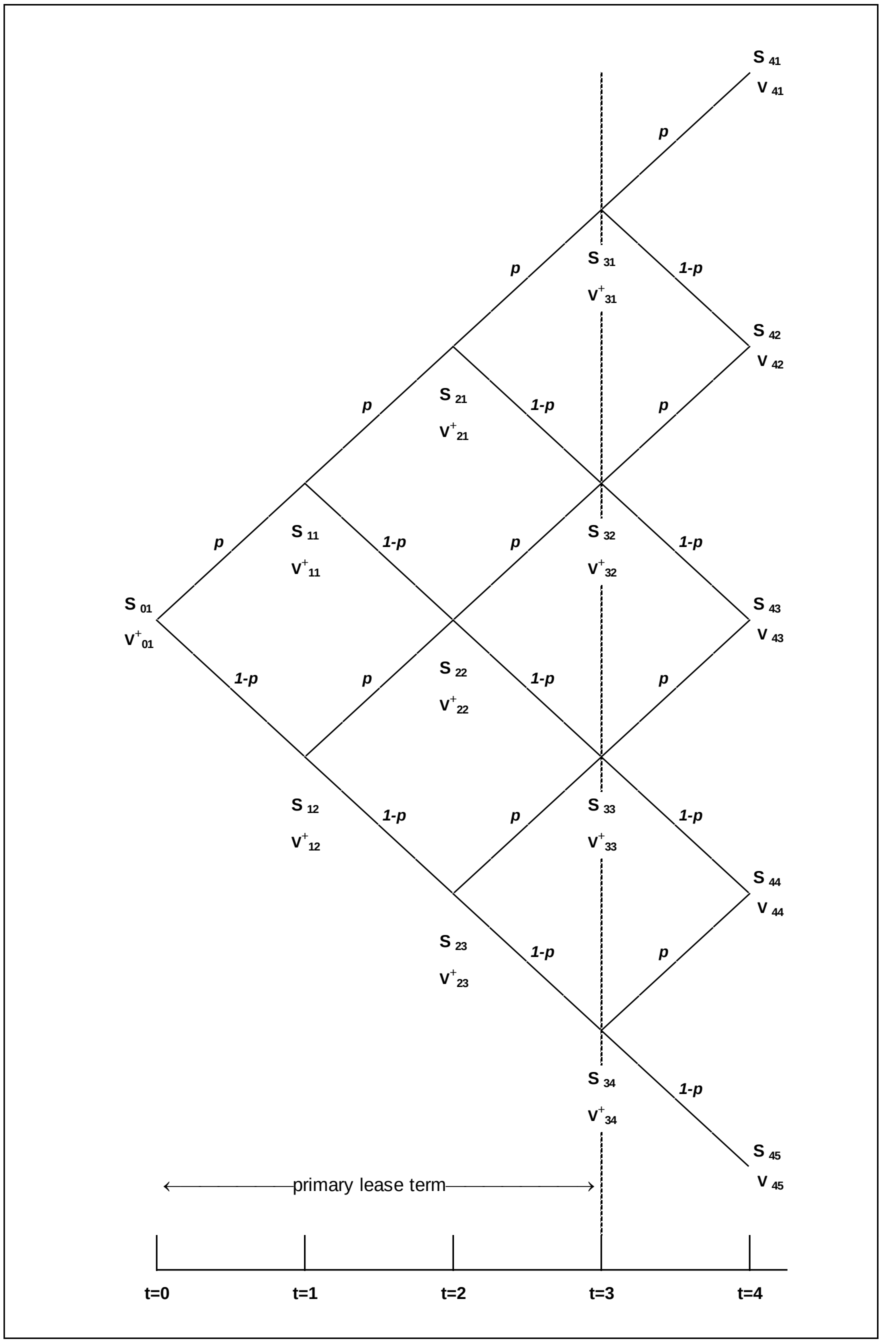


Figure 2: Optimal Development Timing: Even-Money Lease

The diagram depicts the full 25-step binomial price lattice used to value an undeveloped lease, including the optimal timing of investment. No investment should be made at nodes marked “O”. Full development should be initiated at nodes marked “X”. A single well should be drilled (to hold the lease by production) at nodes marked “D1”. Without the HBP provision in the lease, all white cells switch to “X” and all yellow cells switch to “O”. The white and yellow cells therefore show the impact of the HBP option on the scope and timing of investment. The lease in question is assumed to begin at even money at time t_o with $P = K = \$1.00$/MCF. Primary term is 3 years, EUR is 1 BCF per well, lease area is 640 acres with 80 acre spacing, which gives 8 wells. Volatility of reserve value is 50%; the real interest rate is 2%, and convenience yield is 1%.

