Three Essays in the Public Economics of Offshore Hydrocarbon Investment and Production

by

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For Kelly and Lars

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CHAPTER I

Introduction

Oil and natural gas account for approximately 60% of the energy produced worldwide. An already large and growing share of this total is due to oil and natural gas from offshore wells, particularly those in so-called "deep water" (at least several hundred meters deep). This implies that national governments, as both resource owner and taxing authority, currently have and will continue to play an outsize role in the development of this new energy source. First, to the extent that they permit outside (of the public sector) involvement to develop these resources at all, governments design the agreements to transfer mineral rights to private sector entities, while still retaining ultimate ownership. Second, these resources constitute an attractive source of government revenue: because the hydrocarbon source is immobile, taxable rents cannot flee the jurisdiction in which they are generated.

A thorough understanding of how hydrocarbon-producing firms respond to the government's policy choices is essential in order to evaluate the overall economic efficiency of these choices. In this dissertation, I use microdata collected by the U.S. federal government on oil and natural gas leasing in the U.S. Gulf of Mexico to measure how firms and markets behave in this policy environment.

In Chapter 1, I estimate the investment responses of hydrocarbon producers to a policy called the Deep Water Royalty Relief Act (DWRRA) which suspends the royalty, a type of production tax levied on oil and natural gas extracted from federal lands. I find that the potential for a royalty payments waiver: (1) increases the probability that an individual tract is acquired by an average of 193% (a mean increase of 5.6 percentage points); (2) decreases the probability that a lease is ever drilled during its observed lease term by an average of 14.5% (a mean decrease of 1.3 percentage points); and (3) increases the expected number of explored leases by 150%. The introduction of DWRRA also increases the average winning bid per lease by 60%. These estimates quantify the magnitudes of the discouraging effects of production taxation on oil and natural gas investment.

In Chapter 2, I quantify the implied value of information spillovers in oil and natural gas exploration using an event study design. Examining cumulative unpredicted daily stock returns for firms owning leases adjacent to a lease where a hydrocarbon discovery occurs during the trading days immediately preceding and following that discovery, I interpret the accumulated returns as the value of new information. I find that 25 trading days after a discovery, firms that own leases adjacent to the discovery lease (but not the discovery lease, itself) realize an average abnormal return that translates to $315 million in market capitalization. This effect is quantitatively large compared to average costs for drilling an exploratory well.

In Chapter 3, I measure how oil price affects water injection, a method for prolonging the productive lifetime of oil fields. I find that a $1 rise in price increases the water injected into the well's reservoir by approximately 650 to 950 barrels, equalling 7.5 to 9.5% of the mean monthly injection volume (depending on the sample chosen). Equating the estimated price effect with a potential tax effect, this finding has implications for how the government levies a royalty on mature oil fields for which operators invest in pressure maintenance.

CHAPTER II

Production Taxation and Offshore Oil Investment: Evidence from the Gulf of Mexico

2.1 Introduction

The U.S. government has authority over all submerged lands between three and 200 miles from its shores, including the estimated 101 billion barrels of oil and 480 trillion cubic feet of natural gas contained within this area, known as the Outer Continental Shelf, or OCS (Minerals Management Service (2006)).[1] The potential extraction of these resources represents substantial rents to the U.S. government: in fiscal year 2009, for example, the 367 million barrels of oil and 3.35 trillion cubic feet of natural gas produced in the U.S. Gulf of Mexico generated approximately $3.72 billion in royalty payments.[2] The federal government contracts with private industry for the development and extraction of these offshore resources – a multi-year process spanning several stages of investment – by leasing individual tracts to producing firms. Within these arrangements, the U.S. requires the payment of a royalty (a fixed-percentage tax levied on the price of each produced unit of oil or

[1] These estimates refer to "technically recoverable but undiscovered resources," i.e. those that would be producible if not necessarily economically viable with current technology. For perspective, the U.S. consumed roughly 6.4 billion barrels of oil and 23 trillion cubic feet of natural gas in 2008 (U.S. Energy Information Administration (2010)); from Table 1.3 and author's calculations.

[2] Source: Office of Natural Resources Revenue website, http://www.onrr.gov.

natural gas), however, the government enacted the Deep Water Royalty Relief Act (DWRRA) during the mid-1990s which waived royalty payments for Gulf of Mexico leases in greater than 200m of water for a limited time. In this paper, I use lease-level microdata from the U.S. Gulf of Mexico to determine how the royalty suspension induced by DWRRA changed firms' investment behavior prior to the production of oil and natural gas.

In my preferred estimates, I find that eligibility for the removal of royalty liability increases the predicted conditional probability of a tract being purchased by an average of 5.6 percentage points, which in percentage terms is 193%. DWRRA status also decreases the number of leases that are ever drilled during their lease terms (as measured by the cumulative distribution function for the first instance of a lease having an exploratory well, $F(\cdot)$). The CDF evaluated at T, the last period during which the lease is observed (see Appendix B for a more complete description of T) is lowered by 14.5% on average (or, 1.3 percentage points) by the presence of the royalty. Finally, I combine these point estimates within an estimator for the change in the expected number of explored leases due to the potential royalty waiver; I find an increase in the expected number of explored leases of 150%.[3]

The estimates reported above suggest that firms respond to a policy that lowers their taxes owed on production by both buying more leases and drilling more leases. The signs of these effects are sensible, as lower royalty liability *ceteris paribus* increases the value of the producing lease and therefore the value of the option to explore. The purpose of this paper, however, is to estimate the magnitudes of these effects. In order to estimate the sizes of these effects, I first construct detailed histories of leased and unleased spells for each deep water tract sold or available at any point during 1984-2000 in the Gulf of Mexico, using U.S. Department of Interior data. With these data, I control for observable measures of lease quality and then exploit both within-variation

[3]Very few leases ever reach the production phase, so I am unable to make any inferences about how the suspension of the royalty rate affects ultimate production.

(treatment depends on a price threshold) and between-variation (treatment depends on lease vintage) induced by DWRRA to estimate its effects within an empirical model of sequential investment.

A simple comparison of the relative magnitudes (and signs) of the reported effects does much to characterize the firms' behavioral responses to the royalty change. The combination of a large positive estimated value for the semi-elasticity for acquisition with respect to the policy and an analogous semi-elasticity for the CDF for the time of first exploratory drilling that is negative and smaller in magnitude implies that acquisition is more sensitive to the royalty than is exploration. Given that leases are sampled from a finite stock of tracts, and assuming minimally informed priors, tracts for which purchase is induced by the royalty treatment will be of lower quality, on average, than leases for which acquisition is inframarginal to the policy. Therefore, the inflow of leases that compose the acquisition response must necessarily be of lower mean quality and thus less likely to receive further investment in the form of exploratory drilling. Potential leaseholders reacted to the possible suspension of royalty payments by speculatively investing in such marginal leases, though the conditions that could have caused firms to exercise (more of) these options failed to materialize. While the policy's affect on exploration *conditional on acquisition* is unambiguously negative, the estimated effect on the raw number of leases drilled is positive, as predicted by theory.

This research has a number of policy-relevant implications. First, knowledge of firms' behavioral responses to a royalty waiver both informs the evaluation of DWRRA and also provides guidance to policymakers in crafting potential future tax incentive policies targeted at extractive industries. Regarding the latter, the estimated treatment effects suggest that royalty incentives can be an effective means for encouraging investment subsequent to acquisition.[4] This research also sheds light on a norma-

[4]Short of performing a simulation, it is not possible to characterize the effect of the royalty suspension on overall government revenue as these data are severely right censored from the standpoint

tively undesirable effect of the policy: increased lease holdings unaccompanied by a commensurate increase in drilling. With the record oil prices that occurred during the summer of 2008, some members of Congress asserted that leaseholders should engage in more drilling and waved the threat of a firm-specific moratorium for future leases or fines if new exploration did not materialize. While drilling capital constraints make the industry-wide level of investment advocated by members of Congress impossible (at least in the short run), the "inflated" lease holdings seem a response to the will of an earlier Congress to encourage more investment.

This research also contributes to our understanding of optimal leasing policy. Leland (1978) develops a theory for the optimal risk-sharing between the government and private firms for OCS oil and natural gas production. He concludes that the imposition of the royalty, although simple to understand and administer, is inconsistent with the efficient outcome because it induces too little investment, and that a higher royalty rate exacerbates this departure from optimality. Thus, movement away from the royalty towards other modes of rent capture might accordingly be welfare-improving. An obvious candidate is the winning bid, which theory predicts will capitalize (at least some of) the lost government revenue from a lower royalty. Wilson (1977) theorizes that as the number of bidders at auction increases (and thus the market better approximates a perfectly competitive one), the winning bid will fully capitalize any changes in expected tax payments. Although this paper does not constitute a test of the relative efficiency of winning bids vs. royalties, the large increase in the bid amount in response to the temporary lifting of royalty liability indicates capitalization occurs. Therefore an emphasis on the bid for the purpose of rent capture need not lower overall revenue greatly.

Additionally, this paper addresses two separate literatures: OCS hydrocarbon leasing and investment, and the taxation of oil and natural gas production. The

of production (a lease can produce for decades) and the estimated effect on bidding provides only a partial picture.

former literature is focused almost exclusively on strategic interaction – to an extent that the primary interest is not in OCS oil and gas leasing *per se* but rather in OCS oil and gas leasing as a useful environment in which to test theoretical models of strategic interaction, particularly in the context of incomplete and asymmetric information. Porter (1995) summarizes much of this literature and attributes the appeal of OCS leasing and production data to its detail and the fact that it is generated in a easily understood strategic environment. Using OCS auction data for 1954-1969, Hendricks et al. (1987) finds that the data are consistent with an auctions model in which one bidder is better informed than the others. Hendricks and Porter (1988) examines OCS "drainage" lease auctions during the period 1959-1969 and Hendricks et al. (1989) extends the sample period to 1959-1979.[5] Testing the hypothesis that the owners of the producing leases possess more information about the offered neighboring tracts than the competing bidders, the authors find observed bidding behavior to be consistent with a model of asymmetrically informed bidders. Hendricks et al. (2003) extends the analysis of first-price sealed bid auctions to "wildcat" lease auctions held during 1954-1970[6] – an environment characterized by symmetric information between bidders – to find that observed bidding is consistent with a symmetric common values model. Finally, Hendricks and Porter (1996) analyzes exploratory drilling on wildcat lease during the period 1954-1980, finding that a noncooperative model of drilling is appropriate for these data. None of this research, however, addresses taxation and its effects on firm behavior.

Turning next to the literature on the taxation of oil and natural gas production: empirical estimation of the effect of production taxation is complicated by the fact that the rate has not varied over time. This has necessitated the use of simulations in order to understand how different types of taxes affect efficiency and equity –

[5]Prior to the current area-wide leasing regime (see section 2.2.1), the government periodically conducted drainage auctions in which tracts adjacent to a producing lease were offered for bid.

[6]A wildcat lease is tract in an area where no previous drilling has occurred and thus no potential participant holds an informational advantage.

a leading example is Gamponia and Mendelsohn (1985). A recent empirical study in this area is Rao (2009). Using data for onshore oil wells during 1977-2008, she exploits variation in the federal Windfall Profit Tax to estimate an after-tax price elasticity of production of roughly 0.23. In contrast to Rao (2009), which estimates the effect of taxes on *existing* wells only, this paper estimates the effect of taxes on the investment decisions that necessarily precede production.[7] In estimating on the effect of (production) taxes on pre-production investment decisions, this paper fills a gap in the literature.

The rest of the paper proceeds as follows: section 2 provides background on federal offshore oil and natural gas leasing in general and DWRRA in particular. Section 3 outlines a theoretical model that generates predictions for behavioral changes owing to a change in the royalty rate. Section 4 describes the empirical implementation of the theoretical model and the data used for estimation. Section 5 presents and discusses the results while section 6 concludes.

2.2 Institutional Background

2.2.1 U.S. Federal Offshore Oil and Gas Leasing

The Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) within the U.S. Department of Interior leases subsea tracts on the OCS to individual private firms or consortia of private firms.[8] These tracts (called "blocks" when unleased and "leases" when leased) are underwater parcels of land that usually measure three miles by three miles, covering an area of nine square-miles or 5,760 acres. For administrative purposes, BOEMRE divides the Gulf of Mexico under U.S. ju-

[7]One exception is Ashton et al. (2005), a study commissioned by the Mineral Management Service to examine the effects of changes in royalty policy. The authors do not provide a model to underpin their empirical results, which are generated from specifications that are quite different from those given in this paper.

[8]BOEMRE is the agency that succeeded the Mineral Management Service (MMS), which ceased to exist with the issue of Interior Secretary Ken Salazar's Order 3299 on May 19, 2010.

risdiction into three so-called planning areas: the Western Gulf of Mexico (WGM), the Central Gulf of Mexico (CGM), and the Eastern Gulf of Mexico (EGM). Each planning area is then subdivided into so-called areas (the purpose of which seems to be block identification only) with each area completely gridded into individual numbered blocks (see Figure 2.1 for maps of the Central and Western Gulf of Mexico planning areas divided into both areas and blocks). Finally, one additional system of block categorization requires mention. BOEMRE divides blocks into water depth categories: 0-199m, 200-399m, 400-799m, 800-1599m, etc. These distinctions matter inasmuch as BOEMRE slightly varies lease contract terms by depth category. The most substantial difference is between the 0-199m group, which BOEMRE administratively considers "shallow" water, and all other depth groups, which are considered "deep" water.[9]

Individual blocks are leased in individual first-price sealed bid auctions. Generally speaking, a single "lease offering," which constitutes thousands of simultaneous first-price sealed bid auctions, is held one time per calendar year per planning area for all blocks in the planning area that are not leased at the time of the lease offering.[10] The practice of making all blocks not currently leased available for bid is called "area-wide leasing," a framework that BOEMRE adopted beginning with lease offering 72 held on May 25, 1983 (prior to that lease sale, only a limited number of geographically grouped blocks were ever made available for a given sale, though these sets of available blocks differed from sale-to-sale).

For each lease offering, BOEMRE announces a reserve bid per block acre, possibly varying by water depth category. For all blocks available in a given lease offering within a given depth category, the reserve bid is constant. Figure 2.2 plots the reserve bid levels by water depth group for the 26 CGM lease offerings conducted

[9]For all lease offerings beginning with 178-1 on March 28, 2001, BOEMRE classifies any block in the 200-399m depth category as shallow.

[10]This is true for CGM and WGM lease offerings, however, BOEMRE has conducted EGM lease offerings only very intermittently, in fact, no EGM lease offerings occurred during 1988-2001.

by BOEMRE during 1983-2008 (the analogous plot for WGM lease offerings during the same time period is essentially identical). In addition to posting a reserve bid, BOEMRE also tries to encourage competitiveness by limiting which consortia can be formed by prospective bidders. Specifically, the largest firms in the industry cannot legally submit joint bids.[11]

Roughly one month prior to a specific lease offering, BOEMRE issues a Final Notice of Sale (FNOS) in the *Federal Register* for potential lessees which stipulates sale-specific information, lease contract requirements, and block availability. Bids are received, opened, and publicly read aloud by midnight on the day of the lease sale. BOEMRE then undertakes an evaluation period to ensure that high bids provide "fair market value" for the leased public resource.[12] It is during this time that BOEMRE can reject a high bid, even if the high bid exceeds the announced reserve (for the 52 lease offerings held during 1983-2008, BOEMRE rejected the high bids for 278 of 10,382 blocks purchased in deep water, or 2.68%).

The prospective leaseholder that submits the highest bid then receives exclusive rights to explore and develop the lease for a term of five years (200-399m), eight years (400-799m), or ten years ($\geq$ 800m) depending on the block's depth category (in parentheses). If the leaseholder does not begin production of hydrocarbons during this term, then the lease is returned to the government to be made available in subsequent auctions.[13] Although, any activity which BOEMRE classifies as "operations," which includes drilling, can extend the lease beyond its primary term (Minerals Management Service (2001), page 50). During the period prior to production, the leaseholder pays an annual rental fee per lease acre which is due on the anniversary of the lease

[11]As the level of concentration within upstream oil production has varied over time, so too has BOEMRE's "List of Restricted Joint Bidders." The membership on the list covering the period from November 1, 2003 through April 30, 2004, however, constitutes a useful snapshot: Exxon Mobil, Shell, BP, TOTAL, Chevron Texaco, and Conoco Phillips.

[12]For the 52 lease offerings conducted during 1983-2008, the average time between successful lease purchase and lease issue was 79 days for deep water blocks.

[13]Leases with eight-year terms are canceled if an exploratory well is not drilled within the first five years (Minerals Management Service (2001), page 50).

becoming effective. Figure 2.3 shows the annual rental fee for the various depth groups and for different years of sale – e.g. for a 5,760 acre lease sold in 1996 in greater than 800m of water, the total rental was $43,200 per year or $432,000 (in nominal terms) over the lifetime of the lease. The leaseholder can avoid these payments by relinquishing the lease, i.e. ending the lease term early by surrendering all rights to the acquired block. BOEMRE then re-offers the block for sale at the next lease offering.

Following the drilling of an exploratory well, the leaseholder is required to submit technical data gathered during the drilling process to BOEMRE (30 CFR 250.116). Upon review of these data, BOEMRE determines whether the well is "qualifying," i.e. whether the well (and by extension, the lease) is "capable of production in paying quantities." Once a lease is deemed producible, BOEMRE assigns it to a "field."[14] Whereas the lease is the administrative unit within the OCS of the Gulf of Mexico, the field is the geologic unit (and can be comprised of more than one lease).

If and only if the leaseholder commences hydrocarbon production on the lease following successful exploration is the lease renewed indefinitely. In this case, BOEMRE waives rental fees and begins royalty collection. For any leases in depths of less than 400m sold prior to 2007, the royalty rate applied to production in the absence of any policy-induced adjustments is 16.67%; the analogous rate for leases in water more than 400m deep is 12.5%. For example, if a lease produces oil, the for each barrel of oil extracted, the leaseholder remits to the federal government the product of the royalty rate and the per-barrel price. Royalty collection, along with the bid and rental payments, constitutes one of the government's mechanisms for capturing rents generated from the production of its leased resources. Finally, once the lease has reached the end of its productive life, it is decommissioned and the block is returned to BOEMRE.

[14]BOEMRE defines a field as "an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both" (61 FR 12027).

2.2.2 The Deep Water Royalty Relief Act

For leases sold during the period 1996-2000 in waters greater than 200m deep in CGM and WGM, the Deep Water Royalty Relief Act conditionally waives royalty payments on hydrocarbon production (Appendix A provides a detailed summary of the provisions and implementation of DWRRA).[15] If τ^r and p_t are the royalty rate and the resource price during the t-th period (of n periods) in calendar year y, for blocks sold prior to the enactment of DWRRA, the leaseholder remits $\tau^r p_t$ per unit of the extracted resource during period t. For eligible deep water blocks sold during 1996-2000, however, the leaseholder remits $\tau_t^r(p_t)p_t$ where

$$\tau_t^r(p_t) = \begin{cases} 0 & \text{if } \bar{p}_y \leq \hat{p}_y \text{ and } \sum q \leq \hat{Q}; \\ \tau^r & \text{otherwise,} \end{cases} \tag{2.1}$$

where $\hat{p}_y$ is the pre-set threshold value and $\bar{p}_y = \sum_{t=1}^{n} p_t$, $\sum q$ represents cumulative production from the specific deep water field, and $\tilde{Q}$ is the suspension volume for the field (where the average and threshold prices are for the commodity that the lease is actually producing). The suspension volume is the maximum quantity of oil or natural gas that can be extracted from the field royalty-free and is meant to limit how large a tax expenditure DWRRA can become. Table 2.1 lists the suspension volumes by water depth in units of BOE ("barrel of oil equivalent" where one BOE equals 5,620 ft.^{3} of natural gas or one barrel of oil).

