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Exploration and development of U.S. oil and gas fields, 1955–2002

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ABSTRACT

We study the exploration and development of oil and gas fields in the U.S. over the period 1955–2002. We make four contributions to explain the economic evolution of the oil and gas industry during this period. First, we derive a testable model of the dynamics of competitive oil and gas field exploration and development. Second, we show how to empirically distinguish Hotelling scarcity effects from effects due to technological change. Third, we test these hypotheses using statewide panel data of exploration and development drilling. We find that the time paths of exploration, development and total wells drilled are dominated by Hotelling scarcity effects. Finally, we offer an explanation for why fixed costs from exploration can make the contracting equilibrium in the mineral rights market efficient.

1. Introduction

Between 1859, when crude oil production began, and 1954, the U.S. was both the largest producer and discoverer of oil in the world, as well as a net exporter of oil. By 1955, the U.S. had discovered 82 billion barrels of oil (35.8% of world discoveries), had produced 48 billion barrels (60.3% of world production), held 29 billion barrels of oil reserves (21.7% of world reserves), 198 trillion cubic feet of natural gas reserves, and had drilled 1.54 million oil and gas wells, accounting for 92.7% of world producing oil wells at the end of 1954. During the period between 1955 and 2002, the U.S. oil and gas industry drilled an additional 2 million wells and discovered an additional 122 billion barrels of oil and 794 trillion cubic feet of new natural gas. But the rest of the world was quickly catching up. Between 1955 and 2002, the U.S. became a net importer of 73 billion barrels of crude oil (35% of domestic consumption). By 2002, the U.S. would account for only 8.8% of world oil production, 1.6% of world proved reserves, 10.7% of cumulative discoveries, and 20.3% of cumulative world oil production.

A crucial institutional difference between the U.S. and the rest of the world is that mineral rights are owned mainly by individuals in the U.S., while elsewhere they are mainly owned by the state.[2] Thus, contracting for oil and gas mineral rights in the U.S. can involve multiple mineral rights owners as well as multiple exploration and development firms. While the U.S. accounted for only 8.8% of world production at the end of 2002, it accounted for 59% of producing wells. This has led a number of authors to argue that the U.S. oil and gas industry has dissipated a significant proportion of the economic rents.[3] If true, this would be one of the largest bills on the sidewalk ever left unclaimed.

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[2] Even in the U.S., the federal government owns mineral rights on federal lands and states own mineral rights on riparian zones and three miles out into the ocean.

[3] Bain (1947), Libecap and Wiggins (1984, 1985), Smith (1987), Libecap and Smith (1999, 2001, 2002), and Yuan (2002), *inter alia*, have argued that contractual failures have occurred in the U.S. over how to allocate production on crude oil or natural gas fields.

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However, the following example from the 71,000 acre Slaughter field in west Texas suggests the rent dissipation may have been small. An attempt to resolve the common pool problem by unitizing production failed, but 28 subunits were created. By 1975, to prevent migration of oil across subunits, 427 injection wells had been drilled along the boundaries of the subunits at a total cost of 156 million dollars (Libecap and Wiggins, 1985, p. 694). A back-of-the-envelope calculation, using the average production rate of 18 million barrels per year with observed prices over 1936–2007, yields a present value (at 4% real interest rate) of 9 billion 2007 dollars of oil revenues on the field. Using Libecap and Wiggins' estimate of drilling costs, the total drilling cost of the 3000 wells drilled on the field equals 4 billion 2007 dollars. Thus the field appears to have generated 5 billion 2007 dollars in net revenues for its owners. Thus, the dissipation of rents by the 427 injection wells on the subunit boundaries amounted to only 3% of net returns.[4]

The purpose of this paper is to derive and test an economic model of contracting by producers for exploration and development of oil and gas fields. As industry data are available which distinguishes between exploratory wells (i.e., wells drilled whose purpose is finding new reserves) and development wells (i.e., wells drilled for the purpose of production on a known field), we develop hypotheses about how the rates of exploration and development drilling vary over time. While there have been several previous models of exploration and of production taken separately, little attention has been focused on the economics of exploration and development taken together.[5] Given the interdependence between exploration and development, and the availability of data with which to test hypotheses, this is an important gap in the literature.

We make four contributions towards understanding the economics of exploration and development of oil and gas fields. First, we derive a model of the dynamics of competitive oil and gas field exploration and development. Following Libecap and Wiggins (1985) and Wiggins and Libecap (1985), in a market with well-defined property rights, producers pay mineral rents to mineral rights owners *prior* to exploration rather than at the time of development. The mineral rent price must rise over time in order to compensate mineral rights owners for their opportunity cost of waiting to allow their minerals to be developed later (Hotelling, 1931). But since producers pay mineral rents before they begin exploration, these costs are *sunk* by the time a discovery is made and development drilling begins. As production can be increased either by finding new fields or more intensively developing existing fields, we predict that firms substitute from exploratory drilling to development drilling over time in response to rising scarcity rental price, all else constant. As substitution between types of drilling is imperfect, total drilling also declines over time. This is a novel test of Hotelling's hypothesis.[6]

Our second contribution is to distinguish the dynamic effects of Hotelling scarcity rents from the dynamic effects due to technological change. Recovery methods have dramatically improved since oil production began in the 1860s. In the early 1900s, the inflow of water into an oil field heralded a catastrophic demise in the field's productivity.[7] However, by the 1950s,water was routinely being injected into fields to increase the natural hydraulic pressure in the field. The injection of steam, natural gas, and other chemical processes came to be used to enhance recovery. These increased the recoverable reserves from an oil field from less than 30% percent to over 60%.[8] There has also been dramatic technological change in the drilling process itself. While the Pennsylvania fields of the 1860s were less than 100 ft in depth, modern rotary drilling methods allowed geologists to dig much deeper for oil. As oil is generally found between 5000 and 15,000 ft in depth—gas is found deeper—these advances in drilling technology have made more reserves accessible. Furthermore, while offshore drilling had occurred on the shallow continental shelf on the coasts of Louisiana and California since the early 1900s,advances in drilling technology made possible drilling in the deeper waters of the Gulf of Mexico and in the Arctic. We find that increases in the recoverable reserves found per field and decreases in the costs of drilling each cause firms to substitute from development drilling towards exploratory drilling, effects which are opposite to Hotelling scarcity effects.

Our third contribution is to empirically test our theory of exploration and development drilling using a panel of U.S. states data over the period 1955–2002. We distinguish between the predicted time trends of exploration and development when Hotelling scarcity effects dominate and when technological effects dominate. Since the technological change effects could dominate even if property rights were well defined, and since Hotelling scarcity effects can dominate only when the scarcity effects are large enough to offset the technological change effects, our test is biased against finding these effects. However, we find evidence that the number of development wells per new field is rising over time and the number of exploratory wells and total wells drilled is falling over time, all else constant. We conclude that the time paths of exploration, development and total wells drilled are driven by rising scarcity rental prices.

[4] Production and wells drilled data are from ''U.S. Fields with Ultimate Oil Recovery Exceeding 100 Million BBL'', *Oil and Gas Journal*, January 26, 1998, p. 82, updated using the Texas Railroad Commission's ''General Production Query'', http://webapps.rrc.state.tx.us/PDQ/home.do.

[5] Production models stemming from Hotelling (1931) assume a fixed stock, and hence ignore the distinction between exploration and development altogether. Exploration models such as Arrow and Chang (1982) and Mendelsohn and Swierzbinski (1989) solve for equilibrium rates of exploration and production, but production in their model does not require investment in development drilling. Libecap and Wiggins (1985) and Wiggins and Libecap (1985) distinguish exploration from development drilling, but their purpose is to explain how contracting between producers differs at each stage, not to solve for the equilibrium level of either type of drilling.

[6] Chermak and Patrick (2002) summarize the literature on testing the Hotelling prediction. Barnett and Morse (1963), Smith (1979), and Slade (1982), *inter alia*, examined Hotelling effects using prices. Miller and Upton (1985) used stock market data, Halversen and Smith (1984, 1991), Slade and Thille (1997), Chermak and Patrick (1995, 2001, 2002), and Black and LaFrance (1998) test for Hotelling effects using production to measure costs.

[7] See Nind (1964), Interstate Oil Compact Commission (1974), Harbaugh et al. (1977), and Green and Willhite (1998) for discussions of technological changes in recovery and drilling technologies.

[8] Some estimates suggest about half of production in the U.S. uses enhanced recovery methods (Green and Willhite, 1998).

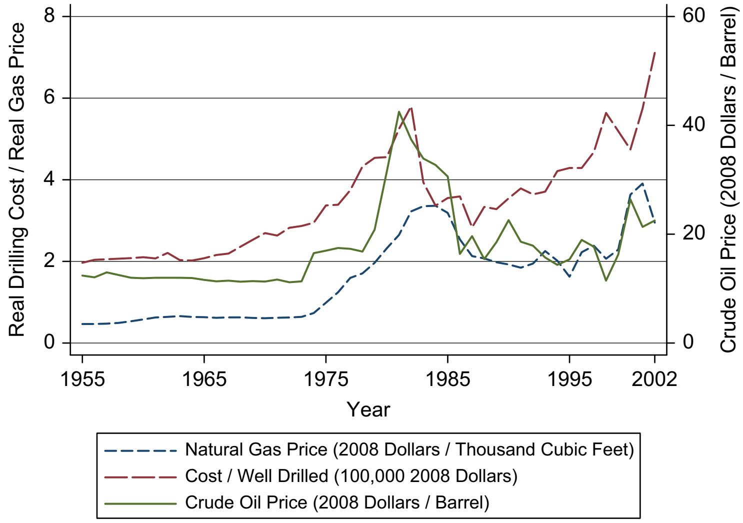

Fig. 1. Real crude oil and natural gas prices and U.S. real average on-shore drilling costs (2008 Dollars), 1955–2002.