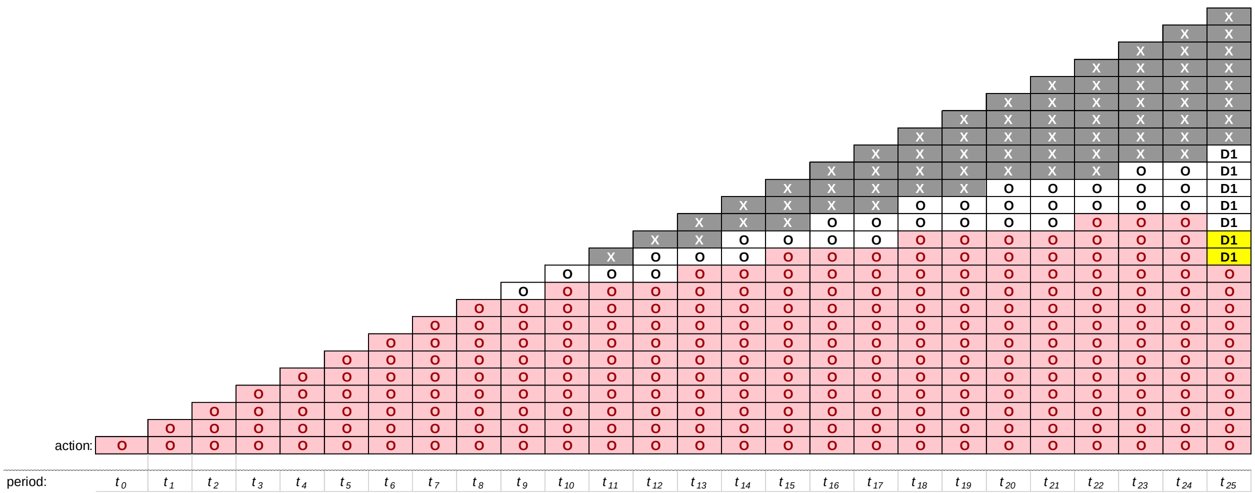


Figure 3: Optimal Development Timing: Out-of-the-Money Lease

The diagram depicts the full 25-step binomial price lattice used to value an undeveloped lease, including the optimal timing of investment. No investment should be made at nodes marked “O”. Full development should be initiated at nodes marked “X”. A single well should be drilled (to hold the lease by production) at nodes marked “D1”. Without the HBP provision in the lease, all white cells switch to “X” and all yellow cells switch to “O”. The white and yellow cells therefore show the impact of the HBP option on the scope and timing of investment. The lease in question is assumed to begin out of the money at time t_o with $P = \$1.00/MCF$ and $K = \$3.00/MCF$. Primary term is 3 years, EUR is 1 BCF per well, lease area is 640 acres with 80 acre spacing, which gives 8 wells. Volatility of reserve value is 50%; the real interest rate is 2%, and convenience yield is 1%.

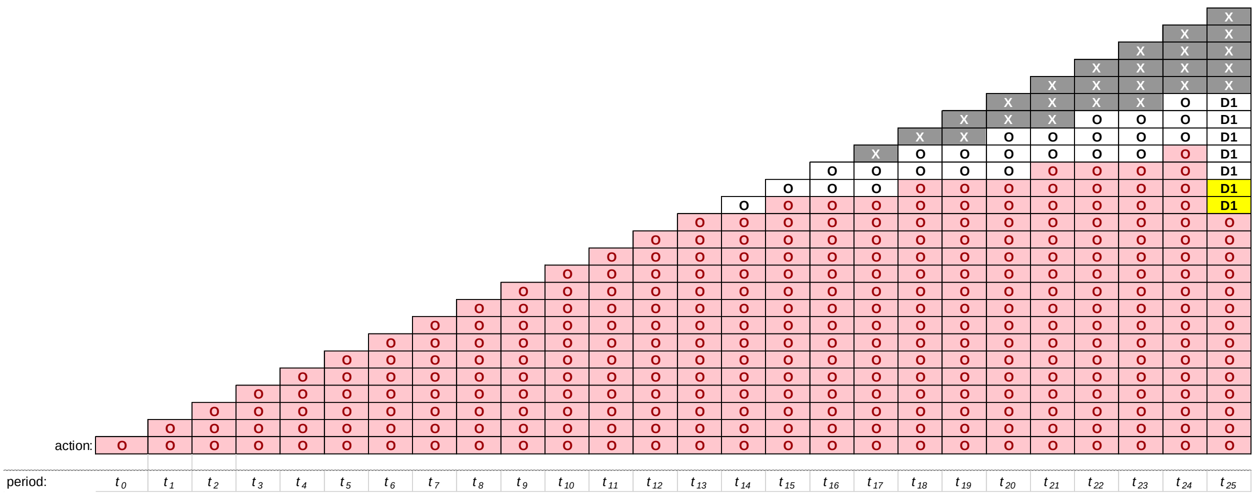


Figure 4: Probability of Exercising the HBP Option

The graph shows the conditional probability, at each point during the primary term of the lease, that the operator will drill a single well (as opposed to either drilling no well or initiating full development). The blue line is derived from the optimal investment decisions for the even-money lease shown in Figure 2. The red line is derived from the optimal investment decisions for the out-of-the money lease shown in Figure 3. In both cases, the lease is 640 acreas with 80 acre spacing, so 8 wells are required for full development. The primary term is for a period of 3 years, so each of the 24 time-steps represents the passage of 45 days.

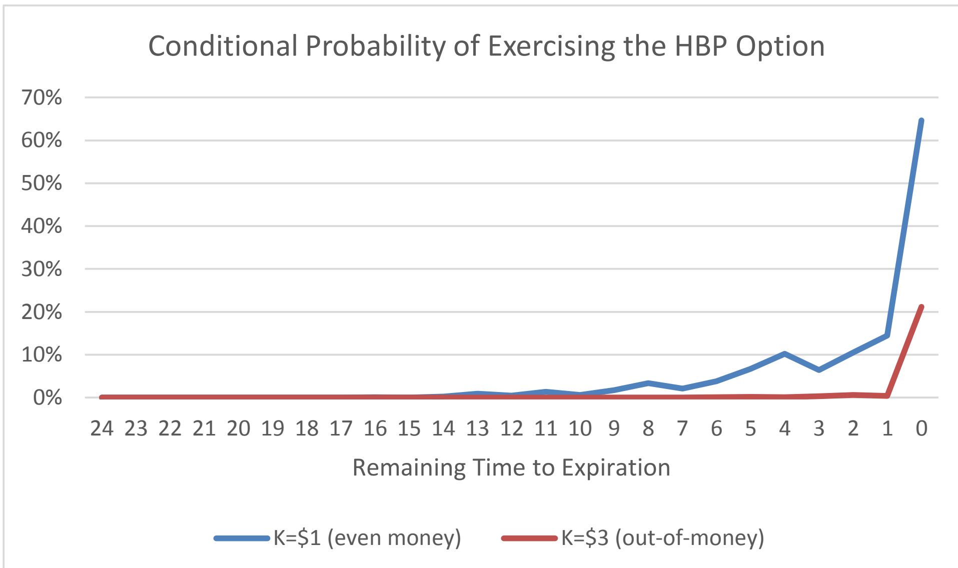


Figure 5: U.S. Shale Gas Production, by Basin

The chart shows total production of dry natural gas (natural gas liquids removed), by month, from each of the five main shale gas basins in the U.S. Shale gas production from the rest of the U.S. comes mainly from the Antrim, Bakken, Eagle Ford, and Utica basins. Source: U.S. Energy Information Administration.