In words, (2.1) means that for an eligible lease sold during 1996-2000, BOEMRE waives royalty liability on production during calendar year y if the average sale price for a unit of the commodity in that year is below the pre-specified threshold *and* cumulative production from that lease's field does not exceed the suspension volume. If either of these conditions is unmet, then leases sold during 1996-2000 must pay the

[15]Royalty payments are not waived for leases which, otherwise eligible for royalty relief, were subsequently assigned to a field containing at least one lease that produced prior to November 25, 1995 (61 FR 12022). This applies to 11 of 3,540 deep water leases sold during 1996-2000.

same royalty rate as those leases sold prior to the enactment of DWRRA. BOEMRE originally set the price threshold values as $28 per barrel of oil and $3.50 per million Btu of natural gas in 1994. These values have been adjusted each year according to the implicit price deflator for GDP as reported by the Bureau of Economic Analysis.

To summarize: for a producing lease, two calendar years are relevant for determining whether the leaseholder must pay royalties: the vintage year and the current calendar year. In order to be eligible for royalty relief, a lease must have as its vintage year any of 1996-2000. Conditional on eligibility, in order to actually receive a royalty waiver, average price in the current calendar year must fall below a threshold value (ignoring the cumulative production stipulation). Therefore, production from an eligible lease can be royalty-free after calendar year 2000, the last year in which DWRRA eligible leases were sold. In fact, because price thresholds were not exceeded, eligible oil production was royalty-free for every year until 2003 and eligible natural gas production was royalty free during 1996-2000 and 2002. Figures 2.4 and 2.5 and the accompanying tables show the nominal price trends, average nominal prices, and threshold prices for oil and natural gas, respectively, for 1996-2009.

DWRRA provides variation for empirically estimating how royalty liability affects investment decisions. In later sections, (1) I employ cross sectional variation (eligibility for and expectation of royalty relief at time of sale, by sale) to estimate the effects on acquisition and bidding; and (2) I exploit cross sectional and time series variation (eligibility for and expectation of royalty relief at time of sale or any later point) to estimate exploration effects.

2.3 Theoretical Framework

The production of offshore oil and natural gas is preceded by several stages of investment. In chronological order, these are:

1. acquisition: purchase of a lease by submitting the highest (accepted) bid;

2. exploration: observation of deposit size on the lease;

3. development: installation of extraction infrastructure on the lease.

In this section, I construct a simple sequential investment model in order to make precise the mechanisms by which the introduction of a price-conditional royalty policy (e.g. DWRRA) affects the acquisition, bidding, and exploration decisions. The model generates predictions vis-à-vis the policy which I will later test in the data.

2.3.1 Setup

The generation of income from a hydrocarbon lease is preceded by a sequential investment problem. I imagine the firm's problem occurring over four periods: $t = 1, 2, 3, 4$, where each period corresponds to one stage of the firm's decision: acquisition, exploration, development, and production, respectively. In the first stage, at $t = 1$, the firm decides whether or not to acquire the block and how much to bid for it. In the second stage, at $t = 2$, the leaseholder decides to either explore the lease or relinquish it. Then, in the third, at $t = 3$, the firm develops the lease or not depending on the exploration outcome and beliefs about future prices, where the future is $t = 4$. Note that in this framework, I do not model the firm's production decision at $t = 4$.

The goal of the model is to derive an expression for the change in the expected value of a given lease due to the introduction of a price-conditional royalty relief policy (e.g. DWRRA) as a function of the model's underlying parameters. I begin by introducing the parameters, a few of which are already familiar: p_t is the period t resource price; Q is the random variable for the quantity of the resource on the lease where q is the associated realization; τ and τ^r are the corporate income tax and royalty rates, respectively; k_E and k_D are the costs of exploration and development, respectively; ρ is the rental payment for a single period; and $\tilde{r}$ is the rate of return from the next best investment opportunity. Finally, for analytical tractability, I impose the following assumptions:

1. p_t evolves according to a discrete time random walk: $p_{t+1} = p_t + \varepsilon_{t+1}$, with $f(\cdot)$ and $F_\varepsilon(\cdot)$ being the density and distribution functions, respectively, for ε. Furthermore, let $n \cdot \varepsilon \sim F_{n\varepsilon}(\cdot)$.

2. Q can assume one of two possible values:

$$Q = \begin{cases} \tilde{q} & \text{with probability } R; \\ 0 & \text{with probability } 1 - R. \end{cases}$$

3. Firms are risk neutral.

4. Variable costs of production zero.

5. Costs are immediately expensed (fully deductible from income subject to the corporate income tax).

6. Values realized next period are discounted by factor $\beta \equiv (1 + \tilde{r})^{-1}$.

2.3.2 General Optimization

The leaseholder's objective is relatively straightforward: to invest in the current stage if it is "profitable" to do so with the goal of eventually arriving at the production phase. Defining the following objects:

$$\begin{aligned} V_t &= \text{period } t \text{ accounting profits from the investment;} \\ V_t^* &= \text{period } t \text{ economic profits from the investment;} \\ OC &= \text{opportunity cost of the investment,} \end{aligned}$$

I can present the firm's general optimization problem at stage t:

$$\max\{\Pr[V_t > 0]\mathrm{E}[V_t|V_t > 0], OC\}.$$

Therefore, the leaseholder's investment rule in period t is as follows:

$$\text{invest if } \Pr[V_t > 0]\mathrm{E}[V_t|V_t > 0] - OC > 0, \tag{2.2}$$

i.e. invest if expected *economic* profits are positive conditional on accounting profits being positive. This general condition will be applied repeatedly in the section immediately following in order to determine how a price-based royalty policy like DWRRA affects the firm's investment decisions. Due to the fact that the value of the lease at earlier stages of investment depends on the (expected) value of the lease at later stages of investment, I proceed in reverse chronological order in the discussion of optimal investment choices below – first analyzing development, then exploration, and finally acquisition. Although I will not empirically examine the development phase, I must solve for the value of a generic lease at this stage in order to derive expressions for the value of the same lease at earlier stages.

2.3.3 Predictions with and without Price-based Royalty Policy

2.3.3.1 Development

Within this model, if the leaseholder reaches the development phase (at $t = 3$), then the firm necessarily engaged in acquisition at $t = 1$ and then successful exploration at $t = 2$. Therefore $Q = \tilde{q}$. From the application of (2.2), the value of the firm's development problem is:

$$
\begin{aligned}
\mathrm{E}[V_3^*] \quad = \quad & \underbrace{[1-F(\varepsilon_4^*)]\Big[(1-\tau)\big[(1-\tau^r)\beta(p_3+\mathrm{E}[\varepsilon_4|\varepsilon_4 \geq \varepsilon_4^*])\tilde{q}-k_D\big]-\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0} \\
& - \underbrace{\beta\tilde{r}[(1-\tau)k_D+\rho]}_{\text{opportunity cost}} \qquad (2.3)
\end{aligned}
$$

where

$$\varepsilon_4^* \equiv \frac{\rho+(1-\tau)k_D}{\beta(1-\tau)(1-\tau^r)\tilde{q}} - p_3$$

is the period 4 price shock that would have to be realized to make accounting profit at t=3 exactly 0. Furthermore, here and in the rest of this section, it is assumed that the leaseholder observes the current price for the period before having to make the invest or relinquish decision for that period. Note that if expression (2.3) is positive, then the leaseholder should develop the lease.

The above expression is the value of the development problem in the absence of a price-based royalty policy (with price thresholds above which the policy "turns off"), the value of the firm's development problem becomes

$$
\begin{aligned}
\mathrm{E}[V_3^{**}] \quad = \quad & \underbrace{[1-F(\hat{\varepsilon}_4)]\Big[(1-\tau)\big[(1-\tau^r)\beta(p_3+\mathrm{E}[\varepsilon_4|\varepsilon_4 \geq \hat{\varepsilon}_4])\tilde{q}-k_D\big]-\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, royalty}} \\
& + \underbrace{[F(\hat{\varepsilon}_4)-F(\varepsilon_4^*)]\Big[(1-\tau)\big[\beta(p_3+\mathrm{E}[\varepsilon_4|\hat{\varepsilon}_4 \geq \varepsilon_4 \geq \varepsilon_4^*])\tilde{q}-k_D\big]-\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, no royalty}} \\
& - \underbrace{\beta\tilde{r}[(1-\tau)k_D+\rho]}_{\text{opportunity cost}} \qquad (2.4)
\end{aligned}
$$

where $\hat{\varepsilon}_4$ is such that p_4 exactly equals the price threshold at $t=4$, i.e. $\hat{p}_4 = p_3 + \hat{\varepsilon}_4$. For any value of $p_4 > \hat{p}_4$, royalties will be owed on production.[16] If the price shock

[16] It is assumed that $\hat{\varepsilon}_4 > \varepsilon_4^*$ is true.

falls somewhere in $(\varepsilon_4^*, \hat{\varepsilon}_4)$, then royalties are waived. This outcome is reflected in the "no royalty" term above, from which τ^r is missing. Once again, the leaseholder should develop the lease if (2.4) is positive.

The difference between (2.4) and (2.3) provides insight into how a royalty policy like DWRRA affects a leaseholder's development decision. Computing this difference yields:

$$\Delta \mathrm{E}[V_3^*] = \underbrace{[F(\hat{\varepsilon}_4) - F(\varepsilon_4^*)]\Big[\tau^r(1-\tau)\beta(p_3 + \mathrm{E}[\varepsilon_4|\hat{\varepsilon}_4 \geq \varepsilon_4 \geq \varepsilon_4^*])\tilde{q}\Big]}_{\text{expected value of royalty payments saved}} > 0.$$

Notice that the price at $t = 4$ must be high enough so that the investment is profitable but not so high that the threshold is exceeded and royalty payments are therefore owed. This simple model predicts more development due to the policy. Given that $\Delta \mathrm{E}[V_3^*]$ is positive, the royalty policy increases the value of development thus making it more likely that the investment rule for development is satisfied.

2.3.3.2 Exploration

At the exploration stage, the size of the deposit Q is unknown adding more uncertainty to the firm's problem, in addition to the fact that the price that will prevail when production possibly occurs is now further into the future. Again applying (2.2), the value of the firm's exploration problem is:

$$\begin{aligned}
&\mathrm{E}[V_2^*] = \\
&\quad \underbrace{[1 - F_{2\varepsilon}(\mathbf{e}_3^*)]\Big[(1-\tau)\big[(1-\tau^r)\beta^2(p_2 + \mathrm{E}[\mathbf{e}_3|\mathbf{e}_3 \geq \mathbf{e}_3^*])R\tilde{q} - \beta k_D - k_E\big] - (1+\beta)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0} \\
&\quad - \underbrace{\beta\tilde{r}[(1-\tau)k_E + \rho]}_{\text{opportunity cost}}
\end{aligned} \tag{2.5}$$

where $\mathbf{e}_3 = \varepsilon_3 + \varepsilon_4$ and

$$\mathbf{e}_3^* \equiv \frac{(1+\beta)\rho + (1-\tau)(\beta k_D + k_E)}{\beta^2(1-\tau)(1-\tau^r)R\tilde{q}} - p_2$$

is the sum of period 3 and period 4 price shocks that would have to be realized to make accounting profit at t=2 exactly 0. So, if expression (2.5) is positive, then the leaseholder optimally explores.

Of course, interest lies in how the exploration decision is affected by the presence of the price-based royalty policy. With such a policy in place, (2.5) becomes

$$\begin{aligned}
&\mathrm{E}[V_2^{**}] = \\
&\quad [1 - F_{2\varepsilon}(\hat{\mathbf{e}}_3)] \times \\
&\quad \underbrace{\Big[(1-\tau)\big[(1-\tau^r)\beta^2(p_2 + \mathrm{E}[\mathbf{e}_3 | \mathbf{e}_3 \geq \hat{\mathbf{e}}_3])R\tilde{q} - \beta k_D - k_E\big] - (1+\beta)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, royalty}} + \\
&\quad [F_{2\varepsilon}(\hat{\mathbf{e}}_3) - F_{2\varepsilon}(\mathbf{e}_3^*)] \times \\
&\quad \underbrace{\Big[(1-\tau)\big[\beta^2(p_2 + \mathrm{E}[\mathbf{e}_3 | \hat{\mathbf{e}}_3 \geq \mathbf{e}_3 \geq \mathbf{e}_3^*])R\tilde{q} - \beta k_D - k_E\big] - (1+\beta)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, no royalty}} \\
&\quad - \underbrace{\beta\tilde{r}[(1-\tau)k_E + \rho]}_{\text{opportunity cost}}
\end{aligned} \tag{2.6}$$

where $\hat{\mathbf{e}}_3$ is such that p_4 exactly equals the price threshold at $t = 4$ given the current price, p_2, i.e. $\hat{p}_4 = p_2 + \hat{\mathbf{e}}_3$. Again, because the royalty waiver is contingent on the price level at $t = 4$, given the current price, p_2, the two realizations will determine whether there are to be saved royalty payments or not from production. If the sum of the two realized shocks is too large (i.e. $\mathbf{e}_3 > \hat{\mathbf{e}}_3$), then the policy is not in force and royalties are owed.

The difference between (2.6) and (2.5) is:

$$\Delta \mathrm{E}[V_2^*] = \underbrace{[F_{2\varepsilon}(\hat{\mathbf{e}}_3) - F_{2\varepsilon}(\mathbf{e}_3^*)]\Big[\tau^r(1-\tau)\beta^2(p_2 + \mathrm{E}[\mathbf{e}_3|\hat{\mathbf{e}}_3 \geq \mathbf{e}_3 \geq \mathbf{e}_3^*])R\tilde{q}\Big]}_{\text{expected value of royalty payments saved}} > 0.$$

Given that the value of the exploration problem increases with the policy, it becomes more likely that the investment rule will be satisfied. In other words: the model predicts more exploration due to the price-based royalty policy.

2.3.3.3 Acquisition

The first stage of investment is simply the decision whether or not to purchase a lease. Setting aside the price the firm would pay for a given lease (the bid conditional on winning the auction for that lease), the value of the acquisition problem is:

$$\begin{aligned}
&\mathrm{E}[V_1^*] = \\
&\quad [1 - F_{3\varepsilon}(\mathbf{e}_2^*)] \times \\
&\quad \underbrace{\Big[(1-\tau)\big[(1-\tau^r)\beta^3(p_1 + \mathrm{E}[\mathbf{e}_2|\mathbf{e}_2 \geq \mathbf{e}_2^*])R\tilde{q} - \beta^2 k_D - \beta k_E\big] - (1+\beta+\beta^2)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0} \\
&\quad - \underbrace{\beta \tilde{r} \rho}_{\text{opportunity cost}} \qquad (2.7)
\end{aligned}$$

where $\mathbf{e}_2 = \varepsilon_2 + \varepsilon_3 + \varepsilon_4$ and

$$\mathbf{e}_2^* \equiv \frac{(1+\beta+\beta^2)\rho + \beta(1-\tau)(\beta k_D + k_E)}{\beta^3(1-\tau)(1-\tau^r)R\tilde{q}} - p_1$$

is the sum of the periods 2, 3, and 4 price shocks that would have to be realized to make (expected) accounting profit at t=1 exactly 0.

In the presence of the price-based royalty policy, (2.7) becomes

$$\begin{aligned}
&\mathrm{E}[V_1^{**}] = \\
&\quad [1 - F_{3\varepsilon}(\hat{\mathbf{e}}_2)] \times \\
&\quad \underbrace{\Big[(1-\tau)\big[(1-\tau^r)\beta^3(p_1 + \mathrm{E}[\mathbf{e}_2|\mathbf{e}_3 \geq \hat{\mathbf{e}}_2])R\tilde{q} - \beta^2 k_D - \beta k_E\big] - (1+\beta+\beta^2)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, royalty}} + \\
&\quad [F_{3\varepsilon}(\hat{\mathbf{e}}_2) - F_{3\varepsilon}(\mathbf{e}_2^*)] \times \\
&\quad \underbrace{\Big[(1-\tau)\big[\beta^3(p_1 + \mathrm{E}[\mathbf{e}_2|\hat{\mathbf{e}}_2 \geq \mathbf{e}_2 \geq \mathbf{e}_2^*])R\tilde{q} - \beta^2 k_D - \beta k_E\big] - (1+\beta+\beta^2)\rho\Big]}_{\text{expected accounting profits conditional on accounting profits} > 0\text{, no royalty}} \\
&\quad - \underbrace{\beta\tilde{r}\rho}_{\text{opportunity cost}}
\end{aligned} \tag{2.8}$$

Notice that (2.8) is completely analogous to (2.4) and (2.6) and carries the same implications already discussed for those expressions.

Finally, a comparison of (2.8) and (2.7) can be informative with regard to how a policy like DWRRA will affect the acquisition decision. Taking their difference:

$$\Delta\mathrm{E}[V_1^*] = \underbrace{[F_{3\varepsilon}(\hat{\mathbf{e}}_2) - F_{3\varepsilon}(\mathbf{e}_2^*)]\Big[\tau^r(1-\tau)\beta^3(p_1 + \mathrm{E}[\mathbf{e}_2|\hat{\mathbf{e}}_2 \geq \mathbf{e}_2 \geq \mathbf{e}_2^*])R\tilde{q}\Big]}_{\text{expected value of royalty payments saved}} > 0.$$

Not surprisingly, this expression is positive suggesting that all else equal, a given block (a prospective lease) is worth more under the policy. Of course, this is subject to greater uncertainty relative to $\Delta\mathrm{E}[V_2^*]$ (vis-à-vis price) and $\Delta\mathrm{E}[V_3^*]$ (vis-à-vis both price and quantity). Therefore, the model predicts more acquisition. Lastly, under the assumption that the optimal bidding function is invariant to the policy and increasing in the value of the block, the model also predicts higher bids.

A very rudimentary "simulation" of the above model for acquisition yields a value of 0.0669 for $\Delta\mathrm{E}[V_1^*]/\mathrm{E}[V_1^*]$, i.e. the presence of DWRRA increases the value of the lease by roughly 6.69% (I computed this figure by selecting reasonable values for the model variables and then plugging these into both the expression for $\Delta\mathrm{E}[V_1^*]$ and (2.7)).[17] Though this predicted percent change in lease value due to the policy will be small compared to the percent bid effects in Table 2.6 (formally presented and discussed in the Results section), if the optimal bid is a highly nonlinear function of the expected value of the lease, then a small percent increase in the latter could potentially yield a relatively larger percent increase in the former.

2.4 Empirical Analysis

This section of the paper is intended to bridge the gap between the theoretical model detailed in the previous section (which generates predictions regarding DWRRA's effects) and the empirical results presented in the next section (from which conclusions about the policy's actual effects are to be drawn).

2.4.1 Implementation of the Theoretical Model

The firm's acquisition and exploration decisions are determined in general by expressions (2.7) and (2.5), respectively. In both cases, the firm makes the investment if expected economic profits (conditional on positive accounting profits) are positive. Of course, economic profits is a latent variable never observed by the econometrician. The following, however, is observable:

$$e_{it} = \begin{cases} 1 & \text{if } \mathrm{E}[V_2^*] > 0; \\ 0 & \text{if } \mathrm{E}[V_2^*] \leq 0. \end{cases}$$

[17] The set of "reasonable" values for the variables defined at the outset of this section are: $\tilde{r} = 0.05$, $R = 0.1$, $\tilde{q} = 350,000,000$ barrels of oil, $k_e = \$100,000,000$, $k_d = \$500,000,000$, $p_y = \$35$ (the relevant price threshold value), with a current oil price of \$25. Also, the price shock is normally-distributed with mean 0 and variance 100. Lastly, $\tau_r = 1/6$, $\tau = 0.35$, and $\rho = \$43,200$ represent the choices of policymakers. Finally, I ignore the role of the suspension volume entirely in this simulation.