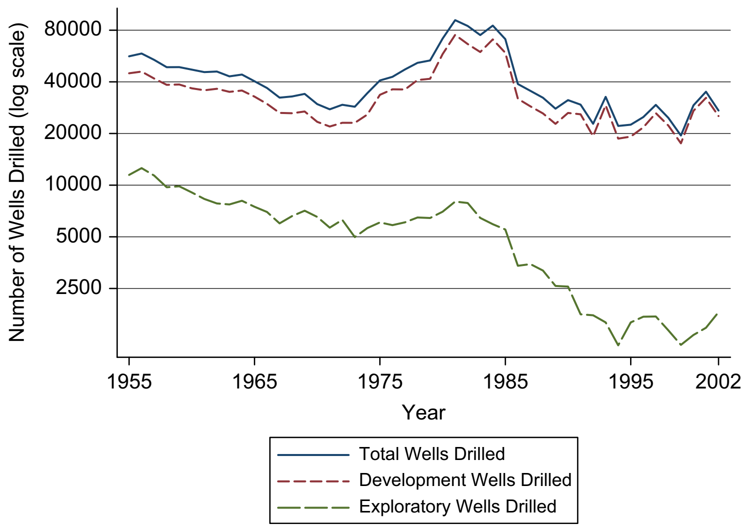

Fig. 2. Number of total wells drilled, development wells drilled, and exploratory wells drilled, U.S. total, 1955–2002 (log scale).

Our final contribution is to provide an explanation as to why the contracting equilibrium between producing firms and landowners has done a good job at preserving economic rents. Exploration expenditures must be made prior to knowing whether or not oil or gas exists in a particular area. As such, these costs are unavoidable *fixed costs* in the development of a field. When other firms are able to observe the results of an exploratory well and if there is free entry into exploration and development, we show that no contracting equilibrium exists in which some firms pay the fixed costs of exploration while others do not. Thus in the presence of unavoidable fixed costs of exploration, in the Nash equilibrium we expect to see that fields are developed by a single firm—which is the efficient outcome with a common property resource.[9]

2. Stylized facts

To focus the discussion, we begin by presenting the main stylized facts that we believe a model of oil and gas exploration and development must be able to explain.

[9] Similarly, Libecap and Smith (2002, p. S595), argue that unitization is more likely to succeed when a field requires enhanced (secondary or tertiary) methods to maintain production because all producers benefit from the (fixed) cost incurred by the producer who converts his well into an injection well to create pressure in the field.

Table 1
Descriptive statistics by state and U.S. total, 1955–2002.

State	Total wells drilled	Exploratory wells drilled	Development wells drilled per new filed	Exploratory success rate (%)	Development success rate (%)	Real average cost ($1000)	Crude oil reserves/ exploratory well (m. bbl.)	Natural gas reserves/ exploratory well (m. cft.)	Off-shore exploratory (%)	Federal land (%)
Alabama	214.8	46.4	34.4	14.9	73.7	668.8	0.37	5.73	0	3.41
Alaska	114	10.7	54.4	15	93.5	4,476	44.88	59.54	5.22	86.18
Arizona	11.2	7	5	5	44.5	1,255	–	–	0	44.58
Arkansas	468.8	78.1	69.4	9.1	66	273.2	0.18	3.24	0	9.48
California	2316	147.3	464.3	7	92.7	314.6	2.24	2.03	1.85	45.36
Colorado	1036	281	32.6	13	73.2	294.2	0.1	3.07	0	35.97
Florida	21	10.2	13.1	3.7	64.6	1871	2.23	2.9	0	10.15
Illinois	1418	197.6	232.5	4.7	65.3	82.2	0.14	0.13	0	1.68
Indiana	480.3	91	89.3	10.3	58.5	52.7	0.05	0	0	1.97
Kansas	3668	496	52	15	66.6	116.4	0.08	0.5	0	1.19
Kentucky	1426	89.1	188	14.9	62.7	72.4	0.33	5.39	0	4.93
Louisiana	3307	452.9	94	9.4	69.1	1413	1.31	13.36	29.75	3.7
Michigan	595.3	184.9	38	14.6	68.3	241.6	0.11	2.87	0	9.97
Mississippi	461.6	182.8	20.9	11.2	56	653.8	0.26	0.84	0	5.27
Missouri	47.6	7.3	23.3	10.7	72.3	154.3	–	–	0	4.78
Montana	528.2	184.9	21.1	15	72.3	271.2	0.18	0.4	0	29.25
Nebraska	344.9	170.5	12	9.8	56.9	146.7	0.06	0.02	0	2.04
Nevada	16.2	10.1	4.2	3.5	64.9	209.6	–	–	0	85.55
New Mexico	1376	142	63.2	27.8	88.3	428.3	0.56	8.71	0	33.74
New York	269	12.2	93.6	29.9	91.8	143.1	0.06	2.63	0	0.79
North Dakota	273.9	84.9	18.5	18.2	73.7	655.4	0.36	0.48	0	4.41
Ohio	1826	38.7	564.1	27.3	85.3	143.1	0.17	2.74	0	1.2
Oklahoma	4600	262.6	101.7	23.7	73.3	388.9	0.4	6.08	0	2.97
Oregon	7.2	2.4	9.2	3.9	59.2	122.7	–	–	–	52.15
Pennsylvania	1344	15.7	450.8	34.9	93.4	143.1	0.47	11.15	0	2.23
South Dakota	28.2	17	9.6	5.5	75.1	153.1	–	–	0	6.44
Tennessee	161	49	19.2	28.8	54.5	153.1	–	–	0	6.28
Texas	13,188	1899	45.3	17.9	79.6	444.2	0.32	2.79	2.638	1.77
Utah	257.5	54.4	32.7	19.2	83	827.8	0.55	4.76	0	64.97
Virginia	83.4	2.5	71.9	39.2	91.1	160	–	26.19	0	8.88
West Virginia	987.1	15.6	299.4	40.6	92	143.1	0.09	42.75	0	7.07
Wyoming	1324	284.2	31.6	15.3	76.9	537.8	0.34	4.07	0	48.69
United States	42,033	5514	115.4	16.1	73.4	551.6	0.34	3.07	1.19	17

Notes: Reported statistics are the average for each state over the period 1955–2002. In the row titled 'United States', the first two columns are the sums over all states of the number of wells drilled, while the remaining columns are the un-weighted averages across states. '–' indicates data disaggregated by state are not available.

Fig. 1 shows the trends from 1955 to 2002 in real crude oil and natural gas prices and the average cost per well drilled in the U.S.[10] Fig. 2 plots the number wells drilled, in total, and by development and exploration in the U.S. over this period. The real oil price and the total number of wells drilled in the U.S. are highly correlated (r=0.67). Thus exploration and development drilling are responsive to exogenous changes in prices. The rise in the number of wells drilled during the price spike in the early 1980s was associated with a rise in drilling costs. Thus drilling costs are also increasing in the rate of drilling.[11] In addition, average drilling costs have continued to rise from about 1985 forward, in spite of a leveling off of the number of wells drilled. This is because the industry has expanded to more expensive areas to drill such as the Gulf of Mexico, Alaska, and the Rocky Mountain region. Finally, while there is a downward trend in all types of drilling, the number of exploratory wells drilled has been declining more rapidly than has other types of drilling.

Table 1 contains the summary statistics of relevant data by state for the entire 1955–2002 period. Texas leads all states in wells drilled, accounting for 31% of all wells drilled in the U.S. In their study of unitization agreements, Libecap and Wiggins (1985) found that Texas requires unanimous agreement to unitize production on a field, while Oklahoma permitted "63% of

[10] A description of the data sources and construction is in Appendix A.

[11] Norgaard and Leu (1986) also found a positive correlation between drilling costs and the level of drilling using U.S. drilling data from 1959 to 1978. Corts (2008) found that the dayrate (rental price) for an offshore rig varied from $43,000 in June 1998 to $14,000 in June 1999 to $34,000 in 2000. He attributes this high variance to fluctuating demand conditions in the presence of capacity constraints for rig suppliers.

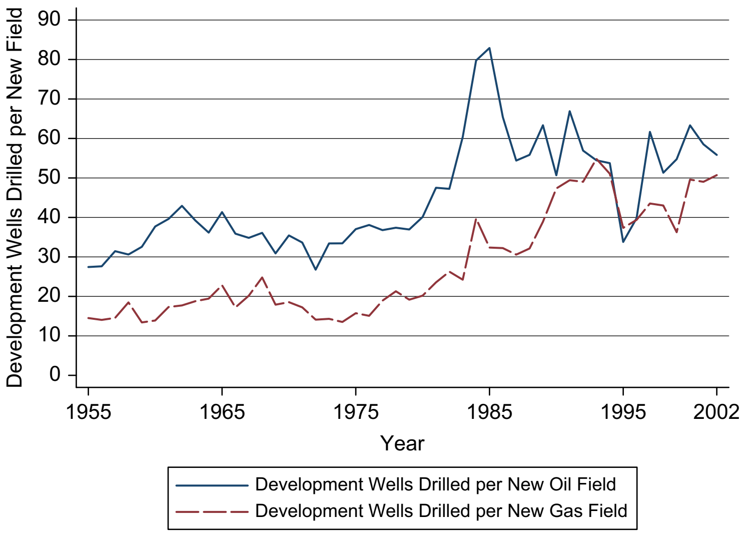

Fig. 3. Number of development wells drilled per new field by oil and gas, U.S. average, 1955–2002.