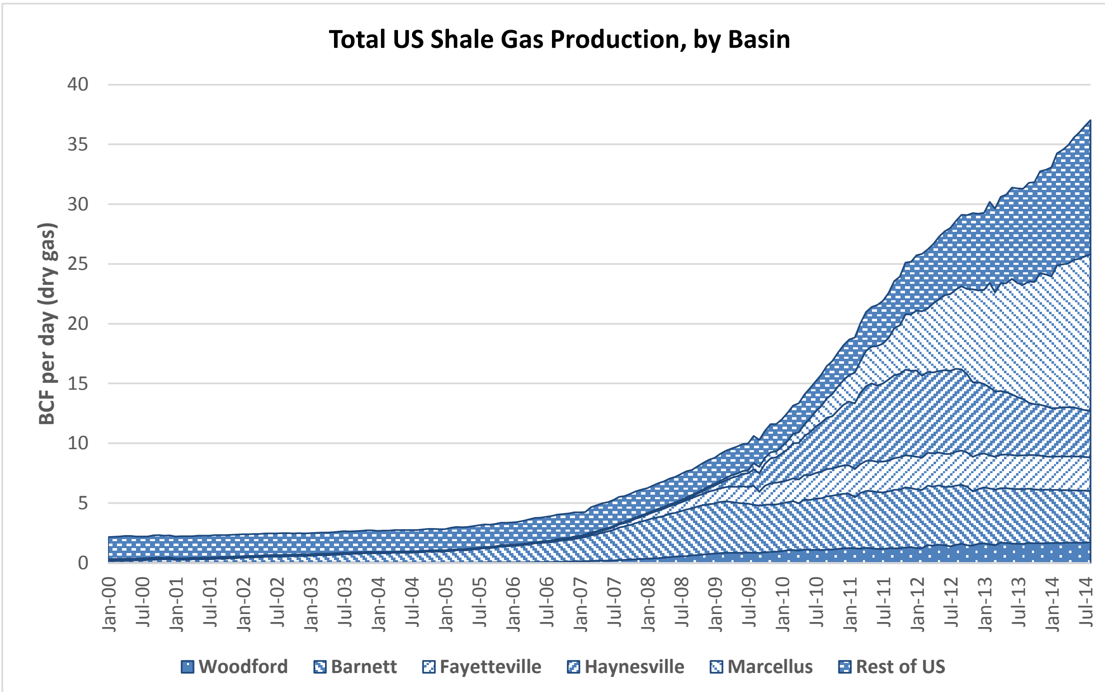


Figure 6: Variation in Lease Values With and Without HBP Option, by Basin and Area

The figure shows, for each area, the value of a three-year lease that includes the HBP provision relative to the value of a comparable lease without the HBP provision. Within each major shale gas basin, results are disaggregated on the basis of expected ultimate recovery (EUR) of representative wells from the best, average, and below-average subdivisions. Physical characteristics of each area (e.g., formation depth, well spacing, well cost, and average EUR per well) are as described in Tables 8 and 9.

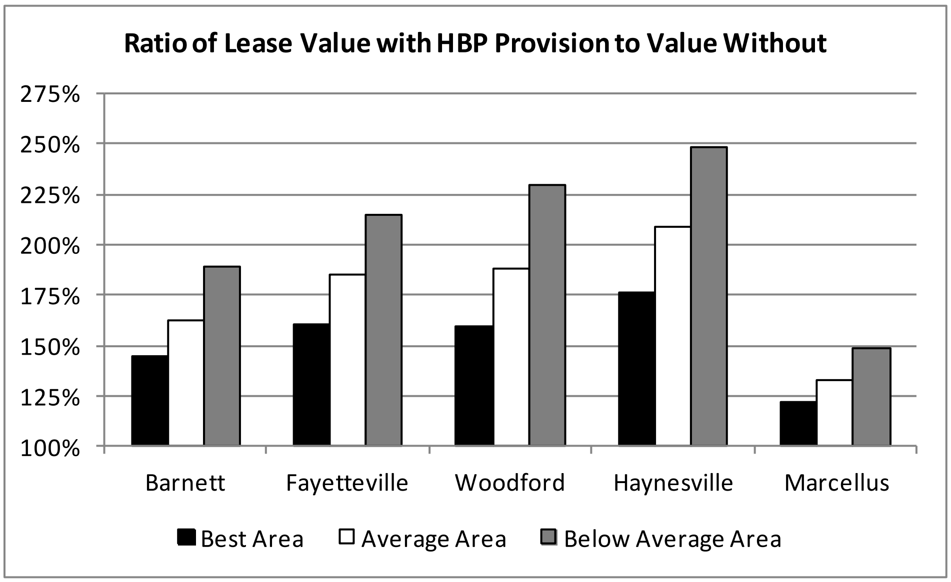
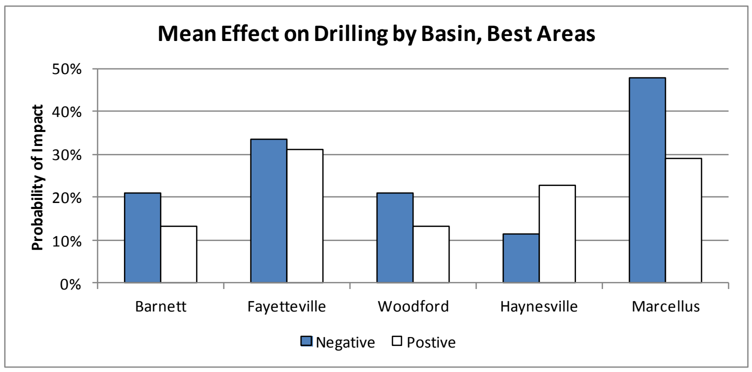


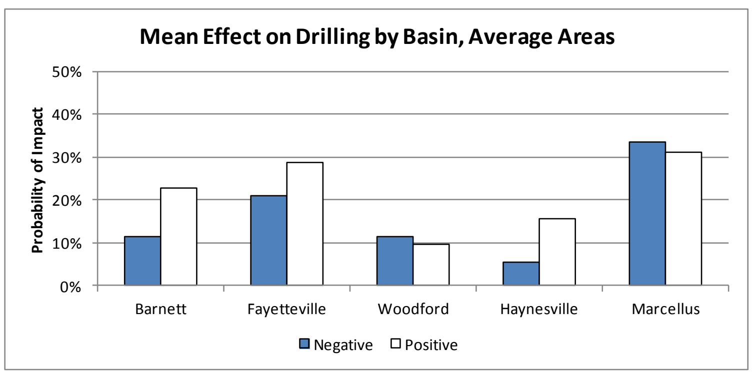
Figure 7: Impact of HBP Option on Drilling During Primary Term, by Basin

These three panels show the probability that the HBP option will be exercised during the primary term of a three-year lease, and thereby impact development investment relative to a comparable lease that lacks the HBP provision. The three panels refer to sub-areas within each major shale gas basin that correspond to expected ultimate expected recovery (EUR) from the best, average, and below-average wells. Blue bars show the probability that a sub-marginal well will be drilled during the primary term due to the HBP provision. White bars show the probability that supra-marginal wells will be deferred due to the HBP provision. Physical characteristics of each area (e.g., formation depth, well spacing, well cost, and average EUR per well) are as described in Tables 8 and 9.