It is clear from the previous section that the expected value of the lease is a function of expectations over price and resource quantity among other variables. Under the assumption that $\mathrm{E}[V_2^*]$ can be expressed as a linear function,

$$
\begin{aligned}
\Pr[e_{it} = 1|\mathbf{X}_{it}] &= \Pr[\mathrm{E}[V_2^*] > 0] \\
&= \Pr[\mathbf{X}_{it}^{'}\Theta + \epsilon_{it} > 0] \\
&= G(\mathbf{X}_{it}^{'}\Theta),
\end{aligned}
$$

where G, the CDF of ϵ_{it}, is assumed symmetric about 0. A completely analogous argument leads to an analogous estimating equation for the acquisition decision.

The linearity assumption for the expected value of the lease yields a general baseline specification for the estimating equations:

$$
\begin{aligned}
y_{it}|\mathbf{X}_{it} &= G(\mathbf{X}_{it}^{'}\Theta) \\
&= G(\alpha_0 + \alpha_1 t + \alpha_2 t^2 + X_{it}^{'}\beta + \gamma p_t + \delta DWRRA_i),
\end{aligned}
\tag{2.9}
$$

where y_{it} represents any one of the outcomes of interest ($\Pr[a_{it} = 1]$, $\Pr[e_{it} = 1]$, or $\mathrm{E}[b_{it}]$, where b is the winning bid) and $G(\mathbf{X}_{it}^{'}\Theta) = \Lambda(\mathbf{X}_{it}^{'}\Theta)$ for acquisition and exploration while $G(\mathbf{X}_{it}^{'}\Theta) = \mathbf{X}_{it}^{'}\Theta$ for bidding. Furthermore, $\mathbf{X}_{it} = [t\ t^2\ X_{it}^{'}\ p_t\ DWRRA_i]$ is the vector of covariates and $\Theta = [\alpha_0\ \alpha_1\ \alpha_2\ \beta^{'}\ \gamma\ \delta]^{'}$ is the vector of parameters to be estimated. The vector of covariates is comprised of t and t^2, the current period and the squared current period; X_{it}, a vector of characteristics for block/lease i at t; p_t, the price of oil at t; and $DWRRA_i$, a dummy variable for whether block/lease i is eligible for DWRRA. Note that the inclusion of t and t^2 as covariates allows for consistent estimation in the presence of some unobservable that is changing non-linearly with time. This polynomial time trend is intended to correct for the influence of (smooth) technological change – which was substantial during the sample period –

and is expected to influence earlier stages of investment, e.g. acquisition, by lowering costs. In some specifications, this time trend is permitted to vary by the block or lease's water depth category (i.e. 200-399m, 400-799m, etc.) because the technological change disproportionately affects deeper blocks.

2.4.2 Data and Data Sources

Having briefly introduced the general specification, I now discuss the actual variables used in the estimating equations and argue for their inclusion given the theoretical model constructed earlier. The source for nearly all of the data is the BOEMRE. Subsequent to acquiring a federal lease, the leaseholder generally must submit a form to the BOEMRE before engaging in any type of activity on that lease. The BOEMRE is required by law to release much of the information contained within the submitted forms without the consent of the lessee (30 CFR 250.197), and makes these data publicly available on its website.[18] The three most important BOEMRE data sets for this analysis are called "Lease Data," "Borehole," and "Blocks." The first of these, "Lease Data," is a lease-level data set that includes characteristics for each of the over 25,000 leases issued in the Gulf of Mexico by the BOEMRE since the 1940s. "Borehole" is a well-level data set containing well characteristics for all wells ever drilled in the U.S. Gulf of Mexico. Important among these is the "spud date" (the date on which drilling commences) and the self-reported type of well (exploratory or development). This information is collected in Form BOEMRE-133, the Well Activity Report, and in Form BOEMRE-123S, the Supplemental Application for Permit to Drill Information Sheet, respectively. Finally, "Blocks" contains latitude and longitude information for the corners of each block in the Gulf of Mexico, with which I am able to determine each block's set of neighbor blocks. Lastly, the daily one-month futures price, alternately known as the daily "nearby delivery month" price (which

[18]http://www.gomr.boemre.gov/homepg/pubinfo/freeasci/freedesc.html.

functions as the spot price) for oil and natural gas is collected from the New York Mercantile Exchange by the U.S. Energy Information Administration (EIA). These data are also downloadable.[19]

With these data, I am able to construct detailed profiles of characteristics for each individual lease over time. Given the interest in estimating the impact of DWRRA on various investment outcomes, I construct the lease histories for underlying variables that relate to the determinants of lease value in the theoretical model – namely, the quantity of the resource (Q), the price of the resource (p), and the costs that must be incurred in order to produce (k_E, k_D). Of these, only price is observable, and so it enters the general estimating equation, (4.6), directly. Of course, given time to build and the fact that the firm cannot extract the deposit instantaneously once the production capital is installed, the spot price that prevails when the firm makes its investment choices will certainly not prevail over the potential period of production. To the extent that oil and natural gas prices evolve as Markov processes, however, the current spot price of oil contains all of the information relevant to constructing expectations of future spot prices. In addition, the use of spot vis-à-vis futures prices is due to the fact that futures contracts for delivery more than two years in advance are characterized by marked thinness, where two years is brief relative to the time needed for offshore oil investment. With regard to costs of exploration and development, the lease's water depth (and depth^2 to reflect a potential nonlinearity in the cost function) enters (4.6) as a time-invariant element of X_{it} for bidding and exploration (it is not available for unleased blocks and thus is not included in the acquisition specification).

The other components of X_{it} are all meant to reflect the firm's beliefs about the block or lease's resource quantity, Q. A number of these variables are measures of the block's characteristics prior to the current lease, denoted as "Own" in Table 2.3, for example. Though Q is not observable by the econometrician or the leaseholder,

[19]From website http://www.eia.gov/dnav/pet/pet_pri_fut_s1_d.htm.

for that matter (prior to exploration), the actions of previous leaseholders on the block in question reveal information about their beliefs regarding Q. A potentially important piece of information regarding an available block is whether or not is has been leased before, which is indicated by the variable "Own: previously leased." This matters because if a block was previously leased, it is indicative of some degree of optimism regarding its potential productivity. These microdata allow, however, allow for further investigation. Again referencing Table 2.3, the symbol $\hookrightarrow$ indicates that the term that follows it is true, as are all lines with that symbol above it, along with the variable on the last line that preceded these variables with $\hookrightarrow$. Thus, for each previously leased block or lease, I record whether it's most recent lease term expired (as opposed to the former lease being relinquished, which would indicate pessimism regarding the lease's possible profitability), whether the lease was itself explored, and conditional on that, whether the leaseholder found hydrocarbons in economically viable quantities (which the BOEMRE refers to as a "qualifying" lease). With the practice of area-wide leasing, I create analogous variables for blocks that are newly available (were leased during the last sale).

Given the often common geology of geographically proximate blocks, lease-specific resource information about a given block j is informative with regard to the amount of the resource on adjacent block i. Given the strategic importance and potential value of pre-exploration lease-specific data, e.g. data from seismic surveys, these variables are generally not observable and thus cannot enter the empirical model. Instead, I employ variables measuring the actions of firms in response to these (unobservable) variables on neighboring leases. These variables are denoted by the "Neighbors" suffix in, for example, Table 2.3. For two blocks to be considered neighbors, their respective centroids (geographic center of the block) must be within five miles of one another. Regarding the "neighbor" variables, all are counts of the number of neighboring blocks/leases for which the condition is true. The absence of the Δ means that the variable counts the number of neighbor blocks for which the condition was true at the time of interest (the lease offering for acquisition and bidding, some month following the lease offering for exploration). The presence of the Δ means that the variable measures the change in the count between the current period of interest and either the lease offering (for exploration estimation) in which the lease was purchased or the lease offering that preceded that one (for acquisition estimation).

2.4.3 Estimation

The estimations of the acquisition, bidding, and exploration models are performed on repeated observations for the same block/lease, meaning that the estimation is pooled. For example, a given lease i will enter the log-likelihood function for exploration for as many time periods as it is still leased but not yet drilled:

$$\begin{aligned}
\Pr[e_{i,\hat{t}+1} = 1 | \mathbf{X}_{\hat{t}+1}] &= \Lambda(\mathbf{X}^{e'}_{\hat{t}+1}\Theta) \\
\Pr[e_{i,\hat{t}+2} = 1 | \mathbf{X}_{\hat{t}+2}, \sum_{t=\hat{t}+1}^{\hat{t}+1} e_{it} = 0] &= \Lambda(\mathbf{X}^{e'}_{\hat{t}+2}\Theta) \\
\Pr[e_{i,\hat{t}+3} = 1 | \mathbf{X}_{\hat{t}+3}, \sum_{t=\hat{t}+1}^{\hat{t}+2} e_{it} = 0] &= \Lambda(\mathbf{X}^{e'}_{\hat{t}+3}\Theta) \\
&\vdots \\
\Pr[e_{i,\hat{t}+T} = 1 | \mathbf{X}_{\hat{t}+T}, \sum_{t=\hat{t}+1}^{\hat{t}+T-1} e_{it} = 0] &= \Lambda(\mathbf{X}^{e'}_{\hat{t}+T}\Theta),
\end{aligned}$$

where $t = \hat{t}$ represents the period of acquisition. The equations above represent the case where lease i is never explored before the last period (exploration could still possibly occur at $t = \hat{t} + T$). Alternatively, if lease i was explored in period $t = \hat{t} + 3$, then the lease would have exited the exploration sample after three periods. Finally, in the empirical models for each outcome, errors are clustered on the lease or block identifier, i.e. the empirical model permits the errors to be correlated across observations within the same block or lease.

2.5 Results

The parameters estimates presented in this section are generated using samples of deep water blocks and leases relating to the 34 CGM and WGM lease offerings held during the years 1984-2000. The earliest of these, CGM Sale 81, was held on April 24, 1984 while the latest, WGM Sale 177, was held on August 28, 2000. The sample corresponds approximately to the beginning of area-wide leasing and exactly to the end of DWRRA.[20] I have excluded blocks available and leases sold in lease offerings held after 2000 because BOEMRE offered a modified (and less generous) version of DWRRA for leases sold in those auctions.

2.5.1 Acquisition

Table 2.3 provides descriptive statistics for the covariates in the acquisition model for the relevant sample. The sample is comprised of all deep water blocks available in at least one lease offering for the CGM or WGM planning areas during the years 1984-2000. This is an unbalanced panel comprised of 9,054 individual blocks and 124,564 block-years ("-years" is appropriate because there is one sale per planning area per year). It is characterized by attrition (once a block is sold, it leaves the panel), late entry (if a block was leased at the time of the 1984 lease offering but then expired or was relinquished prior to the year 2000 lease offering), and re-entry (if a block was acquired at the 1984 lease offering or later but then expired or was relinquished prior to the year 2000 lease offering). Therefore, the panel is only balanced for the 4,360 blocks that were available in the 1984 lease offerings and then never subsequently

[20]BOEMRE commenced area-wide leasing with CGM Sale 72 held on May 25, 1983, but I exclude this lease offering from the sample, along with WGM Sale 74 held on August 24, 1983, because I have not found reliable data regarding which blocks were made available in the last sales preceding the advent of area-wide leasing, information that is necessary for constructing many of the covariates.

sold through the year 2000 lease offerings. These unleased block-years number 74,120 (approximately 59.5% of the sample). Finally, of the 124,564 block auctions held during this period, only 6,140 (4.93%) resulted in the sale of the block.

Figure 2.6 suggests an effect on the acquisition of deep water blocks due to DWRRA. The pooled probability of acquisition both before (for lease offerings held during 1984-1995) and during DWRRA (for lease offerings held during 1996-2000) are presented as dashed lines at 0.0291 and 0.1121, respectively. Although the difference of 0.083 in unconditional probabilities hints at an effect of the policy, it however masks variation in the probability of acquisition both before and during the policy. For example, after the first three years that DWRRA is in force, the probability of acquisition drops to the level in 1995, the last year prior to the policy being applied.

Table 2.4 lists estimated average marginal effects and finite differences for the baseline empirical model for the acquisition decision. Note that for this model, I have added one additional macro-level variable to specification (4.6) in order to reflect the general climate for investment. The variable, the proportional "output gap" represents the percent difference between predicted and actual GDP.[21] Inclusion of this variable is justified on the grounds that a weaker economy (signified by a larger output gap) would bode poorly for the profitability of future offshore oil projects, which necessarily begin with leasing.

Results are reported in Table 2.4 for three different specifications, which differ in how they handle the trending unobservable – not at all in column (1); using a polynomial time trend in column (2); and using three, one for each depth category, polynomial time trends in column (3). Both a comparison between the estimated finite differences in acquisition due to DWRRA and the difference in unconditional probability of acquisition along with an examination of the estimated coefficients for

[21] The actual variable equals (predicted GDP - GDP)/(predicted GDP) where "predicted GDP" is estimated on a quarterly basis by the Congressional Budget Office and GDP is computed by the Bureau of Economic Analysis.

the polynomial trends point to the specification in column (1) as being preferred. First, the estimated finite difference in column (1) is 0.074 (i.e. the presence of DWRRA increases the probability of lease acquisition by 7.4 percentage points), which is much more in line with the observed difference of 0.083. In contrast, the models with time trends predict effects of the policy nearly three time larger than the difference in unconditional probabilities. Second, for all quadratic time trends estimated in column (2) and column (3), the linear term has a positive coefficient while the squared term has a negative coefficient. This implies that as time passes, the effect of the changing unobservable (i.e. technology) is attenuating and then eventually becoming increasingly negative. These estimated effects are not intuitively consistent with the improved technology that occurred in offshore exploration and production during the sample period.

Given the above discussion, I focus on the estimates in column (1). The empirical model is meant to approximate the theoretical model in that the potential leaseholder makes the choice to acquire the lease (or not) based on the most current information available to it regarding future resource price and quantity. Observable (to the econometrician) information about resource quantity is derived from the block's own history (the "Own" variables, which are true at the time of purchase and unchanging after) and from outcomes on neighboring leases (the "Neighbor" variables, which can vary after the lease is purchased). Regarding the latter group of variables, "# leased" is less an outcome, but rather reflects the possibility for the receipt of additional information from new drilling outcomes. Finally, conditional on the prospective block being available in the previous lease offering, the "Neighbors: $\Delta\ldots$" variables reflect the change in the stock of information from the set of neighboring blocks since that last lease offering. In the presence of these determinants of potential lease value as suggested by theoretical model, the DWRRA eligibility indicator is meant to quantify the change in the probability of acquisition controlling for their effects.

Regarding the acquisition decision, newly available blocks (due to expiration of the previous lease) that were unexplored are attractive prospects, though similar explored blocks that were not "qualifying" are not (see section 2.1 for discussion of qualifying leases). Intuitively, both blocks were deemed valuable enough to purchase, sending a positive signal to the potential buyer, but then the non-qualifying explored block was revealed to be of lower quality in the exploration outcome. In the broader set of previously held blocks that are not newly available, previously relinquished blocks are also attractive purchases (this seems counterintuitive, but might have more to do with blocks from just-expired leases being repurchased immediately). Finally, changes and the prospect of changes in information on neighboring blocks also positively influence lease purchase. Controlling for the observables included in the model, the mean estimated marginal effect on the probability of acquisition for a block being sold while DWRRA was in force is 7.4 percentage points. Thus, consistent with the theoretical prediction, the prospect of royalty liability being waived makes it more likely that a given block will be purchased.

2.5.2 Bidding

Table 2.5 provides descriptive statistics for the covariates in the bidding model for the relevant sample. The sample is comprised of all deep water leases sold in any CGM or WGM planning area lease offerings held during the years 1984-2000.[22] There are 6,140 such leases, of which 3,401 were sold while DWRRA was in force (1996-2000). This collection of covariates is almost identical to those used in the acquisition specification, except I now include the lease's water depth (in 1000s of feet) and squared water depth and omit the output gap.

Figure 2.7 attempts to establish suggestive evidence of an effects on bids of the

[22] By "sold," I mean that the high bid was not rejected and winning bidder actually chose to "take delivery of" the issued lease. Though rare, winning bidders can decide not to take the lease for which they submitted an accepted bid.

policy change. This is complicated somewhat by the fact the reserve bids vary over the sample period (see Figure 2.2). While I easily control for this in estimating the regressions, I deal with variable reserve bids here but by presenting mean values for the bid *minus the reserve bid*, by year. A further complication arises in that the mean bid for the period prior to DWRRA is highly dependent on the years included. Noting that the dotted lines in Figure 2.7 represent the pooled mean bid (in 2009 $) both before and during DWRRA, inclusion of years 1984-1986 in the pre-DWRRA group (which already includes 1987-1995) changes the treatment effect as estimated by the difference in pooled mean bids from $576,496 to -$35,196 (a 95.5% increase to a 2.9% decrease). This is equivalent to moving from the lower to upper panel of Figure 2.7 (recall that the estimation sample used for the regressions is comprised of all deep water leases sold in all years 1984-2000).

Table 2.6 lists estimated average marginal effects and finite difference for the baseline empirical model for the bidding decision. The differences between the three columns is analogous to the difference in the Table 2.4; in addition all specifications include dummies for the posted per-acre reserve bid, which differed between lease offerings in the sample (see Figure 2.2). The empirical bidding model is meant to estimate the effects of observable (to the econometrician) lease characteristics at the time of sale on the winning bid paid for the lease. The entries in 2.6 are semi-elasticities as the dependent variable is the natural logarithm of the winning bid in 2009 dollars. Focusing on specification (3), the possibility of royalty relief increases the winning bid by approximately 60%. This is consistent with both the model and our intuition, as the lease is more valuable in expectation (given certain realizations of price), so bidders pay more for it.

Quantifying the policy change's treatment effect on the winning bid is complicated by fact that acquisition is also affected by DWRRA. We would expect the estimated effect to be less than the true effect as the flood of marginal leases pulls down the average bid (recall the relatively large estimated effect of DWRRA on acquisition). A rather coarse way of dealing with this is to assume that the leases receiving the highest bid are the most inframarginal, and then estimate the effects using quantile regression at various quantiles. These results are shown in Figure 2.8: the semi-elasticity for DWRRA is (almost) monotonically increasing through the quantiles and surpasses the estimated OLS semi-elasticity at approximately the 55th quantile.

2.5.3 Exploration

Table 2.7 provides descriptive statistics for the data used to estimate the empirical exploration model. The unit of analysis is the lease-month, with the earliest lease-month corresponding to June 1984 (the earliest date for which any lease purchased at CGM Sale 81 became effective) and the latest lease-month corresponding to June 2010. A lease, specifically a deep water lease sold anytime during the period 1984-2000, enters the sample as soon at it is purchased and exits the sample when an exploratory well is drilled or when it is no longer possible for the leaseholder to drill an exploratory well (i.e. when the lease expires or is relinquished). The first variable in 2.7, "Drilled," is the dependent variable in the subsequent logit regressions and it indicates whether an at-risk lease has an exploratory well drilled (for the first ever) in the current month. Of the 6,140 leases in the sample, 133 (2.16%) are right-censored. Finally, the average time at risk (measured in months) in the sample for leases with five-year and ten-year lease terms is 55.6 and 97.9 months, respectively.

Table 2.2 compares the number of leases acquired and explored by depth zone and DWRRA status. The strong influence of the change in royalty treatment on the acquisition decision is clear for the $\geq$ 800m category (which accounts for over 75% of acquired leases): the average number of leases sold per lease offering jumps from 72.2 to 291.4 with the advent of DWRRA. Continuing to focus on the $\geq$ 800m category, despite the fact that the number of leases that ever has an exploratory well increases with the change in royalty treatment, the probability of an exploratory well conditional on royalty treatment falls from 0.116 to 0.072. With the increase in the numerator of the probability, the sharp drop in the probability of the lease being explored is due to the strong acquisition effect. In this way, the large acquisition effect causes the influence of DWRRA (and its more favorable royalty terms) to appear to negatively affect subsequent investment *if* the investment measure is conditioned on acquisition.