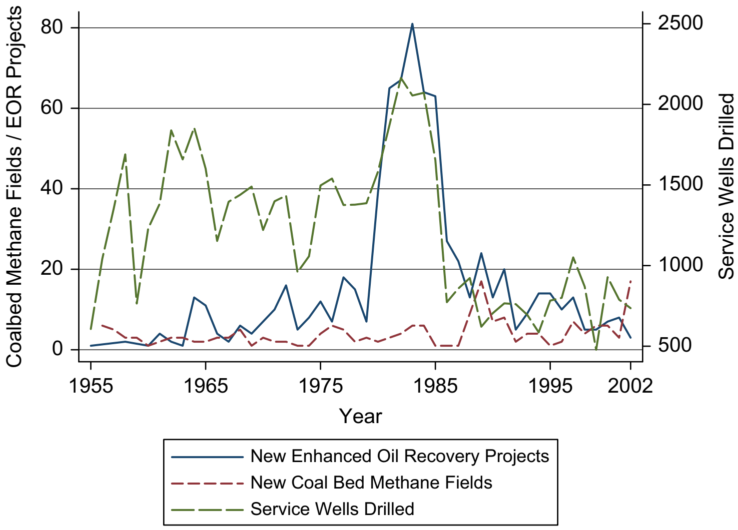

Fig. 4. Number of new coal bed methane fields, new enhanced oil recovery projects, and service wells drilled, U.S. total, 1955–2002.

the parties to coerce the other firms to join a unit" (p. 632), and Wyoming, which is almost 50% federal land, required unitization agreements to be reached prior to exploration, in contrast to both Texas and Oklahoma. Libecap and Wiggins argued this was why unitization rates through 1975 were lowest in Texas (22%), followed by Oklahoma (38%), and highest in Wyoming (82%). This might be thought to explain why Texas leads in total drilling and why Wyoming has relatively higher proportions of exploratory to total wells drilled (21%) than Texas (14%). However, Texas has only slightly more development wells drilled per new field than the U.S. average (and Wyoming only slightly less than the U.S. average), and Texas accounts for an even larger share (34%) of U.S. exploratory drilling than of total wells drilled. It is difficult to reconcile the high level of exploratory drilling with claims higher than average rent-dissipation in Texas, especially given that Texas fields are no larger than the national average.

Table 1 also shows that the number of wells per new field is much higher in Ohio, Pennsylvania, Illinois and California than elsewhere. In part this is because some of the drilling is "infill" drilling, where new wells are drilled on existing fields. It is also in part due to differences in the nature of oil and gas fields. California, for example, has very heavy oil, which requires higher density of wells to extract. Hence, well-spacing regulations in California require only that wells be 150 ft from other wells. This is considerably lower than the 600 foot minimum well spacing in Oklahoma, Ohio, and Kansas, and the 1200 foot minimum distance required in Texas.

Fig. 3 shows that the number of development wells per new field has been rising for both oil and gas fields. Our hypothesis is that this is due to rising scarcity rental costs which reduce the relative costs of drilling development wells. However, this

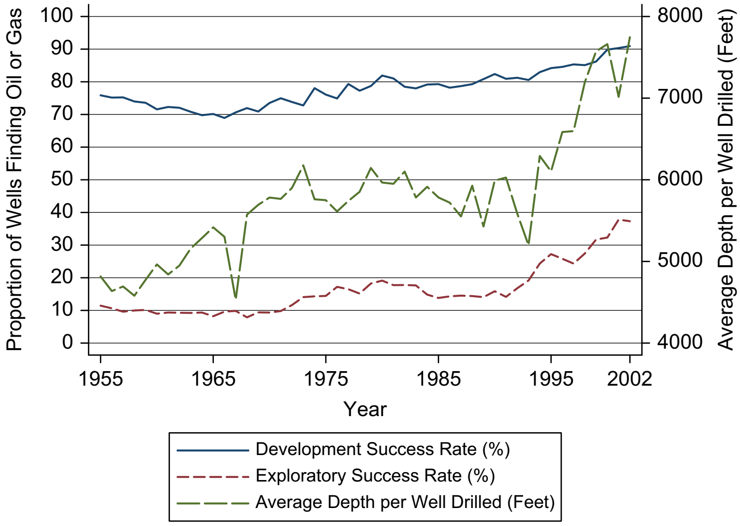

Fig. 5. Development and exploratory drilling success rates and average depth, U.S. average, 1955–2002.

result could be due to higher density of wells because of lower permeability of fields (such as coal bed methane) or due to infill drilling on existing fields. To investigate this, Fig. 4 presents the time paths of enhanced oil recovery projects, coal bed methane fields discovered, and service wells drilled. The number of enhanced oil recovery projects and the number of service wells drilled are each likely to be correlated with "infill" drilling. Coal bed methane gas fields require higher density of wells than other gas fields. However, none of these variables appear to be highly correlated with the number of development wells drilled per new field ($r<0.4$ for all three variables), although the total wells drilled is highly correlated with both enhanced oil recovery projects (r=0.72) and service wells drilled (r=0.70).

Finally, Fig. 5 presents evidence about technological change. In 1955, about 12% of exploratory wells and about 60% of development wells were successful in finding oil or gas. However, by 2002, nearly 40% of exploratory wells and nearly 80% of development wells were successful. The average depth of wells drilled also rose from less than 5000 ft to almost 8000 ft between 1955 and 2002. Thus, even though oil and gas was being found at more extreme depths, the rate of discovery was increasing as the technologies such as 3-dimensional seismic analysis became available. Interestingly, the rise in drilling costs in the early 1980s does not show up as an increase in the average depth drilled, which suggests that the rise in drilling costs was due to higher demand for drilling resources.

The model we present explains each of these stylized facts. Price taking firms facing drilling costs that increase in the rate of drilling are responsive to shocks in oil and gas prices. Thus, higher drilling costs in Fig. 1 are correlated with the positive price shocks in the 1970s and early 1980s, but are not correlated with increases in average well depth (Fig. 5) during this period. However, technological change has allowed the industry to expand the set of areas that can economically produce oil and gas, and this is correlated with the higher drilling costs and average depth of wells observed after 1985. The rise in the number of development wells per new field is explained by rising costs of exploration due to a rising Hotelling scarcity rental price, which is paid at the time exploration commences, but are sunk by the time a field is developed. Finally, the puzzle of why both exploration and development are highest in Texas, even though unitization rates are lowest in Texas, is explained by the rent-dissipation being much smaller than suggested by looking at indirect evidence from unitization rates.

3. Development of a new field

Let us now turn to the theoretical model. Development drilling occurs because production depends upon the number of development wells on the field. Let $w(t)$ denote the number of development wells drilled on a field discovered at time t. Of the $w(t)$ wells drilled, proportion $\phi \subset (0,1)$ are successful. Therefore, the number of producing wells on the field is $\phi w(t)$, which, if expectations about prices and technology are realized, remains fixed over the life of a field. Let the quantity of recoverable reserves remaining on the field at time $s \geq t$ be denoted as $R(s)$. Given the number of development wells drilled on the field, production on the field depends only upon the reserves remaining on that field (e.g., Livernois and Uhler, 1987; Mendelsohn and Swierzbinski, 1989)[12]:

$$q(s) = \phi w(t) R(s). \tag{1}$$

[12] MacAvoy and Pindyck (1973), Kuller and Cummings (1974), Black and LaFrance (1998), and Bohn and Deacon (2000) model production which depends upon inputs, other than reserves, that vary over time. However, our data does not allow us to observe these inputs, so they are neglected. Black and LaFrance (1998) find evidence that firms vary production in response to price changes. Hence, in our empirical analysis, we control for price changes to account for these effects.

Eq. (1) is the Schaefer production function often utilized in natural resource modeling. The equation of motion for crude oil reserves on the field obeys

$$\frac{dR(t)}{dt} \equiv \dot{R} = -q(t), \quad R(0) = R_0 > 0. \tag{2}$$

Holding the number of wells fixed over time implies that the stock at any instant in time $s \geq t$ is given by

$$R(s) = R_0 e^{-\phi w(t)(s-t)} \quad \text{for } s \geq t. \tag{3}$$

From (1) and (3) we can express production at time $s \geq t$ as

$$q(s|w(t)) = \phi w(t) R_0 e^{-\phi w(t)(s-t)} \quad \text{for } s \geq t. \tag{4}$$

The quantity produced at time $s \geq t$ depends on the number of development wells placed on the field at the time of discovery, w_t, the initial recoverable reserves on the field, R_0, and the distance in time since discovery, $s-t$. As in MacAvoy and Pindyck (1973), field production decreases over time at rate $\dot{q}(s)/q(s) = -\phi w(t)$, which is increasing in the number of development wells drilled.[13]

The choice of how many development wells to drill depends upon the future prices expected by producers at time t. Denote the expected price at time $s > t$ as $p^e(s)$. We suppose that the expected price at time $s > t$, given price $p(t)$, is $p^e(s) = p(t)e^{g(s-t)}$, where g is the expected rate of growth in the price, and $g < r$ is required so that firms wish to produce in the present. Given these expectations about future prices, once a field has been discovered, the present value of the field rents (ignoring exploration costs) is

$$\Pi_t = \int_t^T e^{-r(s-t)}[p^e(s)q(s|w(t)) - \phi C_o w(t)]\, ds - C_w w(t), \tag{5}$$

where T is the time at which a field discovered at time t is economically exhausted, $r > 0$ is the discount rate, C_o is operating cost per successful development well, and C_w is the drilling cost per well.

Once a well is placed on a field, it is operated so long as the additional revenues from that well exceed the cost of maintaining the well. The additional revenues from a well exceed the costs of maintenance so long as $p(T)q(T|w(t))/w(t) \geq C_o$. Thus at time T, the field operator will begin shutting down wells. Given exponential growth in $p(t)$ and $q(T|w(t))$, $C_o \to 0$ implies that $T \to \infty$. Thus the assumption that maintenance costs are negligible implies that a successful well is operated into perpetuity.[14] Therefore, we may write the stream of quasi-rents from the field as

$$V(w) \approx \int_t^\infty e^{-r(s-t)}[p^e(s)q(s|w(t))]\, ds = \frac{p(t)R_0\phi w(t)}{r - g + \phi w(t)}. \tag{6}$$

The quasi-rental value of the field depends upon the number of wells placed on the field at the time of discovery, the price at the time of discovery, the reserves in the field, and the rate of growth of the price relative to the discount rate. It follows from (6) that $V(w)$ is an increasing, concave function in the number of wells drilled on the field.

3.1. Technological change

To incorporate technological progress in recovery methods, note that field quasi-rents function, $V(w)$ given by (6), is linear in initial recoverable reserves, R_0. Thus technological progress in recovery methods is achieved by rewriting the quasi-rents from a field as $\delta V(w(t))$, where $\delta(t) \in (0,1)$ measures the proportion of reserves recoverable using the technology available at time t. Technological progress implies that $\delta(t)$ is increasing over time. Let $\dot{\delta}/\delta = g_\delta > 0$. Enhanced recovery methods typically involve a higher density of development wells. This occurs because (6) implies that $V'(w)$, the marginal product of a development well, is increasing in the size of the reserves.