Panel A (Best Areas)



Panel B (Average Areas)



Panel C (Below Average Areas)

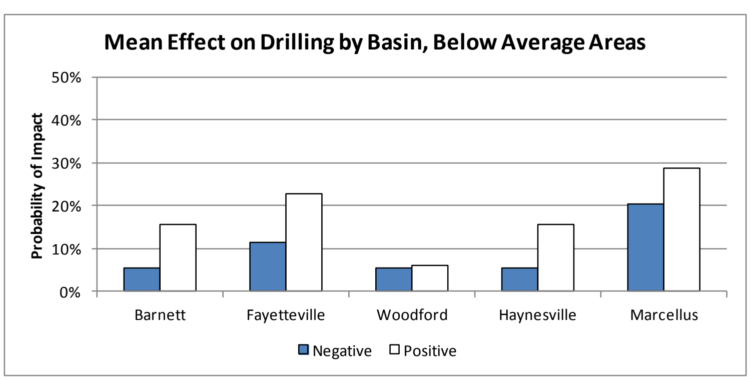


Figure 8: Shale Gas Well Completions in Five Dry-Gas Basins

The chart shows the number of shale gas wells completed on an annual basis in the five major shale gas basins. Basins are defined at the county level of granularity. Since basins do not correspond to state boundaries, these well counts deviate from the reported number of wells completed in the various states. For comparison, the annual average spot price of natural gas reported at the Henry Hub (Louisiana) terminal is measured on the right axis. Source: U.S. Energy Information Administration.

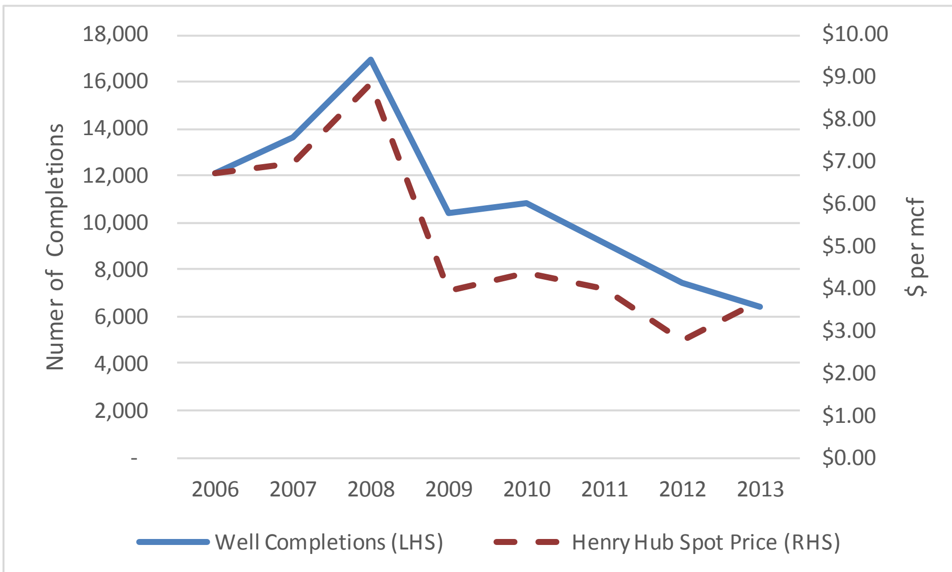


Table 1: Value of Hypothetical Leases with HBP Provision

The table shows how the value of a 640-acre natural gas lease with the HBP provision varies as a function of the primary term of the lease and well spacing. A longer term increases the value of the lease because prices are assumed to follow Geometric Brownian Motion which creates increasing scope for high prices as time progresses. Wider well spacing reduces the value of the lease because it constrains the operator's ability to drill additional wells beyond the first after exercising the option to hold by production. It is assumed that the lease begins well out-of the-money ($P = \$1.00/MCF \; and \; K = \$1.50/MCF$), with EUR = 1 BCF/well. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equation (5) of the text.

		Lease Value per Acre, with HBP Option				
	Well Spacing:	40	80	160	320	640
Lease Term	1	$3,368	$1,553	$679	$286	$115
	2	$6,081	$2,844	$1,301	$566	$232
	3	$8,134	$3,860	$1,774	$775	$336
	4	$9,730	$4,637	$2,140	$958	$419
	5	$10,996	$5,258	$2,436	$1,108	$489
	6	$12,026	$5,767	$2,681	$1,234	$549

Table 2: Ratio of Lease Values With and Without the HBP Option

The table shows the impact of lease term and well spacing on the value of a 640-acre natural gas lease with the HBP provision relative to the value of a comparable lease that lacks the HBP provision. A longer term reduces the relative value of the HBP provision since the option to extend the primary term is less important if the primary term is already long. Wider well spacing reduces the relative value of the HBP provision because it constrains the operator's ability to drill additional wells beyond the first after exercising the option to hold by production. In the extreme, if spacing is limited to one well per 640 acres, the HBP provision has no value for a 640-acre lease since there are no additional wells to be exploited. It is assumed that the lease in question begins well out-of the-money ($P = \$1.00/MCF \; and \; K = \$1.50/MCF$), with EUR = 1 BCF/well. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equations (4) and (5) of the text.

		Ratio of Lease Values, With and Without HBP Option				
	Well Spacing:	40	80	160	320	640
Lease Term	1	183%	169%	148%	124%	100%
	2	164%	153%	140%	122%	100%
	3	151%	144%	132%	115%	100%
	4	145%	138%	128%	114%	100%
	5	141%	134%	125%	113%	100%
	6	137%	131%	122%	112%	100%

Table 3: Value of Out-of-the Money Leases with HPB Provision

The table shows how the value of a 640-acre natural gas lease with the HBP provision and 160-acre spacing varies as a function of the primary term of the lease and unit development cost. A longer term increases the value of the lease because prices are assumed to follow Geometric Brownian Motion which creates increasing scope for high prices as time progresses. Higher development cost decreases the value of the lease because it reduces the chance of profitable development. The price of reserves is assumed to be $P = \$1.00/MCF$, with EUR = 1 BCF/well. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equation (5) of the text.