The influence of the large acquisition effect is also clear from the estimates in 2.8. I focus on specification (1) which includes variables representing the stock of aggregate information about neighbor blocks/leases at the time the lease of interest is sold, and also measures of how those information stocks have changed up to the current month. Furthermore, the influence of neighbor information is allowed to vary depending on whether neighboring leases have their vintages during the DWWRA period, 1996-2000, or not (I allow for differential effects because the more favorable royalty treatment of DWRRA lowers the threshold for acquisition, exploration, etc. and thus these actions need not carry the same information as they would for pre-DWRRA leases). Estimated coefficients for the neighbor variable stocks are provided in the second panel of Table 2.8. Turning to the first panel of Table 2.8 (which includes coefficients for all variables related to the lease-month, itself, and prices), the mean marginal effect of DWRRA eligibility (summing the mean marginal effects for both "DWRRA Eligible" and "DWRRA Eligible × Spot Price" where the latter is computed following Ai and Norton (2003)) on the per-month drilling hazard is -0.00019. The interaction term is included because of the price thresholds that are a part of DWRRA: recall that royalty liability is reinstated if the average oil or natural gas in the calendar year exceeds a threshold. Therefore, we expect that at high prices, any effect of DWRRA on the drilling hazard will become more negative (as DWRRA eligible leases becomes less valuable relative to non-DWRRA leases with the price increase). Although the estimated mean marginal effect of DWRRA eligibility is absolutely small, the probability of an exploratory well being drilled in a given month is also a very small number (recall from Table 2.7 that the unconditional hazard is 0.0013) and thus this treatment effect can be considered relatively large.

While the above estimate is informative, the dependence on acquisition stymies estimation of any effect that carries implications for efficiency (e.g. we do not believe that a lower royalty will lead to *less* investment, all else equal). In order to get an estimate that reflects the change in exploratory drilling that, though technically conditional on acquisition, is unaffected by the amount of acquisition that precedes it, I abandon the probability of exploratory drilling in favor of a count: the number of leases drilled. Table 2.2 provides suggestive evidence that DWRRA increased the occurrence of exploratory drilling. In order to get a causative effect of the change in royalty status on exploratory drilling, I propose the following estimator:

$$\frac{\%\Delta \mathrm{E}[N_e]}{\Delta D} = \left[1 + \frac{\%\Delta N_a}{\Delta D}\right]\left[1 + \frac{\%\Delta F(T)}{\Delta D}\right] - 1, \tag{2.10}$$

which is derived and made operational in Appendix B. In (2.10), N_e is the number of explored leases, N_a is the number of acquired leases, and "D" is shorthand for DWRRA status. Plugging in estimates already discussed yields:

$$\left(\widehat{\frac{\%\Delta \mathrm{E}[N_e]}{\Delta D}}\right) = (1 + 1.89)(1 - 0.1458) - 1 = 1.504,$$

meaning that the expected number of exploratory wells is estimated to increase by 150% due to removal of the royalty.

2.5.4 Some Closing Remarks

Although the price of oil looms large in the model and intuitively is an important determinant of investment, its estimated coefficients are quantitatively small or statistically insignificant in the empirical models for acquisition, bidding, and exploration. At the same time, the coefficient estimates for the DWRRA indicator imply that this policy affects these investment decisions, this despite the fact that DWRRA superficially resembles a price change, as it changes the percentage royalty assessed on revenue. A possible explanation for this lies in the fact that oil is produced from many different geographic sources, but DWRRA is applied in nonuniform way across these sources. Specifically, DWRRA favors oil investment and production opportunities in the deep waters of the U.S. Gulf of Mexico *only*, while a price increase, for instance, affects all opportunities in approximately the same positive manner. Thus, DWRRA made investment in deep water prospects in the U.S. Gulf of Mexico differentially more attractive in a way that an equivalent price increase could not.

Finally, recall that the empirical model of exploration relies heavily on variables measuring activity on neighboring leases. An important finding in the public finance literature is that neighboring (broadly defined) political jurisdictions' (U.S. states, in the research in question) expenditures are correlated even after controlling for observable and unobservable own and neighbor characteristics (Case et al. (1993)). To the extent that hydrocarbon leases resemble political jurisdictions in arguably important ways, then the estimated effect of DWRRA on exploration might be inconsistent in that it will absorb the "natural" effect of neighbor's activities on one another that prevails whether the policy is in force or not. To completely address this concern would require an instrument, where unfortunately none is available.

2.6 Conclusion

Using administrative data compiled by the U.S. Department of Interior from leases in the Gulf of Mexico, this paper estimates the effects of a potential royalty suspension on the acquisition, exploration, and bidding behavior of firms. Exploiting variation in the royalty rate provided by the Deep Water Royalty Relief Act (DWRRA), I show that a temporary suspension of royalty liability increases the probability of block acquisition by an average of 193%, lowers the probability that a lease is ever drilled during its term by 14.5%, and increases the expected number of leases explored by 150%. In addition, the average winning bid paid for a lease increases by 60%. The favored interpretation is that these estimates, taken together, imply that firms greatly expanded their lease holdings in response to the lower potential royalty. With only a finite set of potential leases in the Gulf of Mexico, however, these new (and marginal) holdings were of lower quality, on average, than those sold prior to DWRRA, and therefore less likely to be drilled. That the leases sold with DWRRA vintages have a lower probability of drilling is borne out in the data. The combination of estimated values suggests that firms reacted to the prospect of lessened royalty liability by engaging in much more speculative investment at the acquisition stage, but also by increasing the absolute number of leases in which they invested in subsequent phases.

Page 42 of the document "Oil and Gas Leasing Procedures Guidelines" includes the following passage: "In administering the offshore oil and gas leasing program, the Secretary of the Interior is required by law to see that the Government receives a fair return for the lease rights granted and the minerals conveyed" (Minerals Management Service (2001)). Most citizens and policymakers would likely agree with this statement – that private sector firms should pay *something* for the right to profit from resources extracted from parcels of publicly-owned land, which technically belong to the citizenry – but would be unprepared to answer what is the "best" way to accomplish such rent sharing from the standpoint of administrative simplicity, efficiency, etc. The challenge in comparatively evaluating different frameworks for rent capture has much to do with the lack of estimates for firm responses to different royalty rates, for example. Although the particular form of DWRRA precludes an empirical analysis to match the theoretical evaluation of leasing policy offered in Leland (1978), this paper estimates quantitatively large responses in drilling and bidding to the prospect of a lower royalty rate. Together these suggest that a movement away from the royalty might improve efficiency without necessarily sacrificing revenue.

2.7 Appendix: The Deep Water Royalty Relief Act

On November 28, 1995, President Bill Clinton signed Public Law 104-58, which included three sections - 302, 303, and 304 - which together comprised the substantive portions of the Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA).[23] These sections constituted amendments to section 8 of the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1337. Section 302 clarifies the authority of the Secretary of the Interior to reduce or eliminate royalties on current or future production from *existing* leases (at the time of DWRRA's enactment), whether producing or not-yet-producing, for the sake of encouraging extraction. Section 302 also provides that new production from *existing* leases (at the time of DWRRA's enactment) on blocks at water depths greater than 200m could qualify for royalty suspension if, following application by the leaseholder, the Secretary of the Interior determined that production was sufficiently marginal that it would not occur without the removal of royalty liability. This section also states that continued royalty relief at a point in time is conditioned on the total quantity of oil or natural gas cumulatively extracted and the average price of the resource during that calendar year. Section 303 puts forth a new bidding system mandating that the Secretary of the Interior offers *new* blocks with royalty suspensions under stipulations to be determined by the Secretary. Finally, section 304 requires that all blocks in waters greater than 200m deep that are offered during the five-year period beginning with the enactment of DWRRA be sold under the bidding system laid out in section 303. Furthermore, it specifies minimum suspension volumes (the maximum amount of royalty-free production that can be produced from the unit to which it is applied). All of these provisions applied only to

[23] Davis and Neff (1996) provides a thorough account of the legislative history of DWRRA.

blocks lying west of 87 degrees, 30 minutes West longitude (in either the Central Gulf of Mexico planning area or the Western Gulf of Mexico planning area, effectively).

The vagueness of the DWRRA provisions of Public Law 104-58 necessitated the release of subsequent rules so that the act could be implemented in the first sale to which it was meant to apply: lease offering 157 on April 24, 1996. A Final Rule issued on February 2, 1996 clarified section 303 (61 FR 3800). Specifically, it further amended OCSLA so that royalty liability could be contingent on the price level of oil or natural gas and so that the conditions under which royalties would be owed could be stipulated in the final notice of sale (FNOS). An Interim Rule issued on March 25, 1996 clarified that suspension volumes (defined in subsection 4.1 above) for new leases would be applied to the *field* rather than to the individual lease and also specified which new leases would be eligible for royalty relief (61 FR 12022). These eligibility criteria, along with specific oil and natural gas price thresholds above which royalty liability would be in force, were printed in the FNOS for lease offering 157.

2.8 Appendix: Derivation of Estimator for $\mathbf{E}[N_e]$

The expected number of explored leases through t periods, N_t^e, can be expressed as

$$\mathrm{E}[N_t^e] = N^a F(t)$$

where N^a is the number of acquired leases and $F(t)$ is the CDF for t^e, the period when exploratory drilling occurs. Letting D be a dummy variable indicating DWRRA eligibility, then the marginal effect of DWRRA on $\mathrm{E}[N_e]$ is

$$\frac{\Delta \mathrm{E}[N_e]}{\Delta D} = \left[N_a + \frac{\Delta N_a}{\Delta D} \right] \left[F(T) + \frac{\Delta F(T)}{\Delta D} \right] - N_a F(T). \tag{2.11}$$

Note that (2.11) can be converted to a semi-elasticity by dividing both sides by $N_a F(T)$:

$$\begin{aligned}
\frac{1}{N_a F(T)} \cdot \frac{\Delta \mathrm{E}[N_e]}{\Delta D} &= \frac{1}{N_a}\left[N_a + \frac{\Delta N_a}{\Delta D}\right]\frac{1}{F(T)}\left[F(T) + \frac{\Delta F(T)}{\Delta D}\right] - 1 \\
\leftrightarrow \frac{(\Delta \mathrm{E}[N_e]/\mathrm{E}[N_e])}{\Delta D} &= \left[1 + \frac{(\Delta N_a/N_a)}{\Delta D}\right]\left[1 + \frac{(\Delta F(T)/F(T))}{\Delta D}\right] - 1 \\
\leftrightarrow \frac{\%\Delta \mathrm{E}[N_e]}{\Delta D} &= \left[1 + \frac{\%\Delta N_a}{\Delta D}\right]\left[1 + \frac{\%\Delta F(T)}{\Delta D}\right] - 1.
\end{aligned}$$

The final line of the derivation reveals that the semi-elasticity of the expected number of explored leases is a function of two other semi-elasticities: for the number of leases acquired and for the CDF for the time of first exploratory well. In order to operationalize this expression, we require estimates for the two semi-elasticities that compose it. These are discussed in turn below.

Having defined t^e as the period when exploratory drilling occurs, let t^a represent the period when lease acquisition occurs. The discrete-time hazard for exploratory drilling is defined as

$$\lambda(t) \equiv \Pr[t^e = t | t^e \geq t];$$

in words: the probability that exploratory drilling occurs at t given that it has not occurred prior to t. Note that the discrete-time survivor function for drilling can be expressed as

$$S(t) = \Pr[t^e \geq t] = \prod_{s=t^a+1}^{t-1} (1 - \lambda(s)).$$

Given the identity $S(t) + F(t) = 1$, we have

$$F(t) = \Pr[t^e < t] = 1 - \prod_{s=t^a+1}^{t-1} (1 - \lambda(s)),$$

which is the CDF for t^e. Defining T as either

1. the period during which drilling occurs, conditional on it having occurred; or

2. the last period during which drilling can occur, conditional on it not having occurred; or

3. the last observed period during which drilling is possible, conditional on it not having occurred (applies to leases for which the lease term is right-censored),

and evaluating the CDF at this point in time, yields

$$F(T) = 1 - \prod_{s=t^a+1}^{T-1} (1 - \lambda(s)).$$

This is the probability that a lease is ever drilled during its (observed) lifetime.

The semi-elasticity of DWRRA for the probability that a lease is ever drilled can be expressed in terms of the marginal effect of DWRRA on the hazard in the following way:

$$\begin{aligned}
\frac{\%\Delta F(T)}{\Delta D} &= \frac{(\Delta F(T)/F(T))}{\Delta D} \\
&= \frac{\left[1 - \prod_{s=t^a+1}^{T-1}(1 - [\lambda(s) + \frac{\Delta\lambda(s)}{\Delta D}])\right] - \left[1 - \prod_{s=t^a+1}^{T-1}(1 - \lambda(s))\right]}{1 - \prod_{s=t^a+1}^{T-1}(1 - \lambda(s))} \\
&= \left[\frac{1 - \prod_{s=t^a+1}^{T-1}(1 - \lambda(s) - \frac{\Delta\lambda(s)}{\Delta D}])}{1 - \prod_{s=t^a+1}^{T-1}(1 - \lambda(s))}\right] - 1.
\end{aligned}$$

The estimator for this semi-elasticity is

$$\left(\frac{\widehat{\%\Delta F(T)}}{\Delta D}\right) = \sum_{i=1}^{N_a} \left(\left[\frac{1 - \prod_{s=t_i^a+1}^{T_i-1} (1 - \hat{\lambda}_i(s) - \frac{\Delta \lambda_i(s)}{\Delta D})}{1 - \prod_{s=t_i^a+1}^{T_i-1} (1 - \hat{\lambda}_i(s))} \right] - 1 \right), \tag{2.12}$$

where

$$\hat{\lambda}_i(t) = \hat{\Pr}[t_i^e = t | t_i^e \geq t; X_{it}] = \Lambda(X_{it}' \hat{\beta})$$

from the empirical model for exploratory drilling.

Estimates for components of the average treatment effect of DWRRA eligibility on the hazard for exploratory drilling, $\mathrm{E}\left[\frac{\Delta \lambda}{\Delta D}\right]$, are provided in Table 2.8. The "total" effect of DWRRA eligibility on the hazard is the sum of the "direct" effect reported for "DWRRA eligible" and the interaction effect for "DWRRA eligible $\times$ Spot Price" reported in Table 2.8. With the presence of the interaction with the spot price of oil, the ATE is determined by the unreported estimated coefficients for "DWRRA eligible," "DWRRA eligible $\times$ Spot Price," and "Spot Price - Oil," along with the actual data, itself (Ai and Norton (2003)).

Turning now to the estimate for $\frac{\%\Delta N_a}{\Delta D}$, note that effect of DWRRA status on the probability of acquisition (if not the number of acquired blocks) is provided in Table 2.4. Letting $\Pr[a_{it} = 1|D]$ represent the probability of block acquisition conditional only on DWRRA status, note that this probability is directly observable. This figure is an input to the semi-elasticity estimator:

$$\left(\frac{\widehat{\%\Delta N_a}}{\Delta D}\right) = \frac{\left(\frac{\Delta \Pr[a_{it}=1|X_{it}]}{\Delta D}\right)}{\Pr[a_{it} = 1|D = 0]}. \tag{2.13}$$

Insertion of (2.12) and (2.13) in (2.10) allow for ready estimation of the percentage change in the expected number of explored leases.

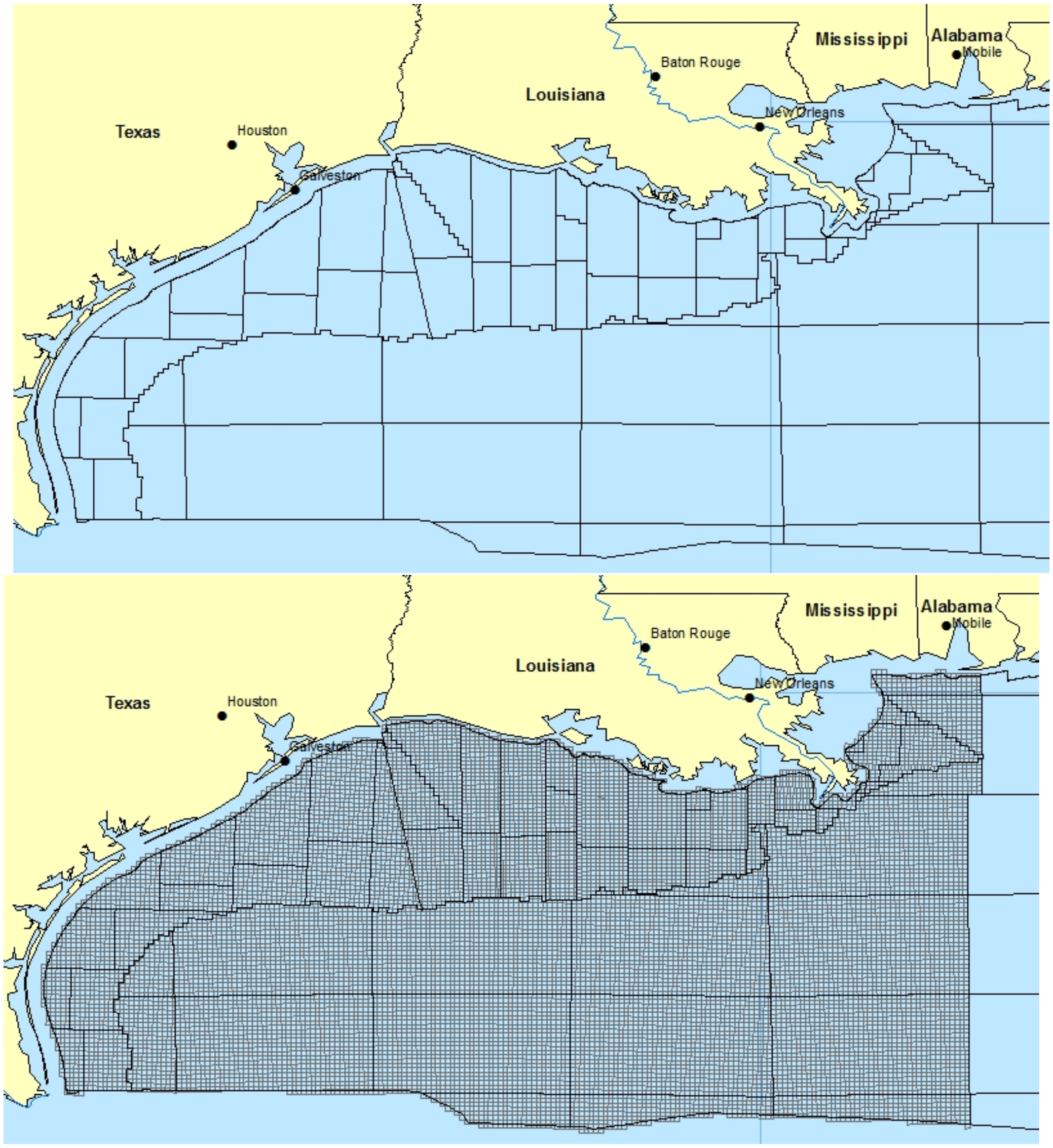


Figure 2.1: Area (upper) and block (lower) maps for CGM and WGM.