To incorporate technological progress in drilling costs, recall first that Figs. 1 and 2 showed that the drilling costs were positively correlated with total number of wells drilled. The total number of wells drilled at time t is given by

$$D(t) = x(t)[1 + \theta w(t)], \tag{7}$$

where θ is the probability that an exploratory well is successful in discovering a field, and $x(t)$ is the number of exploratory wells drilled. The number of development wells drilled per field is the same for each new field discovered in period t, although $w(t)$ may vary over time. Thus, in any period, industry drilling costs are $\gamma(t)c(D(t))$, where $D(t)$ is total drilling, and the function $c(D)$ has the properties that $c'(D) > 0$ and $c''(D) > 0$. The parameter $\gamma(t)$ measures the drilling technology available at time t. Technological advances in drilling imply that $\dot{\gamma}/\gamma = -g_\gamma < 0$ is decreasing over time (Copp, 1974). In the competitive equilibrium, the marginal costs are $\gamma C_x = (1 + \theta w)\gamma c'(D)$ and $\gamma C_w = \theta x \gamma c'(D)$. For every additional exploratory well drilled, θw development wells are drilled, and an additional w development wells are drilled on each discovered field.

[13] Nind (1964, pp. 42–48) provides evidence that well production behaves like (4).

[14] The U.S. Energy Information Agency estimates that 36% of producing wells in the U.S. produced at a rate of less the one barrel of oil equivalent per day in 2002. This suggests that maintenance costs are quite low.

Lower drilling costs allow wells to be dug in areas that were previously uneconomic (Copp, 1974; Norgaard and Leu, 1986; Cuddington and Moss, 2001). Thus, in our empirical analysis below we shall control for both costs of drilling and the average depth of drilling in order to isolate the effects of technological change on the level of drilling.

3.2. "Infill" drilling

A key assumption in the derivation of the quasi-rents function $V(w)$ is that the field is developed at the instant it is discovered. This occurs because a price taking field operator faces a constant marginal cost of drilling a well, which means that in the relevant range of the field, the investment rate is unbounded (Arrow, 1968). However, this is a *ceteris paribus* result: a sufficiently large change in the correct direction of any of the parameters in (6) may result in additional wells being drilled upon the field.

When a field is discovered, the potential recoverable reserves are based on the technology at the time of discovery, $\delta(t)$. The number of wells drilled on a field with technology of vintage t is the number that equates $E[\delta(t)V'(w(t)] = \gamma(t)C_w$, where the expectation is over future prices and technologies, and the recoverable reserves depend upon the existing technology. Suppose that at time $s > t$, technological improvement allows recovery of $\delta(s) > \delta(t)$ proportion of existing reserves. Since recoverable reserves are being depleted at rate $-\phi w(t)$, the recoverable reserves on a field of vintage t and age $s-t$ is $\delta(s)R_0e^{-\phi w(t)(s-t)}$. Thus, a necessary condition for infill drilling to occur, all else constant, is that $\delta(s)/\delta(t) = e^{g_\delta(s-t)} > e^{-\phi w(t)(s-t)}$, or that the *ex post* rate of growth in technology exceeds the rate of depletion over the interval $s-t$. If the price is also rising, then the condition under which additional wells will be drilled on a field is that the rate of growth in price and technology exceeds the rate of depletion. Hence the jump in development drilling during the price boom of the early 1980s was more price driven than technology driven.

Infill drilling and new field development well drilling each depend only on the drilling costs relative to expected returns to a field. Both are independent of mineral rental price, as this cost is sunk at the time of drilling regardless of whether it is an infill well or a new field development well.

4. Contracting equilibrium

Thus far, we have established the dynamics of field development and how technological change affects field rents and drilling costs. Next, we consider how exploration costs affect the contracting between landowners and producing firms.

Exploratory drilling is necessary in order to have production, but it is not sufficient, since development wells must also be drilled. Therefore, the cost of exploration is an unavoidable fixed cost in a field's development, since, unlike development drilling costs, exploration costs do not vary with the production level.[15]

Suppose that there are N identical mineral rights owners over each potential field, and that each mineral rights owner contracts with at most one producer. All contracts are written so that a fixed transfer from the producer to the mineral rights owner occurs at the beginning of the contract, and there is no further sharing of profits.[16] There are two types of firms that may contract with mineral rights owners. *Exploratory* firms both explore and develop the field (or subcontract development), while *development* firms only develop a field once a discovery has occurred. All firms are risk neutral.

Exploration is very simple. Based on the results of drilling an exploratory well at cost γC_x, the exploratory firm is able to determine whether or not there is oil or gas under the N parcels of land. The probability that oil is discovered is θ. Once the result of this test is known to the exploratory firm it becomes common knowledge.[17]

Let π_x and π_d denote the profits earned on each lease by an exploration firm and a development firm, respectively, given that a discovery has been made. Similarly, let ψ_x and ψ_d denote the payment made to the mineral rights owner by the wildcat and development firms, respectively. Suppose that the wildcat exploration firm contracts with M of the N mineral rights owners, where $M \in \{1,2,\ldots,N\}$. Then the exploration firm's expected profits are

$$E[\Pi_x] = M(\theta\pi_x - \psi_x) - \gamma C_x. \tag{8}$$

The term $-\gamma C_x$ is the *fixed cost* of drilling the exploratory well and the term $M(\theta\pi_x - \psi_x)$ is the expected development rents, net of mineral rights acquisition costs, accruing to the exploratory firm.[18]

Denote the mineral rights owners' rents as L_x and L_d, respectively, depending upon whether they contract with an exploration firm prior to exploration or with a development firm subsequent to a successful discovery. The M mineral rights owners who contract with the exploration firm each earn ψ_x:

$$L_x = \psi_x, \quad x = 1,\ldots,M. \tag{9}$$

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[15] MacAvoy and Pindyck (1973) model investment in exploration as having a fixed component and a variable component (see their Eq. (5), p. 472), but they do consider how the fixed costs affect the contracting equilibrium.

[16] These assumptions follow Yuan (2002), except that he allows mineral rights owners to contract with more than one developer.

[17] There has been much attention in the literature on the informational spillovers from exploration (e.g., Hendricks et al., 1987; Hendricks and Kovenock, 1989; Hendricks and Porter, 1988, 1996; Lin, 2007, 2009). We choose this simple information environment because, unlike those authors, we cannot observe the location of successful wells beyond the state in which they are drilled. See Section 4.2.

[18] The contracting equilibrium below can also be obtained by assuming that the profits to the exploratory firm are written as $\Pi_x = \theta M\pi_x - (1-\theta)C_x - M\psi_x$. In this specification, a successful exploratory well is productive, but with probability $1-\theta$ the result of exploration is a dry hole with costs C_x.

In contrast, the $N-M$ mineral rights owners who choose to wait and contract with a development firm once it becomes known that a discovery has occurred (where the expectation is over exploration outcomes) earn

$$E[L_d]=\theta\psi_d, \quad d=M+1,\ldots,N. \tag{10}$$

This reflects that with probability $1-\theta$ no discovery occurs, so no development contract is written. The expected profits to a development firm are thus

$$E[\Pi_d]=\theta(\pi_d-\psi_d), \quad d=M+1,\ldots,N. \tag{11}$$

Following Yuan (2002), suppose that there is free entry into both exploration and development of crude oil fields. This implies that in equilibrium $E[\Pi_x]=0$ and $E[\Pi_d]=0$. Therefore, from (11), $\psi_d=\pi_d$ and from (8), $\psi_x=\theta\pi_x-\gamma C_x/M$. In order for a risk neutral mineral rights owner to be indifferent between writing a contract with a development firm conditional upon a discovery or writing a contract with an exploration firm prior to exploration it must be that L_x=$E[L_d]$. Hence, the equilibrium number of mineral rights owners who contract with the exploration firm must satisfy

$$M\theta(\pi_x-\pi_d)=\gamma C_x. \tag{12}$$

Therefore π_x must be greater than π_d in order for development and exploratory firms to coexist in the Nash equilibrium.

Now let us determine π_x and π_d. Holding M fixed, the total number of development wells drilled on the field if a discovery occurs is

$$w=Mw_x+(N-M)w_d, \tag{13}$$

where w_x and w_d are the Nash equilibrium choices of development wells *per lease* by the exploration firm and by the $N-M$ symmetric development firms, respectively. Thus, π_x and π_d equal

$$M\pi_x=\frac{Mw_x}{w}[\delta V(w)-\gamma C_w w], \tag{14}$$

$$\pi_d=\frac{w_d}{w}[\delta V(w)-\gamma C_w w], \quad d=M+1,\ldots,N, \tag{15}$$

where $V(w)$ is given by (6) and where δ and γ index the available recovery and drilling technology, respectively. Mw_x is the total number of development wells drilled by the exploration firm if successful at the exploration stage. The exploration firm's share of the present value of the field rents is Mw_x/w. Each development firm obtains share w_d/w of the field rents.

For a given M, the Nash equilibrium choices of numbers of development wells satisfy

$$\left(\frac{Mw_x}{w}\right)\delta V'(w)+\left(1-\frac{Mw_x}{w}\right)\frac{\delta V(w)}{w}=\gamma C_w, \tag{16}$$

$$\left(\frac{w_d}{w}\right)\delta V'(w)+\left(1-\frac{w_d}{w}\right)\frac{\delta V(w)}{w}=\gamma C_w, \quad d=1,\ldots,N-M. \tag{17}$$

Subtracting (17) from (16) yields

$$\left(\frac{w_d}{w}-\frac{Mw_x}{w}\right)\left(\frac{\delta V(w)}{w}-\delta V'(w)\right)=0,$$

which implies that

$$Mw_x=w_d. \tag{18}$$

Thus, the exploration firm places a smaller number of wells on each property for which it purchases the mineral rights than do the development firms. This occurs because the exploration firm internalizes the externality it imposes on its other $M-1$ leases, while the development firms hold only one lease, so they internalize none of the external costs they impose on other lease-holders.