		Lease Value per Acre, with HBP Option				
	Cost per MCF:	\$0.50	\$1.00	\$2.00	\$3.00	\$4.00
Lease Term	1	3,325	1,536	304	65	14
	2	3,579	2,117	829	357	170
	3	3,788	2,523	1,283	739	447
	4	3,954	2,834	1,663	1,081	758
	5	4,084	3,083	1,991	1,415	1,061
	6	4,196	3,288	2,276	1,715	1,315

Table 4: Significance of the HBP Provision on Out-of-the-Money Leases

The table shows the impact of lease term and unit development cost on the value of a 640-acre natural gas lease with 160-acre spacing and the HBP provision, relative to the value of a comparable lease that lacks the HBP provision. A longer term reduces the relative value of the HBP provision since the option to extend the primary term is less important if the primary term is already long. Higher development cost decreases the relative value of the HBP provision because it reduces the chance that the development option will be exercised during an extended term. It is assumed that the value of reserves is $P = \$1.00/MCF$, with EUR = 1 BCF/well. It is also assumed that the volatility of the value of proved reserves is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equations (4) and (5) of the text.

		Ratio of Lease Values, With and Without HBP Option				
	Cost per MCF:	\$0.50	\$1.00	\$2.00	\$3.00	\$4.00
Lease Term	1	104%	122%	191%	292%	316%
	2	106%	121%	160%	182%	212%
	3	107%	119%	143%	167%	184%
	4	107%	118%	138%	155%	180%
	5	108%	117%	136%	152%	158%
	6	107%	115%	132%	142%	149%

Table 5: Impact of Lease Provisions on Lease Value vs. Royalty Value

The table shows the potential value of a 640-acre, three-year lease from the landowner's perspective and breaks out variations due to lease term, well spacing, and the landowner's degree of control over investment timing. The left section reports the value of the lease at time of issuance, which is the most the landowner may expect to receive in the form of front-end bonus payments. The center section reports the present value of the landowner's royalty income. The right section reports the total value captured by the landowner assuming that he receives the full value of the lease at issuance in addition to royalty income. The upper panel represents a lease which mandates immediate development regardless of commerciality. The second panel represents a lease which mandates development as soon as the reserves are commercial, with no option to delay beyond that point. The third panel represents a lease with the HBP provision. The fourth panel represents a lease without the HBP provision, but which allows development any time before expiration of the primary term. The royalty rate is assumed to be 1/6, reserve value is \$1.00/MCF, and development cost is \$1.50/MCF. Shaded cells indicate the form of lease that maximizes lease value, royalty income, and total landowner's value for each combination of lease term and well spacing.

											100% Bonus Factor (Landowner Share of Lease Value)				
	FD: Lease Value With Forced Development					FD: Royalty Value Wth Forced Development					FD: Total Landowner Value With Forced Development				
Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term 1	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
2	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
3	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
4	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
5	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
6	-\$12,500	-\$6,250	-\$3,125	-\$1,563	-\$781	\$7,813	\$3,906	\$1,953	\$977	\$488	-\$4,688	-\$2,344	-\$1,172	-\$586	-\$293
	ECD: Lease Value With Express Covenant if Commercial					ECD: Royalty Value With Express Covenant if Commercial					ECD: Total Landowner Value W/ Express Cov. if Comm.				
Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term 1	\$0	\$0	\$0	\$0	\$0	\$3,262	\$1,631	\$815	\$408	\$204	\$3,262	\$1,631	\$815	\$408	\$204
2	\$0	\$0	\$0	\$0	\$0	\$5,284	\$2,642	\$1,321	\$660	\$330	\$5,284	\$2,642	\$1,321	\$660	\$330
3	\$0	\$0	\$0	\$0	\$0	\$5,467	\$2,733	\$1,367	\$683	\$342	\$5,467	\$2,733	\$1,367	\$683	\$342
4	\$0	\$0	\$0	\$0	\$0	\$5,612	\$2,806	\$1,403	\$701	\$351	\$5,612	\$2,806	\$1,403	\$701	\$351
5	\$0	\$0	\$0	\$0	\$0	\$6,455	\$3,227	\$1,614	\$807	\$403	\$6,455	\$3,227	\$1,614	\$807	\$403
6	\$0	\$0	\$0	\$0	\$0	\$6,527	\$3,263	\$1,632	\$816	\$408	\$6,527	\$3,263	\$1,632	\$816	\$408
	HBP: Lease Value With HBP Option					HBP: Royalty Value With HBP Option					HBP: Total Landowner Value With HBP Option				
Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term 1	\$3,368	\$1,553	\$679	\$286	\$115	\$3,313	\$1,557	\$673	\$369	\$145	\$6,681	\$3,110	\$1,352	\$655	\$260
2	\$6,081	\$2,844	\$1,301	\$566	\$232	\$4,369	\$2,239	\$1,030	\$434	\$237	\$10,450	\$5,082	\$2,331	\$1,000	\$469
3	\$8,134	\$3,860	\$1,774	\$775	\$336	\$4,874	\$2,370	\$1,095	\$580	\$251	\$13,009	\$6,230	\$2,869	\$1,355	\$587
4	\$9,730	\$4,637	\$2,140	\$958	\$419	\$5,077	\$2,470	\$1,145	\$603	\$263	\$14,807	\$7,108	\$3,285	\$1,561	\$682
5	\$10,996	\$5,258	\$2,436	\$1,108	\$489	\$5,240	\$2,552	\$1,187	\$623	\$273	\$16,236	\$7,810	\$3,622	\$1,731	\$762
6	\$12,026	\$5,767	\$2,681	\$1,234	\$549	\$5,378	\$2,623	\$1,224	\$638	\$282	\$17,404	\$8,389	\$3,905	\$1,872	\$830
	ICD: Lease Value Without HBP Option										ICD: Total Landowner Value Without HBP Option				
Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term 1	\$1,841	\$921	\$460	\$230	\$115	\$2,314	\$1,157	\$578	\$289	\$145	\$4,155	\$2,077	\$1,039	\$519	\$260
2	\$3,706	\$1,853	\$927	\$463	\$232	\$3,791	\$1,896	\$948	\$474	\$237	\$7,498	\$3,749	\$1,874	\$937	\$469
3	\$5,372	\$2,686	\$1,343	\$671	\$336	\$4,022	\$2,011	\$1,005	\$503	\$251	\$9,394	\$4,697	\$2,348	\$1,174	\$587
4	\$6,706	\$3,353	\$1,676	\$838	\$419	\$4,207	\$2,104	\$1,052	\$526	\$263	\$10,913	\$5,456	\$2,728	\$1,364	\$682
5	\$7,821	\$3,910	\$1,955	\$978	\$489	\$4,365	\$2,182	\$1,091	\$546	\$273	\$12,186	\$6,093	\$3,046	\$1,523	\$762
6	\$8,777	\$4,388	\$2,194	\$1,097	\$549	\$4,508	\$2,254	\$1,127	\$564	\$282	\$13,285	\$6,642	\$3,321	\$1,661	\$830