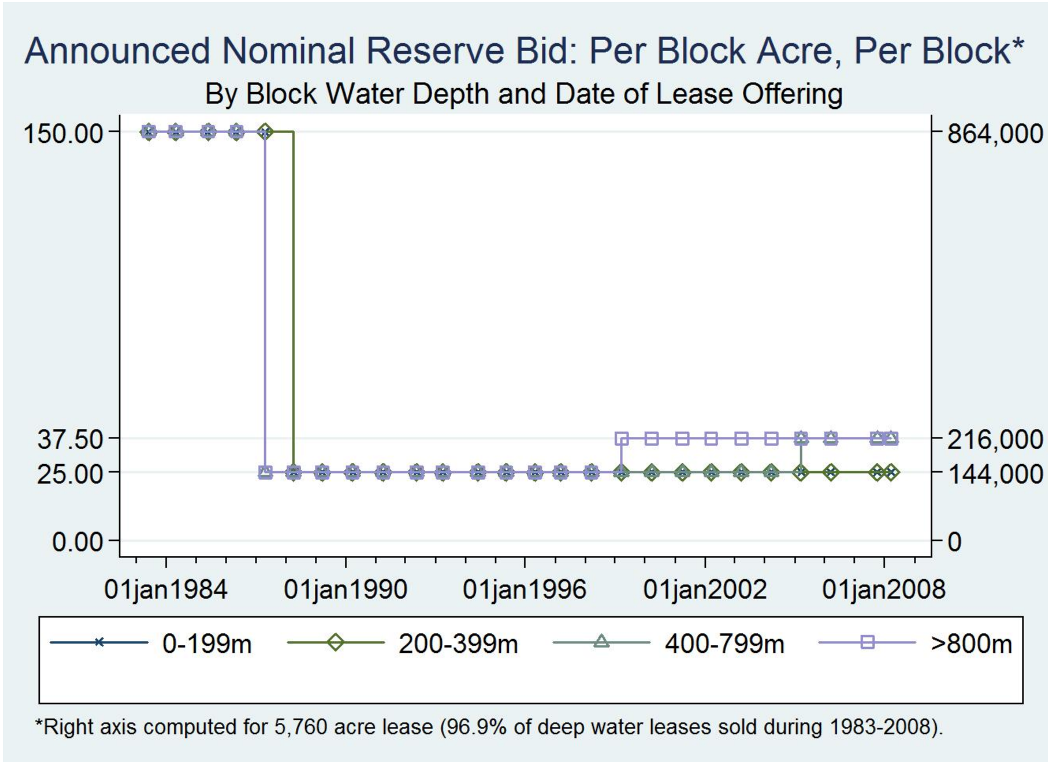


Figure 2.2: Reserve bids for CGM lease offerings, 1983-2008.

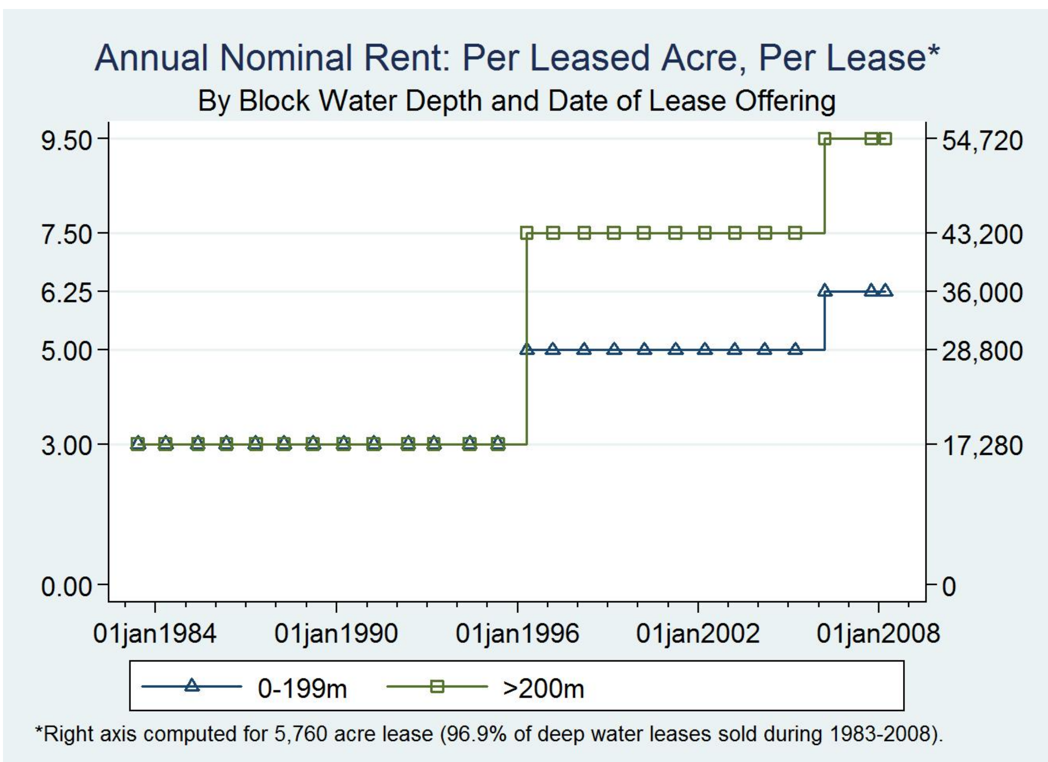


Figure 2.3: Annual rent for CGM lease offerings, 1983-2008.

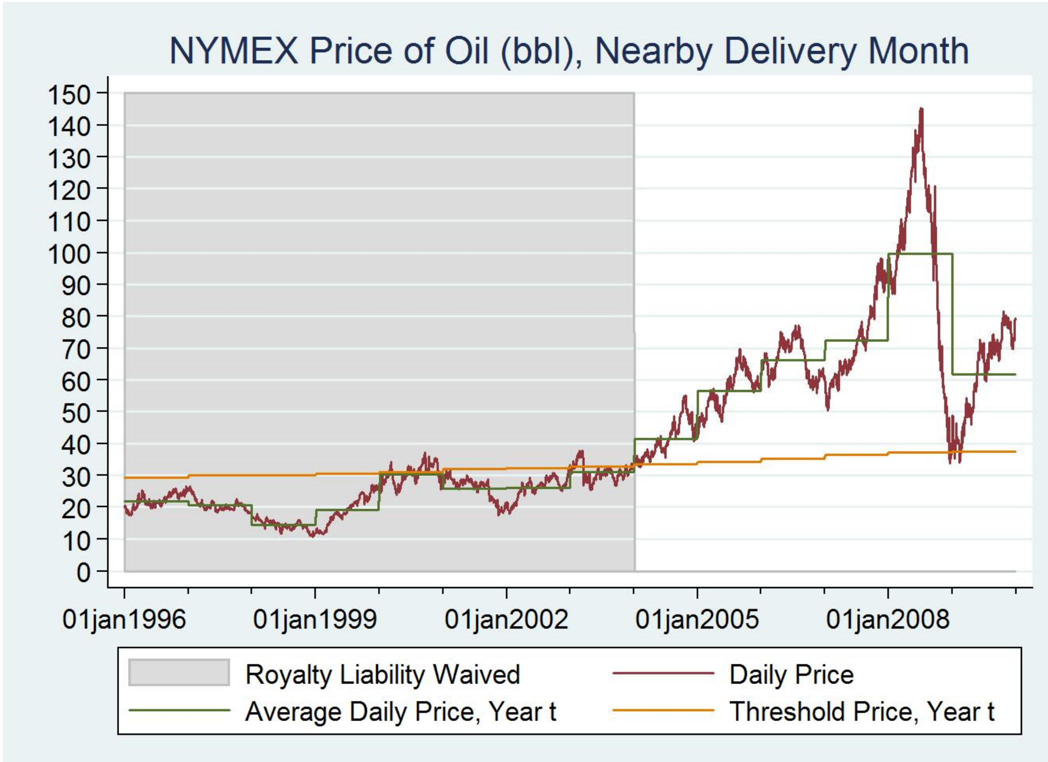


Figure 2.4: Oil prices, 1996-2009.

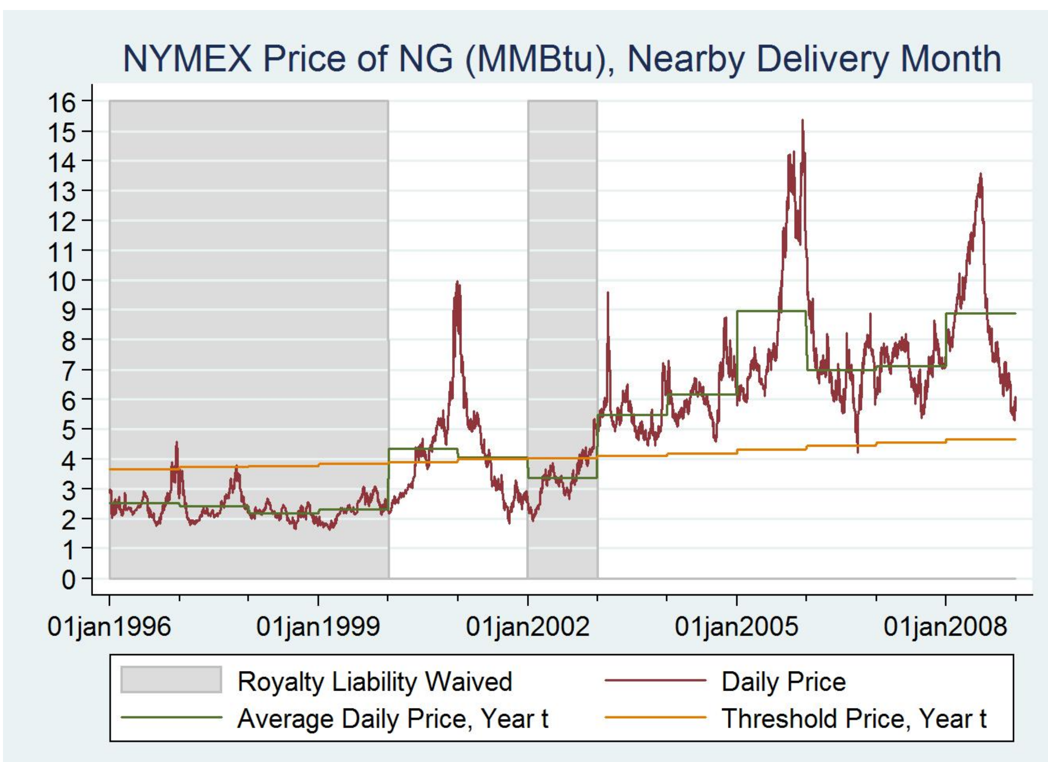


Figure 2.5: Natural gas prices, 1996-2009.

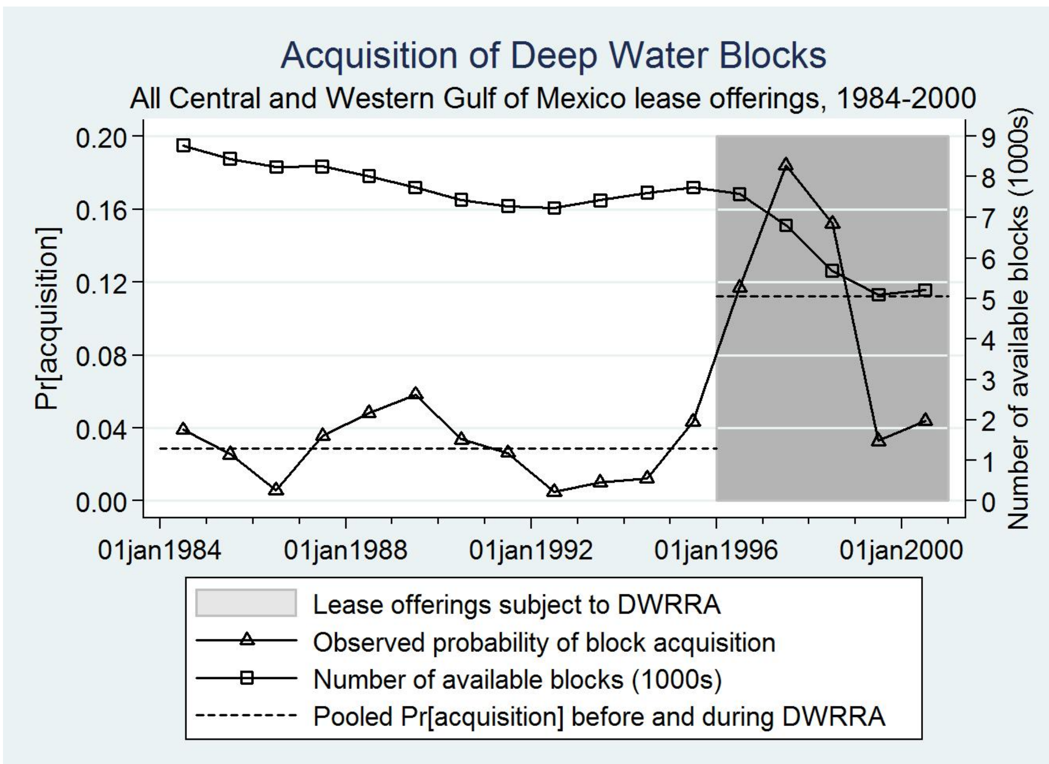
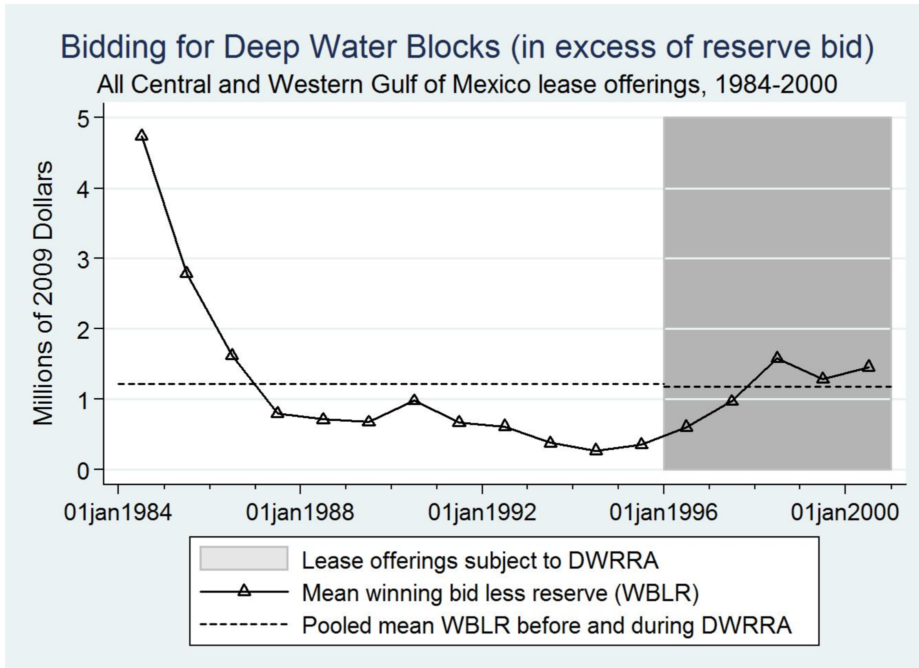


Figure 2.6: Acquisition of deep water leases, 1984-2000.



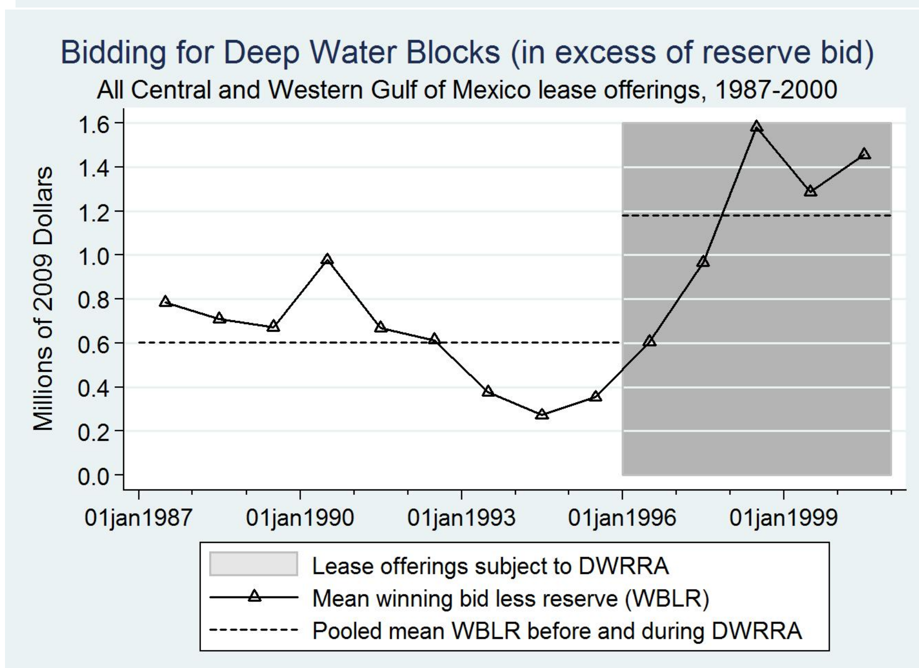


Figure 2.7: Bidding for deep water leases, 1984-2000.

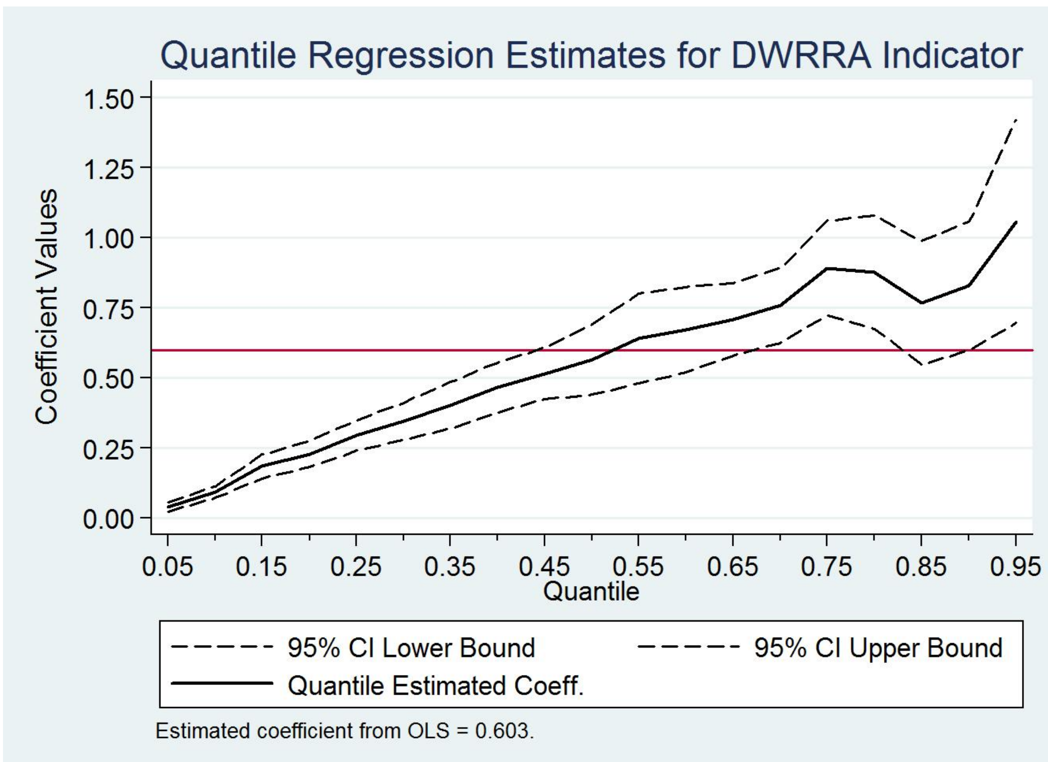


Figure 2.8: Quantile regression semi-elasticity estimates for DWRRA indicator.

Water depth category for field	**Suspension volume (in barrels of oil equivalent)**
0-199m	*Not eligible for DWRRA.*
200-399m	17.5 million.
400-799m	52.5 million.
$\geq$ 800m	87.5 million.

Table 2.1: DWRRA suspension volumes.

		Pre-DWRRA (24 lease offerings)		**DWRRA** (10 lease offerings)	
		N	*Average*	*N*	*Average*
200-399m	Leases Acquired	383	16.0	168	16.8
	Leases Explored	103	4.3	24	2.4
	Exploration Rate	0.269		0.143	
400-799m	Leases Acquired	633	26.4	309	30.9
	Leases Explored	118	4.9	46	4.6
	Exploration Rate	0.186		0.149	
$\geq$800m	Leases Acquired	1,733	72.2	2,914	291.4
	Leases Explored	201	8.4	211	21.1
	Exploration Rate	0.116		0.072	
$\geq$200m	Leases Acquired	2,749	114.5	3,391	339.1
	Leases Explored	422	17.6	281	28.1
	Exploration Rate	0.154		0.083	

"Average" means per lease offering.