Given the equilibrium values of w_d and w_x from (18), the equilibrium values of π_x and π_d in (14) and (15) satisfy

$$M\pi_x=\pi_d=\left(\frac{w_d}{w}\right)[\delta V(w)-\gamma C_w w]. \tag{19}$$

However, both (19) and (12) cannot both hold. Thus, in the presence of fixed costs, no Nash equilibrium exists in which some mineral rights owners contract with an exploration firm while others wait to contract with a development firm once a discovery is made.

So what is the Nash equilibrium? It cannot be that all mineral rights owners wait to contract with development firms, as development cannot occur without exploration. Thus the only possibility is that all mineral rights owners contract with the exploratory firm prior to exploration. Therefore, M=N. Hence the equilibrium number of development wells satisfies

$$\delta V'(w^*)=\gamma C_w, \tag{20}$$

which is the number of wells that maximizes field rents. Free entry in the exploratory market implies that the equilibrium mineral rents paid to landowners are

$$N\psi_x=\theta[\delta V(w^*)-\gamma C_w w^*]-\gamma C_x, \tag{21}$$

where $\delta V(w^*)-\gamma C_w w^*$ is the equilibrium field rents given w^* wells are drilled on a successful field.

In contrast to the standard common property view of oil fields, this contracting equilibrium is efficient. We obtain this counterintuitive result because of four related factors. First, the exploration firm is necessary in order to have production. This means that $M \geq 1$ is required of any equilibrium. Second, exploration firms face a fixed cost—the drilling of an exploratory well—which must, in expectation, somehow be recouped. Third, free entry by risk neutral firms into exploration and development means both types of firms earn normal (zero) expected profits. Fourth, mineral rights owners are free to contract with whomever they please. These last two assumptions fix the payments exploratory and development firms must make to landowners. It is not possible for the exploratory firm to recoup their fixed cost when some mineral rights owners' contract with other firms. Thus any equilibrium in which there is exploration and the fixed costs of exploration are recouped by the exploratory firm in expectation must have only one firm holding the development rights to a field.[19]

4.1. The effect of contractual failures

The contracting equilibrium we have described could fail if there is not free entry, or if some private information remains. Libecap and Wiggins (1985) and Yuan (2002) each provide examples in which more than one firm develops a field. Kellogg (2009, Table 1, p. 37) finds that during the period 1991–2005, over 25% of fields in Texas had only one producer, and at least half of the fields in his sample had two or fewer producers, with the mean being 2.8 producers per field. Similarly, Hendricks and Porter (1988), in their study of Gulf of Mexico offshore leasing, observe that it is rare to see two firms with adjacent properties compete in bidding on newly available adjacent tracts. This evidence suggests that the common property dissipation may have been small.

Firm level studies of exploration activity in the Gulf of Mexico (Hendricks et al., 1987; Hendricks and Kovenock, 1989; Hendricks and Porter, 1988) have found evidence of information asymmetries in offshore drilling. They observed that firms who held private information from adjacent lease-holdings obtained higher net *ex post* returns on their leases than firms lacking that information. Hendricks and Porter (1996) studied the behavior of firms subsequent to obtaining a lease. Firms which had private information from nearby leases tended to quickly drill exploratory wells on their leases, but firms lacking information about nearby leases tended wait to try to gain information from drilling on neighboring leases owned by other producers. Lin (2007, 2009) finds that firms' profits are increasing in the development activities of neighboring firms. In all of these papers information spillovers were observed, although the spillovers were much less perfect than we have assumed. But this evidence does not suggest what effect information asymmetries would have upon the levels of exploratory drilling relative to development drilling, nor does it inform us as to the evolution of exploratory and development drilling over time.

Nevertheless, it is useful to see the effect contractual failure may have. The number of development wells drilled in a symmetric Nash equilibrium with $n \leq N$ development firms satisfies (e.g., Yuan, 2002)

$$\left(1-\frac{1}{n}\right)\left[\frac{\delta V(w_n)}{w_n}-\gamma C_w w_n\right]+\frac{1}{n}[\delta V'(w_n)-\gamma C_w w_n]=0.$$

When $V(w)$ is concave, w_n is increasing in n. Thus, differentiating the total rents paid to landowners with respect to the number of development firms, n, yields

$$\frac{d(N\psi)}{dn}=\theta[\delta V'(w_n)-\gamma C_w]\frac{dw_n}{dn}<0.$$

Hence, the mineral rents paid to landowners is decreasing in n (i.e., $w_n > w^*$ implies that $\delta V'(w_n) < \gamma C_w$). Thus, the effect of contractual failure is to dampen the effect of scarcity rents on the time paths of exploratory and development drilling.

5. Testable hypotheses

Now let us derive how the numbers of exploratory, development, and total wells drilled vary over time, and how changes in the exogenous parameters of the model affect the relationship between exploratory and development drilling.

Let $A(t) \geq 0$ denote the area of potential hydrocarbon bearing land which has not yet been explored by time t. Then $A(t)$ is given by

$$A(t)=A(0)-\int_0^t Nx(s)\,ds, \tag{22}$$

where $A(0)$ is the total amount of land available to be searched, and N units are searched by each exploratory well drilled. Since θ is constant, all land is equally likely to contain a mineral deposit. Therefore, all land is eventually explored. Thus, there exists some time $\overline{T}$ when all land has been explored. At this point in time $A(\overline{T})=0$, so that the total amount of land that has been searched is $A(0)$.[20]

The system of equations (7), (20), and (21) implicitly describe $x(t)$, $w(t)$, and $D(t)$, the numbers of exploratory drilled, development wells drilled per new field, and total wells drilled, respectively, in terms of time and the parameters of the model. There are three forces at work that affect how $x(t)$, $w(t)$, and $D(t)$ change over time. The first of these is the Hotelling

[19] Other fixed costs would have a similar effect. Examples include the seismic cost associated with exploration, the installation of a transportation pipeline, or the installation of injection wells to maintain field pressure.

[20] If land is heterogeneous, then $A(\overline{T}) \geq 0$, $\psi(\overline{T}) \geq 0$, and $A(\overline{T})\psi(\overline{T})=0$ (Boyce, 2009). In either case, $x(\overline{T})=0$.

Table 2
The effect of a permanent and unexpected increase in parameter α at time t on the number of wells drilled at t, by type of well drilled.

Parameter (α)	Development wells drilled per new field, $w(t)$	Exploratory wells drilled, $x(t)$	Total wells drilled, $D(t)$
Gross value of reserves, $p\delta R_0$	+	+	+
Development success rate, ϕ	−	+	+
Exploration success rate, θ	−	+	+
Drilling cost, $\gamma c'(D)$	−	−	−

Notes: A '+' ('−') sign indicates that an unexpected permanent increase in parameter α has a positive (negative) effect upon the number of wells drilled at time t=0. These comparative statics results take into account endogenous changes in the mineral rights rental price, ψ, and the time it takes to exhaust searching the available land. See Appendix C for the derivations.

scarcity effect, which causes the rental price of mineral leases, $\psi(t)$, to rise at rate $\dot{\psi}(t)/\psi(t) = r$ in order to compensate landowners who wait to sell their leases. Second, technological change increases the reserves recoverable per field, $\delta(t)$, over time at rate $\dot{\delta}(t)/\delta(t) = g_\delta > 0$. Third, technological change lowers drilling costs, $\gamma(t)$, over time at rate $\dot{\gamma}(t)/\gamma(t) = -g_\gamma < 0$.

Time differentiating (20) and (21), using (7) to find an expression for the rate of change of total wells drilled, noting that (20) holds for all θx new fields, yields the following (see Appendix B):

$$\dot{x}(t) = \frac{[\delta V'' - \theta x \gamma c''](r-g_\delta)N\psi}{-(1+\theta w)\delta V''\gamma c''} + \frac{(g_\delta + g_\gamma)\gamma c'}{(1+\theta w)\gamma c''}, \tag{23}$$

$$\dot{w}(t) = \frac{(r-g_\delta)N\psi}{-\delta V''}, \tag{24}$$

$$\dot{D}(t) = \frac{-1}{\gamma c''}[(r-g_\delta)N\psi - (g_\delta + g_\gamma)(1+\theta w)\gamma c']. \tag{25}$$

As written, the denominator of each expression in (23)–(25) is positive in sign. Thus we may focus on the numerators to sign the time derivatives. As the expression in the numerator of (24) also appears in (23) and (25), we begin with it. There are two conditions that need to be satisfied in order for $\dot{w}$ to be positive in sign. First, the rental price ψ must be non-zero. This occurs only if the rents are not fully dissipated. Second, the equilibrium rate at which the mineral rights rental price appreciates, r, must be greater than the rate of growth in the recovery rate technology, g_δ.[21] In (23), the term in brackets in the numerator of the first expression is negative so long as the second-order-condition is satisfied for the choice of w. Thus, the first expression in (23) is negative under the same conditions that the right-hand-side of (24) is positive. The second expression in (23), however, is positive in sign given the sign conventions for g_δ and g_γ. Therefore, $\psi > 0$ and $r > g_\delta$ are jointly necessary, though not sufficient, to cause the number of exploratory wells drilled to decline over time. In (25), we see the same sort of dynamic forces as in (23). The term involving $(r-g_\delta)N\psi$ has a negative coefficient and the term involving $g_\delta + g_\gamma$ has a positive coefficient.

Thus, if $r < g_\delta$, the number of exploratory wells and the number of total wells are rising over time and the number of development wells per field is declining, all else constant. When ψ is zero, the number of exploratory wells and the number of total wells are rising over time and the number of development wells per field is constant, all else constant. Finally, only if ψ is sufficiently large and $r > g_\delta$ is the number of exploratory wells and the number of total wells falling over time and the number of development wells per field rising over time. Thus, if the Hotelling effects through the terms $(r-g_\delta)N\psi > 0$ dominate, the number of development wells drilled per field is increasing over time whereas the number of total wells drilled and the number of exploratory wells drilled are each decreasing over time. In contrast, if the technological change effects dominate, then the opposite signs occur for each of the drilling aggregates. Therefore, only if Hotelling effects are sufficiently large, do we observe their effects. If Hotelling effects are not sufficiently large, either because of rapid technological change or because contractual failure drives down the mineral rights rental value, then the opposite occurs. This provides an *asymmetric* test of the presence of scarcity effects.