Table 6: Impact of Bargaining Power on Landowner's Total Return (Lease Bonus + Royalty)

The table shows the potential value of a 640-acre, three-year lease from the landowner's perspective and breaks out variations due to lease term, well spacing, and the landowner's degree of control over investment timing. The left section reports the value of the lease at time of issuance, which is the most the landowner may expect to receive in the form of front-end bonus payments. The center section reports the present value of the landowner's royalty income. The right section reports the total value captured by the landowner assuming that he receives only 5% of the full value of the lease at issuance in addition to royalty income. The upper panel represents a lease which mandates immediate development regardless of commerciality. The second panel represents a lease which mandates development as soon as the reserves are commercial, with no option to delay beyond that point. The third panel represents a lease with the HBP provision. The fourth panel represents a lease without the HBP provision, but which allows development any time before expiration of the primary term. The royalty rate is assumed to be 1/6, reserve value is $1.00/MCF, and development cost is $1.50/MCF. Shaded cells indicate the form of lease that maximizes lease value, royalty income, and total landowner's value for each combination of lease term and well spacing.

												5% Bonus Factor (Landowner Share of Lease Value)				
		FD: Lease Value With Forced Development					FD: Royalty Value Wth Forced Development					FD: Total Landowner Value With Forced Development				
	Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term	1	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
	2	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
	3	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
	4	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
	5	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
	6	-$12,500	-$6,250	-$3,125	-$1,563	-$781	$7,813	$3,906	$1,953	$977	$488	-$4,688	-$2,344	-$1,172	-$586	-$293
		ECD: Lease Value With Express Covenant if Commercial					ECD: Royalty Value With Express Covenant if Commercial					ECD: Total Landowner Value W/ Express Cov. if Comm.				
	Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term	1	$0	$0	$0	$0	$0	$3,262	$1,631	$815	$408	$204	$3,262	$1,631	$815	$408	$204
	2	$0	$0	$0	$0	$0	$5,284	$2,642	$1,321	$660	$330	$5,284	$2,642	$1,321	$660	$330
	3	$0	$0	$0	$0	$0	$5,467	$2,733	$1,367	$683	$342	$5,467	$2,733	$1,367	$683	$342
	4	$0	$0	$0	$0	$0	$5,612	$2,806	$1,403	$701	$351	$5,612	$2,806	$1,403	$701	$351
	5	$0	$0	$0	$0	$0	$6,455	$3,227	$1,614	$807	$403	$6,455	$3,227	$1,614	$807	$403
	6	$0	$0	$0	$0	$0	$6,527	$3,263	$1,632	$816	$408	$6,527	$3,263	$1,632	$816	$408
		HBP: Lease Value With HBP Option					HBP: Royalty Value With HBP Option					HBP: Total Landowner Value With HBP Option				
	Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term	1	$3,368	$1,553	$679	$286	$115	$3,313	$1,557	$673	$369	$145	$3,482	$1,634	$707	$384	$150
	2	$6,081	$2,844	$1,301	$566	$232	$4,369	$2,239	$1,030	$434	$237	$4,673	$2,381	$1,096	$463	$249
	3	$8,134	$3,860	$1,774	$775	$336	$4,874	$2,370	$1,095	$580	$251	$5,281	$2,563	$1,183	$619	$268
	4	$9,730	$4,637	$2,140	$958	$419	$5,077	$2,470	$1,145	$603	$263	$5,564	$2,702	$1,252	$651	$284
	5	$10,996	$5,258	$2,436	$1,108	$489	$5,240	$2,552	$1,187	$623	$273	$5,790	$2,815	$1,308	$678	$297
	6	$12,026	$5,767	$2,681	$1,234	$549	$5,378	$2,623	$1,224	$638	$282	$5,979	$2,911	$1,358	$700	$309
		ICD: Lease Value Without HBP Option										ICD: Total Landowner Value Without HBP Option				
	Spacing:	40	80	160	320	640	40	80	160	320	640	40	80	160	320	640
Lease Term	1	$1,841	$921	$460	$230	$115	$2,314	$1,157	$578	$289	$145	$2,406	$1,203	$601	$301	$150
	2	$3,706	$1,853	$927	$463	$232	$3,791	$1,896	$948	$474	$237	$3,977	$1,988	$994	$497	$249
	3	$5,372	$2,686	$1,343	$671	$336	$4,022	$2,011	$1,005	$503	$251	$4,290	$2,145	$1,073	$536	$268
	4	$6,706	$3,353	$1,676	$838	$419	$4,207	$2,104	$1,052	$526	$263	$4,543	$2,271	$1,136	$568	$284
	5	$7,821	$3,910	$1,955	$978	$489	$4,365	$2,182	$1,091	$546	$273	$4,756	$2,378	$1,189	$595	$297
	6	$8,777	$4,388	$2,194	$1,097	$549	$4,508	$2,254	$1,127	$564	$282	$4,947	$2,473	$1,237	$618	$309

Table 7: Impact of Landowner's Bargaining Power On Preference for HBP Provision

The table shows the minimum bargaining power necessary for the landowner to prefer the lease with the HBP provision to the lease that mandates development as soon as reserves are commercial. Bargaining power is defined as the percentage of full lease value received at issuance by the landowner in the form of bonus payment. The table shows that as long as the landowner can bargain for 25% of the value of the lease, he would generally favor including the HBP in the lease instead of a provision that mandates early development.