Table 2.2: Acquired and explored deep water leases by depth and policy regime.

	Mean	Std. Deviation	Minimum	Maximum
Leased	0.049	0.216	0.0	1
DWRRA Eligible	0.244	0.429	0	1
Spot Price - Oil	20.76	4.94	12.65	30.89
Proportional Output Gap	0.373	1.52	-3.38	3.09
Own: newly available	0.019	0.136	0	1
↪ expired	0.012	0.111	0	1
↪ explored	0.002	0.046	0	1
↪ qualified	0.001	0.025	0	1
Own: previously leased	0.066	0.248	0	1
↪ expired	0.038	0.192	0	1
↪ explored	0.009	0.093	0	1
↪ qualified	0.002	0.045	0	1
Neighbors: # leased	0.754	1.521	0	10
Neighbors: # explored	0.169	0.710	0	10
Neighbors: # qualified	0.044	0.306	0	7
Neighbors: # producing	0.024	0.238	0	6
Neighbors: Δ # leased	0.112	0.687	-7	8
Neighbors: Δ # explored	0.010	0.110	0	4
Neighbors: Δ # qualified	0.005	0.073	0	3
Neighbors: Δ # producing	0.002	0.052	0	3
N	124,564			

Table 2.3: Acquisition – descriptive statistics.

Dependent Variable: Leased – block i sold in period t auction.

	(1)	(2)	(3)
DWRRA Eligible	0.074***	0.249***	0.246***
	(27.04)	(25.57)	(25.51)
Spot Price - Oil	-0.0004***	0.0001	0.0001
	(-3.88)	(0.56)	(0.42)
Proportional Output Gap	-0.005***	-0.004***	-0.004***
	(-12.54)	(-6.00)	(-6.01)
Own: newly available	-0.01	-0.003	-0.004
	(-1.94)	(-0.52)	(-0.79)
↪ expired	0.081***	0.064***	0.056***
	(4.95)	(4.32)	(4.08)
↪ explored	-0.025***	-0.029***	-0.027***
	(-4.45)	(-5.77)	(-5.32)
↪ qualified	-0.009	-0.01	-0.008
	(-0.56)	(-0.69)	(-0.53)
Own: previously leased	0.067***	0.07***	0.07***
	(10.97)	(10.97)	(11.17)
↪ expired	-0.007*	-0.004	-0.001
	(-1.97)	(-1.03)	(-0.17)
↪ explored	0.004	0.001	-0.004
	(0.57)	(0.16)	(-0.61)
↪ qualified	0.035*	0.044*	0.041*
	(1.97)	(2.12)	(2.20)
Neighbors: # leased	0.008***	0.01***	0.009***
	(19.85)	(24.42)	(23.15)
Neighbors: # explored	-0.0002	-0.001	0.0004
	(-0.17)	(-0.82)	(0.35)
Neighbors: # qualified	0.006*	0.002	-0.002
	(2.01)	(0.53)	(-0.74)
Neighbors: # producing	-0.013***	-0.01**	-0.003
	(-4.15)	(-3.03)	(-1.11)
Neighbors: Δ # leased	0.008***	0.005***	0.005***
	(10.69)	(6.75)	(7.17)
Neighbors: Δ # explored	0.030***	0.026***	0.023***
	(8.19)	(7.35)	(6.61)
Neighbors: Δ # qualified	0.021***	0.021***	0.023***
	(3.52)	(3.68)	(4.20)
Neighbors: Δ # producing	-0.004	-0.008	-0.011
	(-0.47)	(-0.89)	(-1.28)
Polynomial time trend	No	Yes	No
Polynomial time trends (by depth)	No	No	Yes
N	124,564	124,564	124,564
Pseudo R^2	0.1320	0.1512	0.1548

Cluster-robust z statistics in parentheses (clustered on block).
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 2.4: Acquisition – logit model marginal effect estimates.

	Mean	Std. Deviation	Minimum	Maximum
Winning bid (2009 $)	1,416,716	2,964,280	217	59,200,000
ln[Winning bid (2009 $)]	13.41	1.07	5.38	17.20
DWRRA Eligible	0.554	0.497	0	1
Spot Price - Oil	20.63	4.59	12.65	30.89
Lease water depth (1000s ft.)	4.604	2.435	0.578	11.159
(Lease water depth)^2	27.13	25.05	0.334	124.52
Own: newly available	0.092	0.289	0	1
$\hookrightarrow$ expired	0.078	0.268	0	1
$\hookrightarrow$ explored	0.009	0.093	0	1
$\hookrightarrow$ qualified	0.003	0.058	0	1
Own: previously leased	0.268	0.443	0	1
$\hookrightarrow$ expired	0.177	0.382	0	1
$\hookrightarrow$ explored	0.035	0.183	0	1
$\hookrightarrow$ qualified	0.011	0.104	0	1
Neighbors: # leased	2.058	2.116	0	9
Neighbors: # explored	0.571	1.258	0	10
Neighbors: # qualified	0.163	0.573	0	6
Neighbors: # producing	0.078	0.418	0	6
Neighbors: Δ # leased	0.447	1.181	-6	8
Neighbors: Δ # explored	0.050	0.248	0	4
Neighbors: Δ # qualified	0.025	0.177	0	3
Neighbors: Δ # producing	0.007	0.096	0	2
N		6,140		

Table 2.5: Bidding – descriptive statistics.

Dependent Variable: ln[winning bid (2009 $)].

	(1)	(2)	(3)
DWRRA Eligible	0.206***	0.657***	0.603***
	(7.50)	(12.07)	(11.05)
Spot Price - Oil	-0.007*	-0.009**	-0.006
	(-1.97)	(-2.80)	(-1.93)
Lease water depth	0.066**	0.088***	0.155***
	(2.72)	(3.69)	(4.63)
(Lease water depth)^2	-0.007***	-0.009***	-0.015***
	(-3.32)	(-4.26)	(-5.26)
Own: newly available	0.258*	0.248*	0.265*
	(2.38)	(2.36)	(2.56)
↪ expired	0.162	0.144	0.094
	(1.22)	(1.12)	(0.74)
↪ explored	-0.341	-0.383	-0.388
	(-1.43)	(-1.63)	(-1.70)
↪ qualified	0.105	0.099	0.152
	(0.29)	(0.28)	(0.45)
Own: previously leased	0.129**	0.226***	0.229***
	(2.95)	(5.14)	(5.26)
↪ expired	0.171*	0.200**	0.239***
	(2.53)	(3.03)	(3.60)
↪ explored	0.104	0.086	0.065
	(0.94)	(0.78)	(0.59)
↪ qualified	0.127	0.172	0.156
	(0.70)	(0.97)	(0.91)
Neighbors: # leased	0.033***	0.045***	0.045***
	(4.09)	(5.57)	(5.62)
Neighbors: # explored	-0.017	-0.006	0.002
	(-0.86)	(-0.30)	(0.10)
Neighbors: # qualified	0.097	0.054	0.020
	(1.86)	(1.06)	(0.39)
Neighbors: # producing	-0.148*	-0.145*	-0.080
	(-2.45)	(-2.48)	(-1.32)
Neighbors: Δ # leased	0.023	0.007	0.007
	(1.89)	(0.55)	(0.57)
Neighbors: Δ # explored	0.108*	0.091	0.067
	(2.10)	(1.76)	(1.32)
Neighbors: Δ # qualified	0.068	0.080	0.118
	(0.70)	(0.83)	(1.30)
Neighbors: Δ # producing	0.006	0.025	-0.047
	(0.04)	(0.18)	(-0.33)
Polynomial time trend	No	Yes	No
Polynomial time trends (by depth)	No	No	Yes
Reserve bid dummies	Yes	Yes	Yes
N	6,140	6,140	6,140
R^2	0.321	0.346	0.353

Cluster-robust t statistics in parentheses (clustered on lease).
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 2.6: Bidding – coefficient estimates (estimates for constant term unreported).

	Mean	Std. Deviation	Minimum	Maximum
Drilled	0.0013	0.036	0	1
DWRRA Eligible	0.585	0.493	0	1
DWRRA Eligible × Spot Price	20.21	22.57	0	134.60
Lease water depth (1000s ft.)	4.99	2.27	0.578	11.159
(Lease water depth)^2	30.09	24.21	0.334	124.52
First year of lease	0.136	0.343	0	1
Last year of lease	0.113	0.317	0	1
Spot Price - Oil	28.98	16.81	11.24	134.60
Spot Price - Oil (at auction)	20.59	4.45	12.65	30.89
Own: newly available	0.078	0.2668	0	1
$\hookrightarrow$ expired	0.065	0.246	0	1
$\hookrightarrow$ explored	0.007	0.080	0	1
$\hookrightarrow$ qualified	0.003	0.052	0	1
Own: previously leased	0.231	0.422	0	1
$\hookrightarrow$ expired	0.138	0.345	0	1
$\hookrightarrow$ explored	0.024	0.154	0	1
$\hookrightarrow$ qualified	0.009	0.093	0	1
Neighbors: # leased	5.25	1.927	0	10
Neighbors: # explored	0.693	1.307	0	10
Neighbors: # qualified	0.316	0.842	0	8
Neighbors: # producing	0.132	0.584	0	8
Neighbors: Δ # leased	0.861	1.909	-8	8
Neighbors: Δ # explored	0.268	0.639	0	6
Neighbors: Δ # qualified	0.127	0.460	0	6
Neighbors: Δ # producing	0.073	0.392	0	7
Neighbors: # leased (DWRRA)	2.847	2.631	0	9
Neighbors: # explored (DWRRA)	0.175	0.515	0	6
Neighbors: # qualified (DWRRA)	0.052	0.267	0	4
Neighbors: # producing (DWRRA)	0.016	0.149	0	3
Neighbors: Δ # leased (DWRRA)	0.667	1.607	-8	8
Neighbors: Δ # explored (DWRRA)	0.118	0.431	-3	5
Neighbors: Δ # qualified (DWRRA)	0.037	0.234	-2	4
Neighbors: Δ # producing (DWRRA)	0.015	0.147	-1	3
N	538,003			

Table 2.7: Exploration – descriptive statistics.

Dependent Variable: Drilled – lease i drilled in month t.

	(1)	(2)	(3)
DWRRA Eligible	-0.0009**	-0.0004	-0.0002
	(-3.34)	(-1.16)	(-0.63)
DWRRA Eligible × Spot Price	0.00001	0.000006	0.000001
	(1.40)	(0.70)	(0.05)
Lease water depth	-0.0003***	-0.0003**	-0.0004***
	(-3.83)	(-3.10)	(-3.57)
(Lease water depth)^2	0.00002*	0.00002	0.00002*
	(2.05)	(1.67)	(2.24)
First year of lease	0.00009	0.0003	0.0003
	(0.53)	(1.72)	(1.73)
Last year of lease	0.0019***	0.0016***	0.0016***
	(7.68)	(6.82)	(6.78)
Spot Price - Oil	-0.00002	-0.00001	-0.00001
	(-1.25)	(-1.01)	(-0.96)
Spot Price - Oil (at auction)	0.00005***	0.00004**	0.00004**
	(3.55)	(2.67)	(2.65)
Own: newly available	0.00003	0.00005	-0.00002
	(0.06)	(0.11)	(-0.05)
↪ expired	0.0008	0.0007	0.0008
	(1.01)	(0.92)	(0.99)
↪ explored	-0.0004	-0.0007*	-0.0007*
	(-1.02)	(-2.15)	(-2.00)
↪ qualified	-0.0003	-0.0001	-0.0002
	(-0.44)	(-0.12)	(-0.25)
Own: previously leased	0.0002	0.0002	0.0002
	(0.69)	(0.81)	(1.01)
↪ expired	0.0008**	0.0008*	0.0007*
	(2.41)	(2.27)	(2.16)
↪ explored	0.0005	0.0007*	0.0007
	(1.31)	(1.64)	(1.59)
↪ qualified	-0.0005	-0.0006	-0.0006
	(-1.36)	(-1.96)	(-1.87)
Calendar Year Fixed Effects	Yes	Yes	Yes
N	538,003	538,003	538,003
Pseudo R^2	0.069	0.083	0.084

Cluster robust z statistics in parentheses (clustered on lease).
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 2.8: Exploration – logit model marginal effect estimates for characteristics of individual lease-month.

Dependent Variable: Drilled – lease i drilled in month t.

	(1)	(2)	(3)
Neighbors: # leased		0.0001***	0.0002***
		(3.91)	(4.10)
Neighbors: # explored		-8.15e-07	-7.15e-06
		(-0.01)	(-0.09)
Neighbors: # qualified		0.0003*	0.0002
		(2.48)	(1.79)
Neighbors: # producing		-0.0001	-0.0001
		(-1.17)	(-0.98)
Neighbors: Δ # leased		0.0001***	0.0002***
		(3.99)	(3.99)
Neighbors: Δ # explored		0.0003**	0.0003***
		(2.99)	(3.27)
Neighbors: Δ # qualified		-0.00001	-0.00006
		(-0.12)	(-0.40)
Neighbors: Δ # producing		-0.0003	-0.0003
		(-1.94)	(-1.87)
Neighbors: # leased (DWRRA)			-0.00006
			(-1.21)
Neighbors: # explored (DWRRA)			0.0001
			(0.54)
Neighbors: # qualified (DWRRA)			0.00009
			(0.27)
Neighbors: # producing (DWRRA)			-0.0182***
			(-23.59)
Neighbors: Δ # leased (DWRRA)			-0.00005
			(-0.92)
Neighbors: Δ # explored (DWRRA)			-0.0002
			(-1.25)
Neighbors: Δ # qualified (DWRRA)			0.0002
			(0.57)
Neighbors: Δ # producing (DWRRA)			0.0182
			(25.89)
Calendar Year Fixed Effects	Yes	Yes	Yes
N	538,003	538,003	538,003
Pseudo R^2	0.069	0.083	0.084

Cluster robust z statistics in parentheses (clustered on lease).
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 2.9: Exploration, continued – logit model marginal effect estimates for quantities of neighboring blocks/leases in different states of development.

CHAPTER III

Estimates of the Value of Information Externalities in Oil and Gas Exploration

3.1 Introduction

This research quantifies the implied value of information spillovers in oil and natural gas exploration via an event study design. I examine cumulative unpredicted daily stock returns for firms owning leases adjacent to a lease where a hydrocarbon discovery occurs, during the trading days immediately preceding and following that discovery. In instances where the firms owning the discovery lease and the "neighboring" lease are different companies, I interpret the accumulated stock returns of the neighbor lease-owning firm as the value of new information. Combining leasing data from the Outer Continental Shelf (OCS) of the U.S. Gulf of Mexico and security returns data from North American stock exchanges, I find that 25 trading days after a discovery, firms that own leases adjacent to the discovery lease (but not the discovery lease, itself) realize an average abnormal return that translates to $315 million in market capitalization.

Exploratory drilling by the discovery lease owner generates a positive information externality for the neighbor leaseholders (assuming that owners of the discovery and neighbor leases are not coordinating their actions). Despite the fact that exploration produces a *pecuniary* externality – because the welfare effect on the neighboring firm is transmitted through the (stock) price – this finding still carries efficiency implications. Given that the estimated change in neighbor firm value is large relative to exploratory drilling costs,[1] these results suggest that the amount of exploration is below the welfare-maximizing level as prospective explorers do not take into account the high value of information that their activity could generate for their neighbors.

Information spillovers are an important component of hydrocarbon investment, if for no reason other than to rationalize the observed leasing behavior of oil and natural gas producers. This is because for the great majority of leases, particularly in deep water, no drilling is ever undertaken by the leaseholder. Setting aside the influence of technological and price changes, rational firms must have either believed at the time of sale that they would earn positive returns from these undrilled leases and then subsequent information caused them to revise these beliefs downward, or they valued the option to drill and held out for the prospect that subsequent information would place that option "in the money." Note that these spillovers are made possible by a combination of similar geology among geographically proximate leases and relatively small geographic lease size.

This paper contributes to the existing economic literature by assigning an average value to the information externality realized by the owners of neighboring leases following an oil discovery, which carries implications for the efficiency of the prevailing level of exploration. Previous economic research, however, has appreciated the existence and importance of information spillover in oil exploration for several decades, though without attempting to attach a value to them. Rather, past work has theorized the existence of these externalities and also empirically tested for their effects.

[1] The daily rental rate or "day rate" charged for the use of drilling crafts called "semisubmersibles" and "drillships" is the primary component of the costs of drilling an offshore well. During the period 1996-2008, the highest day rates were \$503,000 and \$650,000 for semisubmersibles and drillships, respectively (source: ODS-Petrodata). For the 1,582 exploratory wells drilled in the deep water of the Gulf of Mexico for the same period, the 90th percentile for days to drill the well is 98 days. Therefore, a very rough estimate of the cost of drilling a well is $98 \times \$650,000 = \$63,700,000$.

Some of the earlier studies to analyze information externalities in the context of oil exploration include Gilbert (1981), Miller (1973), Peterson (1975), Stiglitz (1975), and Leitzinger and Stiglitz (1984). Hendricks and Kovenock (1989) solve a dynamic game theoretic model between two rival firms holding adjacent leases. They find that both overinvestment and underinvestment are possible outcomes due to the presence of private information. Finally, Hendricks and Porter (1996) show empirically that information spillovers matter for subsequent investment. Using drilling data from the Gulf of Mexico, they find that while winning bids are a strong predicter or exploration shortly after a lease is sold, as time goes on, nearby drilling outcomes become a stronger predictor, suggesting the importance of information spillovers.

The remainder of the paper proceeds as follows: in section 2, I provide background on offshore oil and gas leasing and exploration. In section 3, I describe the data used and how I compiled it in order to conduct the analysis. I discuss the computation of abnormal returns in section 4. In section 5, I present and interpret the results of the event study analysis. Section 6 concludes.

3.2 U.S. Federal Offshore Oil and Gas Leasing

The Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) within the U.S. Department of Interior leases subsea tracts on the OCS to individual private firms or consortia of private firms.[2] These tracts (called "blocks" when unleased and "leases" when leased) are underwater parcels of land that usually measure three miles by three miles, covering an area of nine square-miles or 5,760 acres. Individual blocks are leased in individual first-price sealed bid auctions. Generally speaking, a single "lease offering," which constitutes thousands of simultaneous first-price sealed bid auctions, is held one time per calendar year per "planning area" for all blocks in the planning area that are not leased at the time of the lease offer-

[2]BOEMRE succeeds the Mineral Management Service (MMS).

ing.[3] Although consortia can bid for and own leases, BOEMRE tries to encourage competitiveness by limiting which consortia can be formed by prospective bidders. Specifically, the largest firms in the industry cannot legally submit joint bids.[4]

Subject to BOEMRE's determination that its bid reflects "fair market value," the prospective leaseholder that submits the highest bid then receives exclusive rights to explore and develop the lease for a term of five years (200-399m), eight years (400-799m), or ten years ($\geq$ 800m) depending on the block's predetermined depth category (in parentheses). If the leaseholder does not begin production of hydrocarbons during this term, then the lease is returned to the government to be made available in subsequent auctions.[5] Although, any activity which BOEMRE classifies as "operations," which includes drilling, can extend the lease beyond its primary term (Mineral Management Service 2001, page 50). During the period prior to production, the leaseholder pays an annual rental fee per lease acre which is due on the anniversary of the lease becoming effective. Figure 2.3 shows the annual rental fee for the various depth groups and for different years of sale – e.g. for a 5,760 acre lease sold in 1996 in greater than 800m of water, the total rental was \$43,200 per year or \$432,000 (in nominal terms) over the lifetime of the lease. The leaseholder can avoid these payments by relinquishing the lease, i.e. ending the lease term early by surrendering all rights to the acquired block. BOEMRE then re-offers the block for sale at the next lease offering.