The time derivatives in (23)–(25) are *ceteris paribus* dynamics of the three drilling aggregates. We now analyze how the numbers of different types of wells drilled are affected by permanent unexpected changes in observable parameters. The comparative dynamics exercises conduct the following experiment. Suppose at time t a *permanent* and *unexpected* increase occurs in parameter α of the model. Then what happens at time t to the number of development wells drilled per field, to the number of exploratory wells drilled, and to the total number of wells drilled? As changes in the parameters also affect the mineral rights scarcity price, the land constraint (22) is used to adjust the value of $\psi(t)$ to keep the total area of land explored constant. Thus after the parameter change, exploratory and development drilling follow a new path. If the number of exploratory wells drilled rises (falls) at time t=0, then the new path for exploratory drilling must decline at a more (less) rapid rate in order to satisfy the land constraint (22). In all equilibria, we impose the transversality condition that forces $x(T)$=0.[22] Table 2 summarizes the results of numerical simulations on comparative dynamics reported in more detail in Appendix C.

[21] Barro and Xavier Sala-i-Martin (2004, p. 112) estimate total factor productivity growth is around 2%, which may be a reasonable estimate for g_δ (see also Cuddington and Moss, 2001). If land is heterogeneous, this condition requires that $\dot{\psi}/\psi > g_\delta$.

[22] A complete description of the model is found in our working paper (Boyce and Nøstbakken, 2009). See also the extension by Boyce (2009).

All else constant, there is a higher level of drilling today if the gross returns to drilling, given by price times the reserve additions, pR_0, are higher and if the cost of drilling, $c'(D)$, is lower. An increase in the success rate of either exploratory or development drilling increases the number of exploratory wells drilled but decreases the number of development wells drilled per field. When the development success rate increases, fewer development wells have to be drilled per field to obtain the same level of field productivity. Since fewer development wells have to be drilled, the net return to discovering a field increases, thus the number of exploratory wells rises. An increase in the exploratory success rate raises the return to exploratory drilling, consequently exploratory drilling increases. This lowers the relative return from an additional development well, which causes firms to substitute to more exploratory drilling while fewer development wells are drilled per field.

6. Empirical analysis

Let us now turn to an empirical analysis of the hypotheses we have just derived regarding exploration and development drilling of oil and gas wells in the U.S., 1955–2002.

6.1. Econometric specification

There are a number of complications ignored in the development of the theoretical model that we need to control for in our empirical analysis. For example, we assumed for simplicity that firms were able to correctly forecast future prices and technologies. While real price growth was relatively flat during the 1960s, making this an easy task, it is unlikely that firms correctly forecast either of the two major oil price shocks of 1973–1974 and 1979–1980. We control for the effect of these unexpected shocks by including the current real prices of oil and natural gas. In addition, mature fields lose their pressure over time and may require additional wells to extract the oil and gas or to re-inject water or natural gas. We control for this by including several measures of field maturity, such as the ratio of current oil reserves to the sum of cumulative production and oil reserves, and we explicitly control for the number of new enhanced oil recovery projects. In addition, we control for the discoveries of coal bed methane gas fields, which require higher densities of development wells. There may also be shocks to the set of information about geologic conditions generally within a state. We control for the average size of discoveries, average drilling costs, and average depth of wells drilled in each state to capture these types of shocks. In addition, there are institutional differences and differences in the ownership patterns across states. Some, such as federal land percentages, vary over time and are directly observable. Others are relegated to fixed or random effects which differ across states.

The econometric model we estimate is a linear approximation of the model given by Eqs. (7), (20) and (21) to explain the variation in the number of development wells, exploratory wells, and total wells drilled.[23] The models we estimate are of the form:

$$y_{itk} = \beta_{0k} + \boldsymbol{\beta}_{1k}\mathbf{X}_{itk} + \boldsymbol{\beta}_{2k}\mathbf{Z}_{itk} + \beta_{3k}T + \varepsilon_{itk}, \tag{26}$$

where y_{itk} are the observed levels of drilling of type $k \in \{\text{development wells per field, exploratory wells, total wells}\}$ in state i in year t; T is the time trend; $\mathbf{X}_{itk}$ is a matrix of model parameters other than time; and $\mathbf{Z}_{itk}$ is a matrix of other control variables. The β_{jk} are coefficients to be estimated and ε_{itk} is the error term, where $\varepsilon_{ikt} = \alpha_{ik} + e_{ikt}$, with α_{ik} a state specific fixed or random effect and e_{ikt} a white nose residual. The numbers of exploratory and total wells drilled are the raw numbers of wells drilled as reported in the data sources. The exploratory wells drilled data are what the American Petroleum Institute calls "wildcat new field exploration."[24] The development wells per new field variable, w_{it}, is calculated from the observed total development wells drilled, W_{it}, as $w_{it} = W_{it}/\theta_{it}x_{it}$, where $\theta_{it}x_{it}$ is the number of fields discovered in state i in year t. The first matrix of explanatory variables, $\mathbf{X}_{itk}$, consists of variables from the theoretical model presented above. This includes the real prices of oil and gas, the probability of success at both the exploratory and the development levels, the real (average) cost of drilling a well, the reserve additions per field, and the real interest rate. The matrix $\mathbf{Z}_{itk}$ consists of additional control variables, including the percentage of drilling offshore, the percentage of federal land ownership, measures of field maturity, counts of the number of enhanced oil projects, the number of coal bed methane discoveries, the average depth of wells drilled, and the total number of producing wells in a state. Each explanatory variable varies across states and time, except for the crude oil and natural gas prices and the real interest rate, which only vary across time.

We first estimated a baseline model including only the $\mathbf{X}_{itk}$ variables. These models were used to select the proper estimation methodology. The Breusch–Pagan test of the null hypothesis that the variance of the state-specific error term of a random effects model is zero was rejected for all three dependent variables, rejecting a pooled ordinary least squares estimation of the model in favor of a panel estimator. A Hausman test was used to select between a fixed or random effects panel estimator. A fixed effects estimator was preferred for the number of development wells drilled per new field, but the

[23] The ideal approach would be to estimate the structural model or a true reduced form model. Unfortunately, it is not straight-forward to turn the non-linear system (7), (20) and (21) into a true reduced form model that allows us to identify all model parameters and relevant dynamic effects. Furthermore, data are not available at the field level, which means we cannot directly test the specification of the model.

[24] This excludes exploratory wells that seek to extend the boundaries of a known field. However, similar results were obtained when the number of exploratory wells also includes these types of wells.

random effects estimator was preferred for the number of exploratory wells drilled and total number of wells drilled. Finally, test statistics from Woolridge's (2002, p. 282) test of an autocorrelated error structure, and a likelihood ratio test of heteroscedasticity were performed. For all three dependent variables, the results indicated the presence of heteroscedasticity, and in several cases autocorrelation was also detected. To control for these effects, we allowed for heteroscedasticity and first-order autocorrelation in the error terms in the cases where the latter was found to be a problem.[25] The modified empirical model was estimated by the feasible generalized least squares (FGLS) method.

6.2. Empirical results

FGLS estimation results for the panel of 32 states over the period 1955–2002 of the number of exploratory and total wells drilled and the number of development wells drilled per new field are presented in Table 3. Five specifications of the FGLS models are estimated for each drilling variable. Model 1 contains the year time-trend, real oil and natural gas prices, real drilling costs, and exploration and development success probabilities. Model 2 adds offshore percentage and the size of oil reserve additions per new field as further cost and rent shifters. Model 3 adds natural gas reserve additions per new field, federal land percentages (which varied over time in every state), and the real interest rate as further cost and rent shifters. Model 4 adds the ratio of current reserves to cumulative discoveries, $R_t/(R_t+\sum_{s=0}^{t} Q_s)$, for both oil and gas to control for the average maturity of the extraction activity in the state (Libecap and Wiggins, 1985), the number of enhanced oil recovery projects begun in a state, and the number of new coal bed methane fields discovered in each year to control for effects of infill drilling and higher densities required for coal bed methane gas fields. Finally, model 5 adds the average depth of wells drilled in the state and the total number of wells operating in the state to control for possible reserve heterogeneity and for possible learning effects, respectively (Norgaard and Leu, 1986).

The econometric results are displayed in Table 3. The main theoretical prediction is that if Hotelling effects dominate, we expect that the number of exploratory wells drilled and the total number of wells drilled to decline over time, and the number of development wells per new field to rise over time. Between 0.5 and 3.5 fewer exploratory wells were drilled in each state from year to year, and between 7 and 14 fewer total wells were drilled each year on average, all else constant. By way of comparison, from Table 1, 172 (=5514/32) exploratory wells and 1314 (=42 033/32) total wells were drilled on average in each state in each year. Each of these results is statistically different from zero at the 1% confidence level. The number of development wells drilled on each new field increased by between 0 and 1.5 wells per year on average. From Table 1, each state drilled 115 new development wells per new field per year. We conclude that the oil and gas contracting equilibrium has preserved a large enough share of the economic rents to overcome the offsetting effects of technological change.

The number of exploratory, development wells, and total wells drilled is predicted to be increasing in output prices and decreasing in costs of drilling. A one dollar increase in the real price of gas is associated with an increase of between 4 to 12 additional development wells drilled, and between 50 and 60 additional wells drilled in total. An increase in the real crude oil price has a significant and positive effect on exploratory drilling and the total number of wells drilled. However, the point estimates for the real oil price effect on the number of development wells per field are negative.[26] An increase in real drilling costs per well of $1000 results in between 4 and 15 fewer development wells drilled per field, and between 10 and 100 fewer total wells drilled. The effect of an increase in drilling costs is significant at the 5% confidence level only in model 2.

An increase in the probability of success in drilling of either exploratory or development wells is predicted to increase the number of exploratory and total wells drilled and decrease the number of development wells drilled per field. These results are somewhat mixed. Only the effect of the exploratory success rate on development drilling is persistently significant (1% level) across all estimated model specifications and it switches signs in two specifications.

The model predicts that states in which the crude oil and natural gas reserve additions per exploratory well drilled are higher will tend to drill more wells per field and more wells in total, all else constant. The estimated coefficients for these variables are only significantly different from zero for development wells drilled per field, and there the effect of gas reserve additions per well has the expected sign, but oil reserve additions have a negative impact on development drilling.