		Landowner Prefers HBP to ECD Lease If Bargaining Power Is At Least:				
Spacing:		40	80	160	320	640
Lease Term	1	0%	5%	21%	13%	51%
	2	15%	14%	22%	40%	40%
	3	7%	9%	15%	13%	27%
	4	5%	7%	12%	10%	21%
	5	11%	13%	18%	17%	27%
	6	10%	11%	15%	14%	23%

Table 8: Characteristics of Major U.S. Shale Gas Basins

The table shows average characteristics of the five major dry shale-gas basins in the U.S., based on EIA (2011) estimates that have been updated using proprietary data provided by a major energy-focused investment bank. Within each basin, there is substantial variation (not shown in this table) around the average formation depth, well spacing, well cost, and expected ultimate recovery (EUR) per well.

Basin	Area (sq. mi.)	Shale Depth (feet)	Well Spacing (acres)	Well Cost (million)	Avg. EUR (BCF/well)
Barnett	6,459	7,500	128	$3.0	1.93
Fayetteville	9,000	4,000	80	$2.5	2.26
Haynesville	9,000	12,000	80	$8.0	4.09
Marcellus	94,893	6,750	80	$6.0	8.13
Woodford-Arkoma	2,900	9,500	160	$5.1	3.06

Table 9: Distribution of EUR per Well, by Sub-Area, Within Each Basin

The table shows the probability distribution of expected ultimate recovery (EUR) per well for wells located respectively in the best, average, and below-average areas of each major basin. For each sub-area of a basin, the average EUR per well is reported for the top 10% of drilling locations, followed by the next 20%, the next 30%, and finally the bottom 40% of all drilling sites located within the given sub-area. The distributions are adapted from the distributions reported by EIA (2011) on the basis of proprietary EUR data provided by a major energy-focused investment bank.

Distributions of EUR, by Area	BCF/well				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	5.130	3.841	2.565	1.276	2.561
b. Average Area	3.853	2.890	1.927	0.963	1.927
c. Below Average Area	2.890	2.168	1.445	0.723	1.445
Fayetteville					
a. Best Area	8.827	4.433	2.946	0.887	3.008
b. Average Area	6.640	3.330	2.217	0.670	2.263
c. Below Average Area	4.985	2.502	1.665	0.502	1.699
Woodford-Arkoma					
a. Best Area	11.940	5.985	3.990	1.200	4.068
b. Average Area	8.978	4.500	3.000	0.900	3.058
c. Below Average Area	6.735	3.375	2.250	0.675	2.294
Haynesville					
a. Best Area	10.888	8.168	5.447	2.720	5.445
b. Average Area	8.187	6.140	4.093	2.047	4.093
c. Below Average Area	6.140	4.603	3.073	1.537	3.071
Marcellus					
a. Best Area	21.635	16.220	10.829	5.414	10.822
b. Average Area	16.267	12.200	8.133	4.067	8.133
c. Below Average Area	12.200	9.156	6.112	3.044	6.102

Table 10: Distribution of Development Cost, by Sub-Area, Within Each Basin

The table shows the probability distribution of unit development cost for wells located respectively in the best, average, and below-average areas of each major basin. For each sub-area of a basin, unit development cost is computed as 125% of well cost divided by the sub-area specific EUR per well. Well costs are as reported in Table 8. EUR estimates are as reported in Table 9. Well costs are inflated by 25% to allow for on-site costs in addition to drilling expenditures. Shaded cells indicate sub-areas within each basin that are under water when reserve price is $1/MCF.

Distributions of Development Cost, by Area

	$/MCF				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	$0.73	$0.98	$1.46	$2.94	$1.88
b. Average Area	$0.97	$1.30	$1.95	$3.89	$2.50
c. Below Average Area	$1.30	$1.73	$2.60	$5.19	$3.33
Fayetteville					
a. Best Area	$0.35	$0.70	$1.06	$3.52	$1.90
b. Average Area	$0.47	$0.94	$1.41	$4.66	$2.52
c. Below Average Area	$0.63	$1.25	$1.88	$6.22	$3.36
Woodford-Arkoma					
a. Best Area	$0.53	$1.07	$1.60	$5.31	$2.87
b. Average Area	$0.71	$1.42	$2.13	$7.08	$3.83
c. Below Average Area	$0.95	$1.89	$2.83	$9.44	$5.10
Haynesville					
a. Best Area	$0.92	$1.22	$1.84	$3.68	$2.36
b. Average Area	$1.22	$1.63	$2.44	$4.89	$3.14
c. Below Average Area	$1.63	$2.17	$3.25	$6.51	$4.18
Marcellus					
a. Best Area	$0.35	$0.46	$0.69	$1.39	$0.89
b. Average Area	$0.46	$0.61	$0.92	$1.84	$1.18
c. Below Average Area	$0.61	$0.82	$1.23	$2.46	$1.58

Table 11: Distribution of Lease Values, by Sub-Area, Within Each Basin

The table shows the estimated value of a three-year, 640-acre lease with the HBP provision located respectively in the best, average, and below-average areas of each major basin. For each sub-area of a basin, well spacing is as indicated in Table 8, EUR is given by Table 9, and unit development cost is given by Table 10. In all cases, the value of reserves is assumed to be $1/MCF. In addition, we assume the volatility of reserve value is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equation (5) of the text.

Distributions of Lease Value, by Area					
	$/acre				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	20,197	12,562	5,966	1,266	6,829
b. Average Area	12,631	7,545	3,335	616	4,019
c. Below Average Area	7,545	4,276	1,747	273	2,243
Fayetteville					
a. Best Area	77,043	29,122	15,028	1,206	18,519
b. Average Area	52,436	18,465	9,056	563	11,879
c. Below Average Area	34,676	11,223	5,163	249	7,361
Woodford-Arkoma					
a. Best Area	43,921	14,408	6,630	300	9,383
b. Average Area	28,457	8,416	3,595	120	5,655
c. Below Average Area	17,654	4,608	1,796	43	3,243
Haynesville					
a. Best Area	61,168	37,147	17,241	3,508	20,122
b. Average Area	37,292	21,744	9,235	1,578	11,480
c. Below Average Area	21,744	12,142	4,708	674	6,285
Marcellus					
a. Best Area	190,070	128,941	71,799	22,443	75,312
b. Average Area	129,453	85,605	45,580	12,820	48,868
c. Below Average Area	85,605	55,025	27,753	6,812	30,616

Table A1: Ratio of Lease Values With and Without the HBP Provision, by Sub-Area and Quantile

The table shows, for each quantile of each sub-area within each major shale-gas basin, the value of a three-year, 640-acre lease with the HBP provision relative to the value of a comparable lease that lacks the HBP provision. Well spacing is as in Table 8, EUR as in Table 9, and unit development cost as in Table 10. For all cases, we assume the value of reserves is $1/MCF, the volatility of reserve value is 50%, the real interest rate is 2%, and the convenience yield is 1%. The reported values are derived from Equations (4) and (5) of the text.