Following the drilling of an exploratory well, the leaseholder is required to submit technical data gathered during the drilling process to BOEMRE (30 CFR 250.116).

[3]For administrative purposes, BOEMRE divides the Gulf of Mexico under U.S. jurisdiction into three so-called planning areas: the Western Gulf of Mexico (WGM), the Central Gulf of Mexico (CGM), and the Eastern Gulf of Mexico (EGM).

[4]As the level of concentration within upstream oil production has varied over time, so too has BOEMRE's "List of Restricted Joint Bidders." The membership on the list covering the period from November 1, 2003 through April 30, 2004, however, constitutes a useful snapshot: Exxon Mobil, Shell, BP, TOTAL, Chevron Texaco, and Conoco Phillips.

[5]Leases with eight-year terms are canceled if an exploratory well is not drilled within the first five years (Mineral Management Service 2001, page 50).

Upon review of these data, BOEMRE determines whether the well is "qualifying," i.e. whether the well (and by extension, the lease) is "capable of production in paying quantities." Once a lease is deemed producible, BOEMRE assigns it to a "field."[6] Whereas the lease is the administrative unit within the OCS of the Gulf of Mexico, the field is the geologic unit (and can be comprised of more than one lease). If and only if the leaseholder commences hydrocarbon production on the lease following successful exploration is the lease renewed indefinitely. In this case, BOEMRE waives rental fees and begins royalty collection. For any leases in depths of less than 400m sold prior to 2007, the royalty rate applied to production in the absence of any policy-induced adjustments is 16.67%; the analogous rate for leases in water more than 400m deep is 12.5%. Finally, once the lease has reached the end of its productive life, it is decommissioned and the block is returned to BOEMRE.

3.3 Data

In this paper, I examine abnormal returns within an event window around the discovery date for firms that own neighboring leases to the lease on which a hydrocarbon discovery was made. An increase in abnormal returns during this period is indicative of the value of new information about the company's own lease generated by the "good news" of the discovery on the neighboring lease. In order to measure neighbors' abnormal returns, I combine leasing data collected by BOEMRE with security price, return, and volume data collected by the Center for Research in Security Prices (CRSP). While this describes my general approach, I provide much more detail below.

[6]BOEMRE defines a field as "an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both" (61 FR 12027).

3.3.1 Discoveries

In constructing the analytic data set, I begin with a list of discoveries maintained by BOEMRE called "Deepwater natural gas and oil discoveries and fields," which is comprised of all leases in U.S. Gulf of Mexico waters greater than 1,000 feet deep on which a hydrocarbon discovery occurred, starting in 1975.[7] The list only includes discoveries that BOEMRE has classified as "qualifying"[8] – meaning that BOEMRE has reviewed technical data from the exploratory well and deemed the well (and by the extension, the lease) as economically viable (30 CFR 250.116). Thus, while this list is convenient in that it compiles various discoveries in a single location, it has the added advantage that it features only those announced discoveries that have been corroborated by a government review (although it should be noted that whether or not a lease qualifies would not be known at the time of the discovery). BOEMRE assigns any qualifying lease to a new or existing field, which represents the geological structure existing under one or more leases. After eliminating duplicate observations representing additional operators (the firms that perform the actual drilling) on the same lease assigned to a given field, the list contains 440 lease-fields each representing an instance where an operator drilled an exploratory well on the lease and BOEMRE subsequently classified the lease as qualifying (i.e. the operator discovered a reservoir capable of producing in "paying" quantities) and assigned it to a field.[9]

A potential shortcoming of these data is that the listed discovery date – the date on which the firm reported the discovery to BOEMRE[10] – takes the same value for

[7]BOEMRE makes this list available at the following location (which I most recently accessed on 3/19/2011): http://www.gomr.boemre.gov/homepg/offshore/deepwatr/deeptbl2.html.

[8]Gerald Crawford, BOEMRE, personal communication, 12/21/2010.

[9]The unit of observation is the "lease-field" rather than simply the lease because although there are 440 observations, there are only 431 unique leases in these data. This is due to the fact that nine leases are assigned to respective fields following exploration, and then later explored again and assigned to a new field different from the first one. Also, the original data contained 453 lease-fields, but 13 were dropped because they are in the Eastern Gulf of Mexico region planning area, for which I have not constructed geographic data necessary for the analysis.

[10]Gerald Crawford, BOEMRE, personal communication, 12/21/2010.

all leases that are assigned to the same field. Therefore, I interpret this variable as the date when the field, rather than the lease, was discovered. The challenge is then to determine which lease (of the up to 14 leases) assigned to the field actually established the field, i.e. on which lease did an operator make the initial discovery? Using the chronological order in which leases are assigned to a field along with a field discovery indicator in the leasing data (described in the next section) that flags leases where a discovery occurs, I identify a single lease for each field where the field was actually discovered. Given that the 440 lease-fields represent 210 unique fields, the final discovery data set has 210 observations. I will ignore the 230 leases that do not establish any field (they are assigned to their respective field subsequent to another lease which actually discovered that field) primarily because it is unclear what date is appropriate for the "discovery" on those particular leases and secondarily because the most valuable information will arguably be generated by the discovery of the initial field rather than discoveries of extensions to that field.

3.3.2 Discovery Leases and Neighbor Leases

The 210 field discoveries discussed above constitute the set of events for the event study. The area and block variables in these data provide the geographic location where the discovery was made. I make this more precise by using GIS data. By employing publicly-available BOEMRE data (coordinates in latitude and longitude for each block in the U.S. Gulf of Mexico), for any block i, I can generate its set of neighbor blocks.[11] According to my own criteria, some lease j is classified as a neighbor of lease i if j's centroid (geographic center point) is within five miles of i's centroid, which for a standard 3-mile square blocks results in exactly eight adjacent blocks in the set of neighbors (see Figure 3.1 for a graphical representation of a typical grouping of 25 blocks in the Gulf of Mexico). Therefore, for most discoveries, there

[11] These data, called "Blocks," are available in ASCII format by following link "8311" at http://www.gomr.boemre.gov/homepg/pubinfo/repcat/arcinfo/index.html.

will be up to eight leases on which information spillover might be captured. Of course, to the extent that this can be observed at all, it must at least be the case that the neighbor block is leased (which will not necessarily be the case).

Using publicly-available BOEMRE lease data, I match all leases ever associated with a given neighbor block and then only keep those that are coincident with the discovery (recall that a single block can be leased multiple times, each time receiving a new lease number).[12] Having mapped lease numbers to leased neighbor blocks (analogous information for the discovery lease is contained with the discoveries data already), I then access lease ownership spell data that BOEMRE makes public.[13] Due to the active secondary market in leases, determining which firms own a lease during the lease period is more challenging than checking which firm or consortium of firms submitted the accepted winning bid for the lease. With the correct lease number now associated with each lease (both discovery and neighbors), I then merge all ownership spells ever associated with that lease keeping only the unique spell for which the discovery date is contained within the interval defined by the spell's start and end dates. Importantly, the ownership spell data lists each firm that owns the lease during the period that defines the spell and also its respective percent interest in the lease during that spell. Each firm is identified by a numeric code assigned by BOEMRE, which I simply call "company." In the final analytic discovery lease owner dataset, there are 310 "firm-discoveries" representing publicly-traded firms owning a lease at the time of discovery. In the final analytic neighbor lease owner dataset, there are 827 "firm-neighbors" representing publicly-traded firms owning a lease that neighbors a lease where and when a discovery is made.

[12] These data are available in ASCII format by following link "LEASE DATA" at http://www.gomr.boemre.gov/homepg/pubinfo/freeasci/leasing/freeleas.html.

[13] These data are available in ASCII format by following link "LEASE OWNER" at http://www.gomr.boemre.gov/homepg/pubinfo/freeasci/leasing/freeleas.html.

3.3.3 Firms and Securities

In order to compute the abnormal returns for these lease owners, it is necessary to gather data on their equity returns. Such data are maintained by CRSP. Not surprisingly, however, the CRSP data do not include the BOEMRE "company" identifier and nor do the BOEMRE data include "permno," the unique "permanent security identification" number in the CRSP data. Therefore, in order to match firms with their stock returns, I manually construct "company"-permno correspondences, of which there can be several for a given value of "company." To be precise, I do not directly create the "company"-permno observations, rather for each "company" value, I match appropriate values of "gvkey," the "global company key" or unique company identifier for each firm in COMPUSTAT. I accomplish this task by making use of firm name and address information in the BOEMRE data and then conducting string searches on the company name variable in COMPUSTAT. Next, I supplement any findings by gleaning additional information from company web sites, articles from periodicals archived online, and online firm databases geared to investors,[14] among other sources. One complicating factor in building the "company"-gvkey crosswalk is the increased consolidation in the upstream oil and natural gas industries beginning in the 1990s. In cases where a firm's stock is de-listed following a merger or acquisition, I end all correspondences between the "company" value and the de-listed firm's gvkey value on the day prior to the "date of the de-listing payment" in the CRSP database. Following that date, that "company" value will then correspond to the acquiring firm's gvkey value.

Before proceeding, I discuss why I perform the seemingly intermediate step of matching "company" to gvkey values, instead of assigning permno values directly. Note that unlike the unique *firm* identifier gvkey in COMPUSTAT, permno is the

[14]For example, the "Company Insight Center" from bloomberg.com and *Business Week*, http://investing.businessweek.com/research/company/overview/overview.asp.

unique *security* identifier in CRSP (although for companies that only ever have a single issue of common stock, the permno value is unique to the firm). Furthermore, along with CRSP and Compustat databases, Wharton Research Data Services (WRDS) also makes the CRSP/COMPUSTAT Merged (CCM) Database available which associates the unique identifiers between each database. Therefore I focus on determining firm-to-firm matches between the BOEMRE and COMPUSTAT data and then rely on well-established correspondences between firms in COMPUSTAT and securities in CRSP in order ultimately to establish mappings between firms in the BOEMRE data and securities in CRSP. Once I have generated all necessary "company"-to-gvkey mappings, I then merge these data to the CCM database. Each line of the final crosswalk represents a unique "company" value and includes arrays of permno values and dates where the latter define intervals over which the former are correct or not. Applied to the BOEMRE data, this crosswalk allows the correct security data to be matched to any firm on any given date. Using the unique list of permno values in the crosswalk, I am then able to extract the CRSP "Daily Stock" data, which includes information for equities that trade on North American exchanges only.[15]

These securities correspond to the 84 unique firms present in the data, which can be further divided into 116 unique "firm-spells" (referred to simply as "spells" in the remainder of the paper). For example, although BP is a single firm that operates during the entire sample period, it has five distinct spells in these data, each representing the period following a major merger or acquisitions.[16] I partition firms into spells so that the coefficients of the normal returns model can vary flexibly with the make-up of the firm.

[15]For example, Nippon Oil Exploration USA Limited is a subsidiary of Nippon Oil Corporation, which trades on the Tokyo Stock Exchange. Therefore, despite being publicly-traded, a company's equity returns can be missing from the data, though this is not common in the data.

[16]Besides M&A, the de-listing and initial public offering concludes and initiates a spell, respectively.

3.3.4 Commodity Prices

The daily one-month oil futures price, alternately known as the daily "nearby delivery month" price (which functions as the spot price) for oil is used in estimating the normal returns model in the following section. It is collected from the New York Mercantile Exchange by the U.S. Energy Information Administration (EIA). These data are also downloadable.[17]

3.4 Event Study

In order to estimate the value of information from a given discovery – for both the owners of the lease where the discovery occurs and for the owners of neighboring leases – I must first model the equity returns of any publicly-traded firm ever owning a lease in the data. I accomplish this by estimating a normal returns model from the abnormal returns will be derived (for a survey of the event study methodology, see MacKinlay (1997). Obviously, the 210 unique discoveries in the data comprise the set of events, and these can be indexed by $d = 1, 2, \ldots, 210$. Furthermore, let t^d represent the discovery date in calendar time for the d-th discovery (i.e. t^d is a realization of the integer-valued variable t). The event window for the d-th discovery is the set of 31 trading days

$$\mathbf{T}_d = \{t : t \in [t^d - 5, t^d + 25]\}$$

which constitutes the period of time over which I will examine the response, if any, of returns on the given security to the discovery.

These securities correspond to the 84 unique firms mentioned earlier, which can be further divided into 116 unique spells representing different incarnations of the firm (e.g. before-and-after a merger). Indexing the spells by i, I define $\mathbf{T}^i$ as the set

[17]From website http://www.eia.gov/dnav/pet/pet_pri_fut_s1_d.htm.

of trading days during which shares of the firm represented by spell i are actively traded.[18] These firms are included in the data because each is associated with at least one discovery, as either the owner of the lease where the discovery occurred or as the owner of a neighbor to that lease where the discovery occurred. Let $\mathbf{D}^i$ be the set of discoveries to which spell i is associated in this way, where

$$\mathbf{T}_{\mathbf{D}^i} = \bigcup_{d \in \mathbf{D}^i} \mathbf{T}_d$$

is the union of event windows for these discoveries.

The following normal returns model is estimated via OLS, separately for each spell i:

$$R_{it} = \alpha^i + \beta^i_o R_{ot} + \beta^i_m R_{mt} + \varepsilon_{it}, \tag{3.1}$$

where the estimation sample is $\forall t \in \mathbf{T}^i \backslash \mathbf{T}_{\mathbf{D}^i}$, and R_{it} is the one-day return on the firm's equity, R_{ot} is the one-day return on a barrel of oil, and R_{mt} is the one-day return on the Standard & Poors 500 Composite Index. Note that I omit returns on trading days within all event windows because arguably these returns are affected by the event and their inclusion in the estimation of the normal model would therefore undermine the estimation of the abnormal returns. The abnormal return is defined as:

$$\begin{aligned} AR_{it} &\equiv R_{it} - \hat{R}_{it} \\ &\equiv R_{it} - (\hat{\alpha}^i + \hat{\beta}^i_o R_{ot} + \hat{\beta}^m_R R_{mt}), \end{aligned}$$

i.e. within the event window, it is the out-of-sample residual return (the component of the return not predicted by the model).

[18] Specifically, on North American stock exchanges during 01/02/1975 through 12/31/2010.

Figures 3.2 and 3.3 plot mean abnormal returns (in terms of market capitalization) within event window day t, for all event days $t \in [-5, 25]$ for discovery lease owners and neighbor lease owners, respectively. Although these graphs suggest that abnormal returns converted to firm value are positive following a discovery, one should exercise caution in interpreting them. The plots are not made using all of the data, specifically, they exclude firm-days that appear in two different event windows simultaneously (for example, if a firm owned two different leases each of which had a discovery within 31 trading days of each other). The reason for this exclusion is that it is not clear to which value of t within the event window to assign such firm-days. Finally, the trends marked "% ownership adjusted" are divided by the percentage of the lease held by the firm (expressed as a proportion). So, for example, if a firm owns 50% of a lease, then it's abnormal return is weighted by 2. An analogous weighting scheme, applied to RHS variables, is adopted for the regressions in the next section.

3.5 Empirical Analysis

3.5.1 Regression Variables

Having estimated the daily abnormal returns, I can now examine how this measure changes within the event window around the discovery date. Before proceeding, I define the following dependent variable, which will allow the coefficient estimates to be expressed in terms of firm value:

$$\widetilde{AR}_{it} = (AR_{it} \times mkt\ cap_{it}),$$

where $mkt\ cap_{it}$ is firm i's market capitalization on trading day t – the product of the share's closing price and the number of publicly-held shares, both on trading day t. Given the heterogeneity in firm size in the data, weighting abnormal returns by market capitalization makes for easier interpretation of the sample statistics. With regard to the RHS variables, the building blocks for these are the following sets of dummy variables:

$$d_{it} = \begin{cases} 1 & \text{if } t \text{ trading days have passed since (if } t > 0) \text{ or will pass prior to} \\ & \text{(if } t < 0) \text{ a discovery on a lease owned by firm } i; \\ 0 & \text{otherwise.} \end{cases}$$

and

$$n_{it} = \begin{cases} 1 & \text{if } t \text{ trading days have passed since (if } t > 0) \text{ or will pass prior to} \\ & \text{(if } t < 0) \text{ a discovery on a lease to which a lease owned by firm } i \text{ is a} \\ & \text{neighbor;} \\ 0 & \text{otherwise.} \end{cases}$$

For example, if firm i owns a lease where a discovery occurs on whatever calendar date, then that date is indexed at $t = 0$ for that discovery's event window and $d_{i0} = 1$ for that firm. Likewise, s trading days after the discovery date, $d_{is} = 1$. For some firm j (which could be the same firm as i in the current example) that owns a lease that neighbors the lease where the discovery occurred, $n_{j0} = 1$ on $t = 0$ and $n_{js} = 1$ s trading days after the discovery.

Note that it is very often the case in the U.S. Gulf of Mexico that an individual lease will be jointly-owned by several firms simultaneously. In order to account for this in the analysis, I introduce the following variables, which are defined for all t values for which d_{it} and n_{it} are defined:

$$\begin{aligned} D_{it} &= d_{it} \times d\_pct_{it} \\ N_{it} &= n_{it} \times n\_pct_{it}, \end{aligned}$$

where d_pct_{it} is firm i's percent ownership interest in the lease where the discovery occurs and n_pct_{it} is the *sum* of firm i's percent ownership interests in the leases in the neighbor set of the lease where the discovery occurs (in all cases, percent ownership is expressed as a proportion).[19]

Finally, in one specification, I interact the percent ownership-weighted event day dummies with a variable measuring the distance in miles from the (centroid of the) discovery lease to the (centroid of the) nearest lease that produced positive quantities of oil or natural gas during the six months prior to the date of discovery. If one imagines a lease where a discovery occurs on date t, this distance variable is represented by d_dist_{it} if firm i owns the lease and n_dist_{it} if firm i owns a neighboring lease.[20]

3.5.2 Regression Models: Baseline Specifications

I estimate two baseline specifications. The first of these is

$$\widetilde{AR}_{it} = \alpha + \sum_{t=-5}^{25} \beta_t D_{it} + \sum_{t=-5}^{25} \gamma_t N_{it} + \epsilon_{it}. \tag{3.2}$$

The individual day t coefficient (when summed with α) is the mean abnormal return on day t for either discovery lease owners or neighbors. In the context of summing up these coefficients, the individual day t coefficient constitutes the marginal effect of event day t on the cumulative abnormal return. So, in this simplest specification, the γ's will represent the value of the information spillover. If the information externality does exist (and is perceived by the market to be valuable), then we expect that the γ's would be positive when summed after $t = 0$.

Of course, a weakness of this specification is the fact that it cannot distinguish between neighbor firms that own the discovery lease and those that do not. Given the

[19] Returning to the lower panel of Figure 3.1, imagine that a discovery occurs on lease M. Furthermore, assume that the same firm owns 50% of lease H and 25% of lease N, both of which are in M's neighbor set. In this case, $n\_pct_{it} = 0.25 + 0.5 = 0.75$. This summation also applies *across* discoveries in instances where a firm owns leases neighboring two different discoveries having the same discovery date.

[20] If two different discoveries share the same date, and firm i owns leases neighboring both, then n_dist_{it} will be the average distance for the two discovery leases.

paper's interest in information that cannot be internalized by the firm undertaking the investment, I would like to be able to separate these two types of neighbors, which motivates the second baseline specification:

$$\widetilde{AR}_{it} = \alpha + \sum_{t=-5}^{25} \beta_t D_{it} + \sum_{t=-5}^{25} \gamma_t N_{it} + \sum_{t=-5}^{25} \delta_t D_{it} N_{it} + \epsilon_{it}. \tag{3.3}$$

In (3.3), the summed γ's represent the event day effect on the cumulative abnormal returns of firms that simultaneously own lease(s) that neighbor a lease where a discovery occurs and do not own the actual lease where the discovery was made. It is these firms that will capture the spillover, if one exists.