As the federal government may control common property problems better than private mineral rights owners (Libecap and Wiggins, 1985), the federal land percentage is included in models 3–5. This is an imperfect measure, as it fails to include offshore percentages and because statewide federal land percentages may not correspond to federal percentages of oil and gas producing lands. We find that states with larger proportions of federal land tend to drill fewer exploratory and total wells, and perhaps, fewer development wells per new field. The latter finding is consistent with Libecap and Wiggins's (1985) results, however, it occurs in only one of the three specifications in which federal land appears as a regressor. The weakness of this result suggests that federal land ownership may have had little impact on how fields are developed, which (indirectly) supports the hypothesis that the contracting equilibrium is efficient even on non-federal lands. The effect on exploratory and total drilling could be due to higher regulatory costs on federal lands.

An increase in the ratio of proved reserves to cumulative discoveries has a positive effect on the number of development wells drilled per field. Thus states in an earlier stage of development tend to place more wells on a field. This could be because larger fields

[25] The error term of equation k then becomes $\varepsilon_{itk}=\rho_k\varepsilon_{it-1k}+e_{itk}$, with $\rho_k \subset (-1,1)$, where e_{itk} is an independent, identically distributed noise term. The parameter ρ_k was assumed to be the same for all states for each model k.

[26] This is apparently due to multicollinearity between natural gas and crude oil prices (r=0.77). Dropping the natural gas price from the estimating equations causes the crude oil price to be positive in all models, and statistically significant in most models.

Table 3
Feasible generalized least squares model estimates.

Model	(a) Exploratory wells drilled					(b) Total wells drilled					(c) Development wells drilled per new field				
	(1)	(2)	(3)	(4)	(5)	(1)	(2)	(3)	(4)	(5)	(1)	(2)	(3)	(4)	(5)
Year	***−0.44	***−0.75	***−2.10	***−3.58	***−1.35	0.02	***−7.53	***−8.59	***−11.79	***−14.26	**0.53	0.16	**0.35	***1.35	***1.48
	(0.15)	(0.20)	(0.26)	(0.36)	(0.30)	(0.29)	(1.85)	(2.21)	(2.20)	(2.37)	(0.24)	(0.25)	(0.15)	(0.29)	(0.29)
Exploration success (%)	0.04	−1.49	2.27	−0.41	***0.65	−3.33	44.1	64.31	50.76	***8.97	***−116.7	***−155.2	***−113.3	***−158.4	−0.32
	(1.81)	(3.92)	(4.81)	(5.09)	(0.23)	(8.70)	(40.20)	(40.38)	(41.14)	(1.50)	(9.37)	(12.97)	(12.13)	(12.77)	(0.22)
Development success (%)	−0.72	1.71	2.04	2.57	1.19	*−4.12	−50.06	*−68.48	−46.74	***55.48	***−12.75	*−10.33	***52.30	*−9.65	***9.70
	(1.50)	(3.88)	(6.20)	(6.64)	(2.79)	(2.45)	(34.14)	(37.40)	(36.06)	(19.11)	(4.46)	(5.87)	(6.47)	(5.68)	(2.71)
Real oil price ($/bbl.)	***0.26	0.24	***0.66	***0.86	−0.09	***1.01	***8.87	***8.07	***7.14	−13.28	−0.09	−0.22	−0.18	*−0.38	***−13.25
	(0.10)	(0.17)	(0.22)	(0.25)	(1.31)	(0.24)	(1.27)	(1.44)	(1.45)	(11.65)	(0.18)	(0.20)	(0.22)	(0.21)	(4.10)
Real gas price (cents/tcft)	0.23	0.61	1.06	1.14	−2.83	−1.83	***52.79	***60.36	***53.55	32.26	***8.13	***8.84	*4.78	***12.22	***−164.08
	(1.30)	(2.31)	(2.73)	(3.15)	(4.32)	(2.94)	(17.62)	(18.89)	(18.64)	(41.69)	(2.31)	(2.74)	(2.45)	(2.72)	(13.31)
Real drilling cost per well ($1000s)	*1.51	**−1.90	0.91	1.21	−10.6	**8.19	***−59.19	*−20.46	−14.46	**−106.0	−4.01	***−13.31	***−14.46	***−10.71	**−13.11
	(0.82)	(0.83)	(1.33)	(1.62)	(6.80)	(3.85)	(8.55)	(10.45)	(10.37)	(42.04)	(2.77)	(2.52)	(1.89)	(3.59)	(5.79)
Offshore (%)		0.22	0.31	**0.43	0.31**		2.71	1.51	1.64	1.19		***1.64	***1.39	***1.24	1.06***
		(0.17)	(0.20)	(0.21)	(0.15)		(1.94)	(1.47)	(1.45)	(1.44)		(0.27)	(0.26)	(0.41)	(0.41)
Oil reserves per new field		−11.93	−10.38	2.32	−1.57		−74.84	−31.77	−104.56	44.33		137.65	**−759.4	***−475.1	*−313.6
		(11.88)	(16.48)	(18.50)	(13.82)		(136.80)	(129.10)	(129.50)	(128.70)		(87.63)	(297.00)	(179.00)	(168.82)
Gas reserves per new field			−0.89	−11.16	0.62			−4.87	−6.27	−56.97			***1409	***637.5	***584.4
			(9.94)	(10.17)	(7.74)			(72.77)	(74.11)	(72.81)			(95.90)	(80.49)	(81.02)
Federal land (%)			***−1.22	***−0.96	**−0.39			***−4.50	***−3.47	−0.25			***−0.18	0.07	0.05
			(0.13)	(0.19)	(0.19)			(0.92)	(1.05)	(1.07)			(0.06)	(0.12)	(0.11)
Real interest rate (%)			−0.28	−0.38	−0.54			*7.45	5.05	**8.36			−0.55	−0.29	−0.55
			(0.62)	(0.70)	(0.65)			(3.95)	(3.92)	(4.09)			(0.55)	(0.51)	(0.51)
Oil reserves/(oil reserves + cumulative production)				−27.6	−7.61				*−216.54	−141.25				27.14	**42.62
				(21.57)	(17.71)				(115.90)	(120.10)				(19.85)	(20.44)
gas reserves/(gas reserves + cumulative production)				**−55.82	−5.28				−46.24	−53.94				*26.40	***38.71
				(23.55)	(23.44)				(132.68)	(131.20)				(13.87)	(14.45)
Enhanced oil recovery projects				*1.59	*1.32				**17.60	*13.04				0.15	−0.02
				(0.82)	(0.75)				(8.91)	(7.77)				(0.27)	(0.29)
New coal bed methane fields				1.16	1.99				14	4.62				0.58	1.02
				(1.66)	(1.52)				(12.38)	(11.60)				(1.68)	(1.84)
Average depth (1000 ft)					−0.64					1.63					0.33
					(0.45)					(3.30)					(0.73)
Producing wells(1000 s)					*−0.31					***29.80					***0.44
					(0.18)					(2.05)					(0.08)
Observations	1327	1097	883	883	860	1327	1097	883	883	860	1225	1069	864	864	850
States	32	25	25	25	24	32	25	25	25	24	32	25	25	25	24
Estimation method	RE	RE	RE	RE	RE	RE	RE	RE	RE	RE	RE	FE	FE	FE	FE
Autocorrelation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No
Log-likelihood	−6773	−5821	−4590	−4600	−4512	−8963	−7765	−6243	−6313	−6072	−6594	−5827	−4856	−4666	−4666

Notes: Standard errors in parentheses. Significance levels: $^{*}p < 0.10$, $^{**}p < 0.05$, $^{***}p < 0.01$. "FE" is fixed effects; "RE" is random effects. All models correct for heteroskedasticity. Only those models for in which the "Autocorrelation" row indicates "Yes" correct for autocorrelation. Seven states drop out of models 2–5 because they have no crude oil or natural gas reserves data (see Table 1). In addition, Florida drops out of model 5 for lack of data on the number of producing gas wells.

are typically discovered first.[27] The negative effect on exploratory wells drilled could be because, as observed by Hendricks and Porter (1988), firms prefer to wait and freeride on the information of others in areas where there is little prior knowledge about the geology.

Model 4 controls for possible confounding effects in development drilling due to enhanced oil recovery and due to coal bed methane fields. The coal bed methane variable had no effect. However, states in which there are larger numbers of enhanced oil recovery projects tend to do more drilling in total, and perhaps more exploratory drilling. Finally, in model 5, we added the average depth of wells drilled and the total number of producing wells in the state. The average depth of wells is not statistically different from zero in any specification. The total number of producing wells in a state serves as proxy for possible learning by doing effects. In this case, one would expect this would increase drilling. We find a positive effect on the number of development wells drilled per new field and on total wells drilled, but the effect is negative on the number of exploratory wells drilled.

7. Discussion and conclusions

This paper derives and empirically tests an economic model of exploration and development for crude oil and natural gas fields. We argue that exploration is characterized as a fixed cost. In order for exploration firms to recoup these fixed costs, the competitive equilibrium requires that they contract with all potential mineral rights owners in advance of exploration. Thus, we argue that crude oil and natural gas development in the U.S. has been efficient.

The level of detail from the state-wide data we analyze does not allow us to empirically specify and test a strong hypothesis of efficiency. However, we derive a set of comparative dynamics results, and these are tested empirically. In particular, we predict that if contracting has been efficient, then all else equal, Hotelling scarcity effects cause firms to substitute over time from exploratory drilling into development drilling. This occurs because mineral rights costs are paid at the moment of exploration and are thus sunk at the time of development. This prediction, along with several other dynamic properties of the model, was tested using a panel of states over the period 1955–2002.

We find that significant Hotelling scarcity effects are consistent with the essential features of the data. In particular, all else equal, the number of exploratory wells drilled has been declining over time while the number of development wells drilled per field has been rising over time. This cannot happen when the industry is characterized by low scarcity rental prices, either due to poorly defined property rights or to declining Ricardian field quality, nor to an industry in which technological changes have dominated scarcity effects. In addition, the other comparative dynamics predictions from the model are broadly supported by the data. Furthermore, we reject the alternative hypothesis that the higher density of development drilling is simply due to effects of using enhanced oil recovery methods or of targeting harder to extract gas from coal bed methane fields. While we cannot say what proportion of rents have been preserved, our results suggest that the rents have been sufficiently large to overcome the offsetting effects that technological change has had upon the pattern of drilling. This casts doubt on the hypothesis that large scale rent dissipation has taken place in the U.S. oil and gas industry.