Distributions of Ratio of Lease Value With HBP Provision to Lease Value Without HBP					
	$/MCF				
	10%	20%	30%	40%	Average
Barnett					
a. Best Area	114%	121%	134%	171%	144%
b. Average Area	121%	131%	148%	199%	162%
c. Below Average Area	131%	146%	168%	242%	190%
Fayetteville					
a. Best Area	104%	115%	128%	222%	161%
b. Average Area	108%	124%	140%	269%	185%
c. Below Average Area	113%	135%	158%	322%	215%
Woodford-Arkoma					
a. Best Area	108%	121%	136%	210%	160%
b. Average Area	112%	129%	147%	268%	188%
c. Below Average Area	118%	140%	160%	355%	230%
Haynesville					
a. Best Area	123%	135%	156%	225%	176%
b. Average Area	135%	150%	181%	278%	209%
c. Below Average Area	150%	168%	211%	342%	249%
Marcellus					
a. Best Area	104%	108%	115%	139%	122%
b. Average Area	108%	113%	123%	157%	133%
c. Below Average Area	113%	120%	135%	182%	149%

Table A2: Probability that HBP Option Stimulates or Suppresses Development, by Sub-Area and Quantile

For leases located in each quantile of each sub-area within each major shale-gas basin, the table reports the probability that the HBP option will be exercised during the *last period* of the primary term, thereby affecting the scope and timing of development. Lines with "Drilling Impact" indicated by "-" show the probability that the operator will drill a single well on the lease instead of undertaking full development. Lines with "Drilling Impact" indicated by "+" show the probability the operator will drill a single sub-marginal well on the lease as opposed to letting the lease lapse. Well spacing is as in Table 8, EUR is as in Table 9, and unit development cost is as in Table 10. In all cases the primary term is assumed to be three years, the value of reserves is $1/MCF, the volatility of reserve price is 50%, the real interest rate is 2% and the convenience yield is 1%. Probabilities are calculated by the method illustrated in Figures 2 and 3, using a 25-step lattice. Therefore, the probability of development impacts shown in the table pertain to the final 45 days of the assumed three-year term. The probabilities shown here *do not include* the additional impact of earlier drilling deferrals, as indicated in Figures 2 and 3.

Probabilities of Impacting Drilling During Last Period of Primary Term

Basin		Drilling Impact	Top 10%	Next 20%	Next 30%	Bottom 40%	Average
Barnett	Best Area	-	47.7%	33.6%	20.9%	5.4%	20.9%
		+	15.6%	31.1%	13.2%	6.0%	13.2%
	Average Area	-	33.6%	20.9%	11.4%	2.2%	11.4%
		+	31.1%	28.7%	22.9%	9.3%	22.9%
	Below Average Area	-	20.9%	11.3%	5.4%	0.8%	5.4%
		+	28.7%	22.9%	15.7%	4.7%	15.7%
Fayetteville	Best Area	-	67.4%	47.7%	33.6%	2.2%	33.6%
		+	15.9%	29.0%	31.1%	9.3%	31.1%
	Average Area	-	60.0%	33.6%	20.9%	2.2%	20.9%
		+	23.2%	31.1%	28.7%	9.3%	28.7%
	Below Average Area	-	47.7%	20.4%	11.4%	0.8%	11.4%
		+	29.0%	28.7%	22.9%	4.7%	22.9%
Woodford	Best Area	-	60.0%	33.6%	20.9%	0.8%	20.9%
		+	13.4%	15.5%	13.2%	4.7%	13.2%
	Average Area	-	47.7%	20.9%	11.4%	0.2%	11.4%
		+	15.6%	13.2%	9.7%	2.0%	9.7%
	Below Average Area	-	33.6%	11.4%	5.4%	0.2%	5.4%
		+	31.1%	22.9%	6.0%	0.6%	6.0%
Haynesville	Best Area	-	33.6%	20.4%	11.4%	2.2%	11.4%
		+	31.1%	28.7%	22.9%	9.3%	22.9%
	Average Area	-	20.4%	20.9%	5.4%	0.8%	5.4%
		+	28.7%	28.7%	15.7%	4.7%	15.7%
	Below Average Area	-	20.9%	11.4%	5.4%	0.8%	5.4%
		+	28.7%	22.9%	15.7%	4.7%	15.7%
Marcellus	Best Area	-	67.4%	60.0%	47.7%	20.9%	47.7%
		+	15.9%	23.2%	29.0%	28.7%	29.0%
	Average Area	-	60.0%	44.4%	33.6%	11.4%	33.6%
		+	23.2%	29.0%	31.1%	22.9%	31.1%
	Below Average Area	-	44.4%	47.7%	20.4%	5.4%	20.4%
		+	29.0%	29.0%	28.7%	15.7%	28.7%

Figure A1: Probability that HBP Option Stimulates or Suppresses Development, by Sub-Area and Quantile

For leases located in each quantile of each sub-area within each major shale-gas basin, the figure shows the probability that the HBP option will be exercised during the *last period* of the primary term, thereby affecting the scope and timing of development. Blue bars represent the probability that the operator will drill a single well on the lease instead of undertaking full development. White bars show the probability the operator will drill a single sub-marginal well on the lease as opposed to letting the lease lapse. Well spacing is as in Table 8, EUR is as in Table 9, and unit development cost is as in Table 10. In all cases the primary term is assumed to be three years, the value of reserves is $1/MCF, the volatility of reserve price is 50%, the real interest rate is 2% and the convenience yield is 1%. Probabilities are calculated by the method illustrated in Figures 2 and 3, using a 25-step lattice. Therefore, the probability of development impacts shown in these figures pertain to the final 45 days of the assumed three-year term. The probabilities shown here *do not include* the additional impact of earlier drilling deferrals, as indicated in Figures 2 and 3.