On the basis of our aggregate data, we cannot tell whether our findings are due to contractual efficiencies or to some other cause. It is possible that this is simply evidence that regulatory responses to the common pool problems have been effective. States have imposed regulations on well-spacing minimum distances, quotas on production, and mandatory unitization requirements. These have likely been in response to contractual failures. However, absent being able to tie a panel of regulatory changes to our drilling data, this is merely speculation.

We conclude with a conjecture as to why our results differ from those previously presented in the literature. The U.S. oil industry found the larger more valuable fields first.[28] Much of the previous research on crude oil field development uses data from the pre-World War II era, which was characterized by discoveries of larger fields.[29] When a field is larger than expected, the exploration firm faces rivals at the development stage. This could explain why, during the period 1955–2002, new reserve discoveries increased by nearly 150% relative to 1859–1954 discoveries, while new wells drilled increased by only 125%.

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Appendix A. Data sources and construction

All drilling data (number of wells drilled by type and outcome) prior to 1967 are from *World Oil* (the August "Annual Review Issue"), and drilling data from 1967 forward are from *Quarterly Well Completion Report*, published by the American

[27] The mean year of discovery of the 325 U.S. fields over 100 million barrels in size is 1938 (source: *Oil & Gas Journal*, "U.S. fields with ultimate oil recovery exceeding 100 million bbl.", January 26, 1998, pp. 82–84), while the mean year of discovery of all fields known by 2005 is 1965 (source: the Energy Information Agency's "Oil and Gas Field Code Master List 2007").

[28] See no. 29.

[29] Yuan (2002), for example, cites data from 1938–40. Libecap and Wiggins (1984), Libecap and Wiggins (1985), and Wiggins and Libecap (1985) focus on fields in Oklahoma and Texas during the period 1926–35.

Petroleum Institute (API). The total drilling and exploratory drilling data are the raw numbers of wells completed. Exploratory drilling is "new field wildcat" drilling, which the American Petroleum Institute defines as drilling at a distance of more than one mile from a known field.

Price, production, and reserves data 1955–2002 are from the API *Basic Petroleum Data Book*, and cost of drilling data are from the API *Joint Association Survey on Drilling Costs*.[30] Production data prior to 1954 is from the "Petroleum Facts and Figures" (Centennial Edition, 1959), American Petroleum Institute.

The offshore percentage of exploratory wells is the reported number of offshore exploratory wells divided by the total exploratory wells drilled. These data are only available for Alaska, California, Louisiana, and Texas. Exploration and development success rates are measured as the proportion of exploratory or development wells drilled that find oil or gas. The number of new fields is calculated from "Crude oil and Natural gas Field Master List 2005," U.S. Department of Energy, Energy Information Agency, DOE/EIA-0370(05)). Reserve additions, RA_{it}, are measured as $RA_{it}=R_{it+1}-R_{it}+Q_{it}$, where R_{it} and Q_{it} are reserves and production, respectively, in state i in period t. This number is divided by the total number of exploratory wells drilled to get reserve additions per exploratory well drilled. The ratio of reserves to the sum of reserves plus cumulative production is calculated by the authors.[31]

The coal bed methane data source is the "Crude oil and Natural gas Field Master List 2005," U.S. Department of Energy, Energy Information Agency, DOE/EIA-0370(05)).[32] The enhanced oil recovery data is from the *Oil & Gas Journal Survey of EOR Projects* (1986–2004). The data exclude EOR projects begun before 1986 that were no longer in operation by 1986.[33] The federal land percentage is from the *Statistical Abstract of the United States*, various years.

Appendix B. Derivation of drilling dynamics

The time differentials of (20) and (21), using (22) to obtain an expression for $\dot{D}$, are

$$\dot{x}(t)=\frac{-\{rN\psi-g_\delta\delta[\theta V-(1+\theta w)V']\}(\theta x)^2\gamma c''}{-\theta x(1+\theta w)^2\gamma c''\delta V''}+\frac{\theta x\delta V''\{rN\psi-\theta g_\delta\delta V-(1+\theta w)g_\gamma\gamma c'\}}{-\theta x(1+\theta w)^2\gamma c''\delta V''} \tag{B.1}$$

$$\dot{w}(t)=\frac{\{rN\psi-g_\delta\delta[\theta V-(1+\theta w)V']\}\theta x(1+\theta w)\gamma c''}{-\theta x(1+\theta w)^2\gamma c''\delta V''} \tag{B.2}$$

$$\dot{D}(t)=\frac{\theta x(1+\theta w)\delta V''\{rN\psi-\theta g_\delta\delta V-(1+\theta w)g_\gamma\gamma c'\}}{-\theta x(1+\theta w)^2\gamma c''\delta V''} \tag{B.3}$$

Substituting for $\theta\delta V(w)$ from (20) and using (21) to note that $\delta V'(w)=\gamma c'(D)$ yields the expressions in the text.

Appendix C. Effects of changes in parameters on number of wells drilled

We derive the comparative dynamics results using numerical methods. In each case, we set $g_\delta=g_\gamma=0$ and hold $\delta=1$. Given that $V(w)=p\phi R_0 w/r-g+\phi w$ from (6), and letting $c(D)=\gamma D^2$, we may solve (20), (21) and (7) for $w(t)$, $x(t)$ and $D(t)$:

$$w(t)=\frac{b_t+c_t\sqrt{a_t+b_t}}{a_t},\quad x(t)=\frac{a_t^3}{\gamma\phi(c_t+\sqrt{a_t+b_t})^3\sqrt{a_t+b_t}}$$

and

$$\text{and } D(t)=\frac{a_t^2}{\gamma\phi(c_t+\sqrt{a_t+b_t})^2}, \tag{C.1}$$

where

$$a_t=\phi(\theta p_0e^{gt}R_0-\psi_0e^{rt}),\quad b_t=(r-g)\theta\psi_0e^{rt},\quad \text{and } c_t=\sqrt{\theta^2p_0e^{gt}R_0(r-g)}. \tag{C.2}$$

We have written $\psi(t)=\psi_0e^{rt}$ in (C.2). As $t\to T$, both $x(t)$ and $D(t)$ approach zero, and $w(t)$ grows without bound. We use (C.1), (C.2), and the land constraint (22), to provide numerical comparative dynamics results. In each case, the base parameters are g=0, r=0.1, p_0R_0=40, $\phi=0.7$, $\theta=0.1$, and $\gamma=1$. Fig. 6 shows the simulation results. The base paths are given by solid lines, and the comparison paths are given by dashed lines. Setting $\psi_0=1$ yields values of T=12 and $A(0)$=15.4 for the base case.

[30] In the regressions, price and cost data are measured in real 2000 U.S. dollars, deflated using the Producer Price Index. In the figures, these data are in 2008 dollars.

[31] This takes a value of one for a state with no past production and approaches zero as total potential reserves are exhausted. The sample mean for oil is 0.18 and it ranges from 0.007 (Pennsylvania, 2001) to 0.96 (Alaska, 1970). For natural gas, the sample mean is 0.37 and it ranges from 0.032 (Louisiana, 2002) to 0.998 (Alaska, 1961).

[32] The U.S. average is 0.12 coal bed methane fields discovered per year. Colorado (0.74), Alabama (0.68), and Oklahoma (0.68) were the states with highest numbers of coal bed methane fields.

[33] The leading states for EOR projects were California (5.12 EOR projects per year), Texas (4.35), and Wyoming (1.83). The sample average was 0.49 EOR projects per year per state.

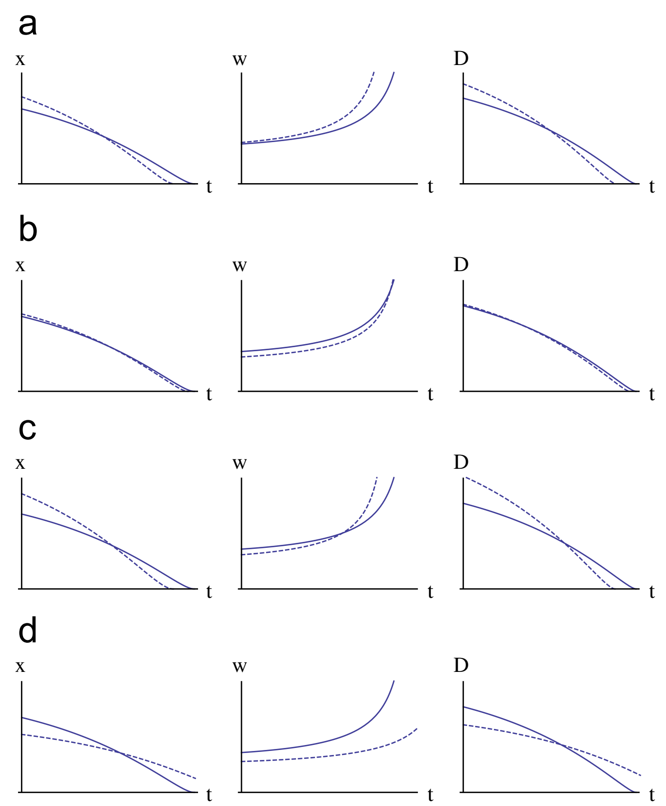

Fig. 6. Comparative dynamics: (a) effect of an increase in the value of reserves, $p\delta R_0$; (b) effect of an increase in the development success rate, ϕ; (c) effect of an increase in the exploration success rate, θ; (d) effect of an increase in the marginal cost, $\gamma c'(D)$.

The dashed curves are found by solving for the new value of such that $A(0)$, the area under the $x(t)$ curve, remains constant, after changing the parameter of interest. In panel (a), p_0R_0 increases to 50. In panel (b), ϕ increases to 0.95. In panel (c), θ increases to 0.2. In panel (d), γ increases to 2.

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