3.5.3 Regression Models: Extensions

The extensions to the baseline models discussed below allow for the estimation of more flexible effects. Specifically, the value of the spillover is permitted to vary with the "intensity" of other variables that arguably affect its value – distance from existing production and oil price. A variation of (3.3), the first extension adds interactions with a variable measuring the distance of the discovery lease from existing production at the time of the discovery:

$$\begin{aligned}
\widetilde{AR}_{it} \quad = \quad & \alpha + \sum_{t=-5}^{25} \beta_t D_{it} + \sum_{t=-5}^{25} \gamma_t N_{it} + \sum_{t=-5}^{25} \delta_t D_{it} N_{it} \\
& + \sum_{t=-5}^{25} \zeta_t (d_dist_{it} \cdot D_{it}) + \sum_{t=-5}^{25} \eta_t (n_dist_{it} \cdot N_{it}) + \sum_{t=-5}^{25} \theta_t (d_dist_{it} \cdot D_{it} N_{it}) \\
& + \epsilon_{it}.
\end{aligned} \tag{3.4}$$

In this way, the marginal effect of being in day t of the event window is permitted to vary (additively) with distance from current (as of the discovery) production. The logic for the inclusion of these additional terms is as follows: the abnormal return represents the return not predicted by the market, and we might expect that there is greater uncertainty regarding drilling in areas further away from existing production, i.e. in less established areas of the Gulf of Mexico. This specification will pick up any such effect.

The final two extensions incorporate the oil price. The first of these is another variation of (3.3):

$$\begin{aligned}\widetilde{AR}_{it} &= \alpha + \sum_{t=-5}^{25} \beta_t D_{it} + \sum_{t=-5}^{25} \gamma_t N_{it} + \sum_{t=-5}^{25} \delta_t D_{it} N_{it} \\ &\quad + \sum_{t=-5}^{25} \iota_t (p_0 \cdot D_{it}) + \sum_{t=-5}^{25} \kappa_t (p_0 \cdot N_{it}) + \sum_{t=-5}^{25} \lambda_t (p_0 \cdot D_{it} N_{it}) + \epsilon_{it} \quad (3.5)\end{aligned}$$

where p_0 is the real price of oil on the date of the discovery (or the most recent day on which oil is traded, if the discovery occurs on a weekend or holiday). The effect of the trading day on the abnormal return is now permitted to vary with the oil price at the time of the discovery. Lastly, the specification

$$\widetilde{AR}_{it} = \alpha + \sum_{t=-5}^{25} \iota_t (p_0 \cdot D_{it}) + \sum_{t=-5}^{25} \kappa_t (p_0 \cdot N_{it}) + \sum_{t=-5}^{25} \lambda_t (p_0 \cdot D_{it} N_{it}) + \epsilon_{it} \quad (3.6)$$

drops the estimated mean effects in (3.5) (the β's, γ's, and δ's), taking into account directly the effect of oil price on the discovery date in estimating the coefficients.

3.5.4 Results and Discussion

In presenting the results, I emphasize the sums of estimated coefficients from the beginning of the event window forward, rather than the sum of coefficients for event days $t = 0$ and $t = 1$, for example (or for that matter, just the estimated coefficient for $t = 1$). I employ this strategy because although the theory of efficient markets holds that any new information should be capitalized in asset prices instantaneously upon its release, it is not clear in this context that investors can fully and immediately appreciate the value of a new hydrocarbon discovery in terms of present discounted value of future profits from the new reservoir on or even one day after the date of the discovery. In using the [-5,25] trading days event window, I allow for investors to first learn *of* then *about* each discovery. Then, summing over trading day coefficients, I get a measure of the cumulative abnormal return and an estimate of the market value of new information.

Before continuing, it is also worth detailing what is known regarding the channels by which information about discoveries is conveyed to the market. Although BOEMRE publishes the list of discoveries – "Deepwater natural gas and oil discoveries and fields" – on its website, the discovery date listed therein is not the date when information about the discovery was formally signalled to investors. From discussions with a BOEMRE official, I have learned that BOEMRE never formally announces discoveries, rather it simply updates "Deepwater natural gas and oil discoveries and fields" on a monthly basis.[21] The investor responses in terms of cumulative abnormal returns detected in the data, however, imply that the listed discovery date does coincide with the receipt of information by market participants (see, for example, Figures 3.7 and 3.8, where the graphed cumulative abnormal returns deviate from 0 beginning at $t = 0$). Market movements in the absence of formal announcements suggest that there exist informal mechanisms by which the information contained in the firm's revelation of the discovery to the government is still conveyed to the broader markets.

Individual coefficient estimates for baseline specifications (3.2) and (3.3) are presented in tables 3.1 and 3.2, respectively (note: although I present the results for specifications (3.4), (3.5), (3.6) graphically, I do not include analogous tables with individual coefficient estimates). For ease of interpretation and also to emphasize cumulative abnormal returns rather than abnormal returns, I graphically present summed regression coefficients along with their associated 95% confidence intervals

[21] Gerald Crawford, BOEMRE, personal communication, 9/1/2011.

in Figures 3.4 through 3.18. Each of these figures also includes a line at zero. Instances where the zero line falls within the confidence interval is equivalent to failing to reject the null hypothesis in a Wald test with the single linear restriction that $\sum_{s=-5}^{t} \beta_s = 0$ in the case of the baseline specification (3.2), for instance.

The summed coefficient estimates for (3.2) can be seen in the lower panels of Figures 3.4 and 3.5. In this case, the results suggest that firms owning the discovery receive a negative return while their neighbors experience a positive return (summed over the 25 trading days following the discovery at $t = 0$). As mentioned earlier though, a weakness of this specification is that it does not control for different effects for neighbors depending on whether they own the lease where the discovery occurs. Given that the fundamental issue is one of an externality that cannot be internalized by the discovery owner (which cannot control whether neighbors learn of its discovery), we want to make sure that we are estimating the effect for neighbors that do not own the discovery lease.

Specification (3.3) allows for this, and we proceed to it next. Focusing on Figure 3.8, we see that after 25 trading days, the sum of estimated coefficients (the γ's) is approximately \$315 million and is significantly different from 0. In this case, these neighbors do not own the lease where the discovery occurred – just some lease that is adjacent to that lease – so this represents the spillover in which our interest lies. Note that in the case of discovery owners, the cumulative abnormal return is roughly \$100 million 25 trading days after the discovery, though throughout most of the event window, the cumulative abnormal return is negative. In any event, the cumulative abnormal return is significantly different from 0 for only a short time early in the event window (see Figure (3.6)). Finally, for owners of neighbor leases that also own the discovery lease, the estimated cumulative abnormal return 25 days after the discovery is approximately negative \$400 million, which is statistically significant (see Figure (3.7)).

In the baseline specifications, the point estimates for the lease owner (whether they own neighbor leases or not) are somewhat counterintuitive: the discovery-owning firm paradoxically realizes a loss in equity value following its own discovery. For discovery lease owners, the estimated cumulative abnormal return is negative in the baseline specifications, while it is either generally positive or near 0 in the extensions. In all cases other than the simpler baseline specification, the cumulative abnormal return is not significantly different from 0 at the end of the event window. The paradox of negative returns for a discovery is also present for firms owning neighboring leases *and* the discovery lease. This result, along with positive point estimates for cumulative abnormal returns for neighbor lease owners that do not also own the discovery lease, is remarkably stable (at least with regard to the signs of the effects) from the richer baseline specification, (3.3), through the extensions. This fact suggests that the counterintuitive pattern in the results is roughly invariant to the model specification (at least for those models presented here).

As consistent as the narrative described above is in the results, it is difficult to rationalize. In effect, the estimates imply that gaining direct access to a new hydrocarbon reservoir is not as valuable as upwardly updated beliefs about gaining direct access to a new hydrocarbon reservoir.[22] Though the event window for this analysis is constructed to start five trading days before the discovery date and to end 25 trading days after the discovery date, this does not preclude meaningful unpredicted movements in the return on firms' equity from occurring outside of this interval, particularly for firms owning discovery leases. More to the point, perhaps investors have already built the value of the discovery into the equity price of eventual discovery lease owners by the time the firm informs the government of the discovery (trading day $t = 0$ in the analysis). Given both the daunting technical challenges and the

[22]While a neighbor's discovery of a new deposit will likely cause a lease-holding firm to be more optimistic regarding a potential discovery on its own lease, it certainly does not guarantee that a discovery will occur on its lease.

relative scarcity of the necessary drilling capital, hydrocarbon exploration in deep water is exceedingly expensive and therefore rare. Thus, when a leaseholder undertakes a drilling plan, it does so only after having done everything short of drilling to determine with as much certainty as possible what oil and natural gas are present on the lease. In this way, the decision to drill potentially conveys a great deal of information regarding the firm's future profits. If investors wait for confirmation of the discovery, however, to invest in firms that hold leases adjacent to the explored lease, then we would observe the counterintuitive results seen in this paper. Furthermore, in these data, only successful exploration is included. If investors are purchasing stock in exploring firms before the outcome of the exploration is known with certainty, then we would expect returns on equity to fall for these firms following unsuccessful exploration (as stockholders divested).

Of course, in this context it is not the value of a discovery that ultimately matters, but rather the value of the discovery *relative to the stock market's expectations about the value*. This implies that exploration need not be unsuccessful in order to observe the counterintuitive pattern in the data. These results could arise because investors are generally overoptimistic (or possess accurate expectations) regarding the value of new discoveries for firms that own the discovery lease, while simultaneously being overly pessimistic with respect to the value of new discoveries for firms owning neighboring leases. In this scenario, with the onset of exploratory drilling, investors update their beliefs about the firms' profitabilities and then subsequently update them again with the occurrence of the discovery. It is in this second round of updating, with the confirmation of the discovery, that firms can evaluate the accuracy of the initial beliefs that they established when mere exploration began. Information regarding the discovery that is not observed by the econometrician but available to investors (at the time of the discovery) would serve as the basis for their updated beliefs about firms' profitability. Initial over-optimism results in divestment in shares of discovery-lease-owning firms while initial over-pessimism results in investment in neighbor-lease-owning firms, consistent with the pattern in the data.

Finally, note that although the extensions to the baseline specifications generate point estimates for the cumulative abnormal return that are largely consistent with those produced by the baseline specifications, the estimated effects are not significantly different from 0. These results are presented in the lower panels of Figures 3.10 to 3.18. Given that all of the event day marginal effects include at least one interacted term (with distance or price), in order to present numeric results, I have to select specific values of distance and price at which to evaluate the marginal effect. For Figures 3.10 to 3.12, I used the median distance for both discovery leases and neighbor leases (19.4 and 16.4 miles, respectively). The distributions of the distance variable for the discovery and neighbor leases are presented as Figure 3.9. For Figures 3.13 to 3.18, I use the average (real) oil prices across discovery and neighbor leases at the time of the discovery: \$41.58 and \$43.97, respectively. The fact that the introduction of interacted terms in the baseline specifications does not produce statistically significant effects on the cumulative abnormal return suggests that the value of the information spillovers does not vary with distance from existing production or with the oil price at the time of the discovery.

3.6 Conclusion

In this paper, I have used securities data along with hydrocarbon leasing data to estimate the value of information spillovers from exploration. In my preferred specification, among firms owning neighbor leases, I separate those that also own the discovery leases from those that do not. For the latter group, I estimate that 25 trading days after the discovery, firm value increases by \$315 million, a large and statistically significant result. This finding is novel because it represents a first attempt at trying to measure that value of these information spillovers, though the literature has regarded these externalities as important for some time. Given the high estimated value of this information, there is reason to believe that the amount of drilling is inefficiently low (at least from the standpoint of direct costs of oil and natural gas exploration).

3.7 Appendix: Examining differences between Figures 3.2 and 3.4

A surprising result in the paper is the apparent disagreement between Figure 3.2 and the lower panel of Figure 3.4. Figure 3.2 graphs the sums of mean (within trading day across firms) abnormal returns from event day $s = -5$ through event day $s = t$ while the lower panel of Figure 3.4 plots the sums of the β_s coefficients from specification (3.2) for event days $s = -5$ through $s = t$ (estimated for all firm-days, inside and outside of event windows). The former shows a positive cumulative abnormal return during almost all trading days within the event window while the latter indicates a negative cumulative abnormal return in all trading days within the event window.

In what follows, I describe two avenues that might account for the discrepancy. First, note that (3.2) includes variables in the estimation (the N_{it}) that will affect the β_s coefficient estimates while being completely absent from the computation of the means in Figure 3.2. Second, and perhaps more importantly, the samples used to construct the two figures are different. In order to compute the means in Figure 3.2, I limited the firm-days to only those appearing in exactly one event window at a time, i.e. firm-days for which $\sum_{t=-5}^{25} d_{it} = 1$. I was then able to assign a trading day value (corresponding to the unique trading day dummy variable equalling 1) to that firm-day for the purpose of computing the trading day mean abnormal return. This step was necessary because it is not clear which trading day value to assign to a firm-day that exists in multiple event windows simultaneously.[23] By eliminating firm-days appearing in multiple event windows at the same time, the number of observations is reduced from 9,161 to 8,722 (a 4.79% reduction). The number of observations used in the estimation of (3.2) is 321,275, of which 9,052 firm-days are in at least one event window.[24] Of course, estimation of (3.2) easily accommodates instances where a firm-day is in more than one event window at a time.

Next, taking into account the two features described above, I try to generate means and coefficients that are more directly comparable. Thus, in the estimation sample, for each observation for which $\sum d_{it} = x$, I generate exactly x observations (one for each event window that the firm-day is in, including 0 observations if the firm-day is in no event window). The resulting sample has 9,492 observations, each in exactly one event window. I then estimate the following model on this sample via OLS:

$$\frac{\widetilde{AR}_{it}}{d\_pct_{it}} = \alpha + \sum_{t=-5}^{-1} \beta_t d_{it} + \sum_{t=1}^{25} \beta_t d_{it} + \epsilon_{it}. \tag{3.7}$$

where d_{i0} is omitted to avoid perfect multicollinearity. I also compute event day means:

$$\mu_t = n_t^{-1} \sum_{i=1}^{n_t} \frac{\widetilde{AR}_{it}}{d\_pct_{it}} \ \forall t \in [-5, 25]$$

where n_t equals the number of firm-days in event day t.

Of course, because the focus is on *cumulative* abnormal returns through event day

[23]This circumstance applies to any firm owning at least two leases, where a discovery is made on one, and then within 30 trading days, a discovery is made on the other lease, as well.

[24]Missing values for variables in (3.2) for 109 observations accounts for the difference between the number of firm-days in the means and coefficients samples.

t, the objects of interest are

$$\sum^{t} \beta \equiv \begin{cases} \sum_{s=-5}^{-1} \beta_s & \text{if } t < 0, \\ \sum_{s=-5}^{-1} \beta_s + \sum_{s=1}^{25} \beta_s & \text{if } t > 0, \end{cases}$$

and

$$\sum^{t} \mu \equiv \sum_{s=-5}^{t} \left(n_s^{-1} \sum_{i=1}^{n_s} \frac{\widetilde{AR}_{is}}{d\_pct_{is}} \right).$$

For the sample described above, both trends are plotted in Figure 3.19 as "Summed Coefficient Values through t" and "Summed Mean Values through t," respectively.

The summed mean and summed coefficient trends plotted in Figure 3.19 are clearly very closely related, but they are not identical. To account for the disparity, first imagine a categorical variable having S categories (that can be indexed by $s = 1, 2, \ldots, S$) each being a disjoint set; in other words: each individual is in one and exactly one category. Then, for some variable y, let μ_s and β_s represent the s-th category mean for y and the OLS coefficient on the dummy variable for the s-th category with y as the dependent variable, respectively. In an OLS regression on a constant term and indicator variables for $S - 1$ of the S categories,

$$\mu_s = \alpha + \beta_s.$$

Summing over the first $t \leq S$ categories yields the following:

$$\sum_{s=1}^{t} \mu_s = t\alpha + \sum_{s=1}^{t} \beta_s, \tag{3.8}$$

thus relating the summed means and summed OLS coefficients. The two upper trends in Figure 3.19 are consistent with (3.8); their difference is fully accounted for by the linear "Summed Intercept Values through t" trend (the "$t\alpha$" term in (3.8)).

As expected, the "Cumulative Abnormal Returns (% Ownership Adjusted)" trend in Figure 3.2 and the "Summed Mean Values through t" trend in Figure 3.19 have the same shape (if not the same levels; these are not exactly identical because the samples are slightly different – see above). The inclusion of this appendix is motivated, however, by the fact that the "Summed Coefficients" trend in Figure 3.4 and the "Summed Coefficient Values through t" trend in Figure 3.19 appear so differently. The principal difference between the two graphs is in the handling of firm-days that appear in more than one event window simultaneously in the samples used to generate the graphs. Apparently, inclusion of these observations as they appear in the data (rather than in the synthetic way used to created Figure 3.19) very negatively affects the coefficient estimates. That this is the case is made clear by the conditional means. For the 8,622 firm-days appearing in exactly one event window, the mean abnormal return (in millions of dollars of market capitalization) is 15.02. The corresponding mean for the 430 firm-days appearing in more than one event window on the given trading day is -45.44.

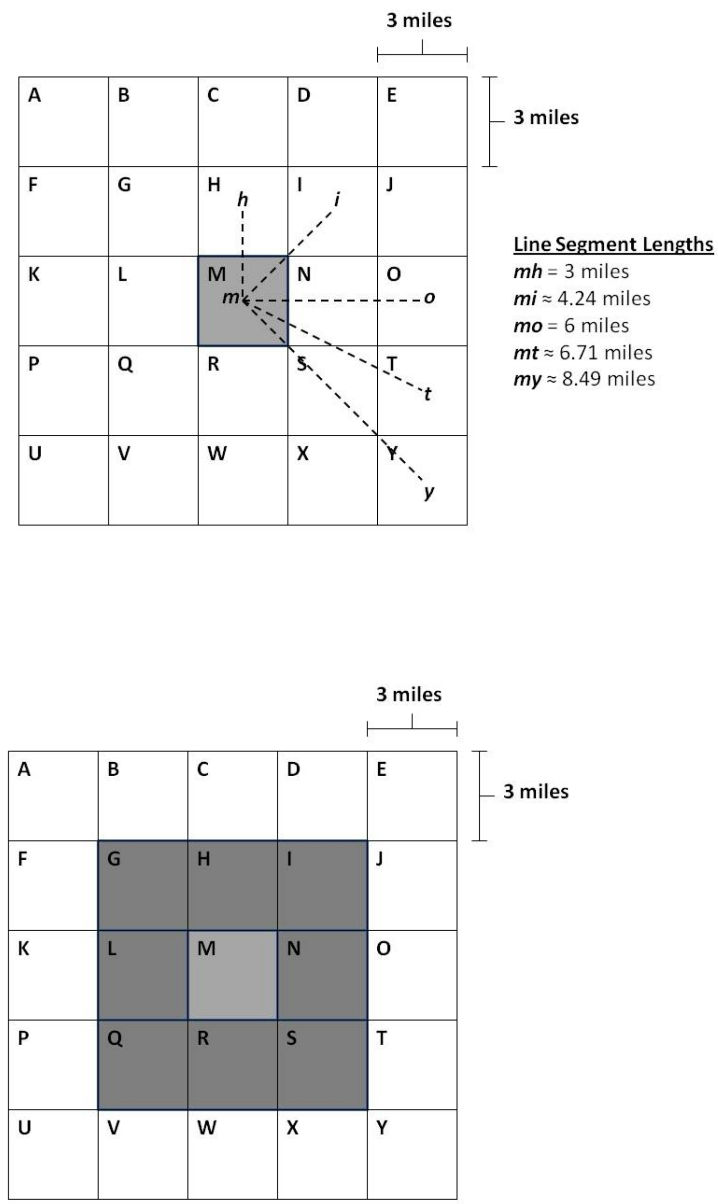


Figure 3.1: Set of neighbor blocks for a lease of standard size and shape.

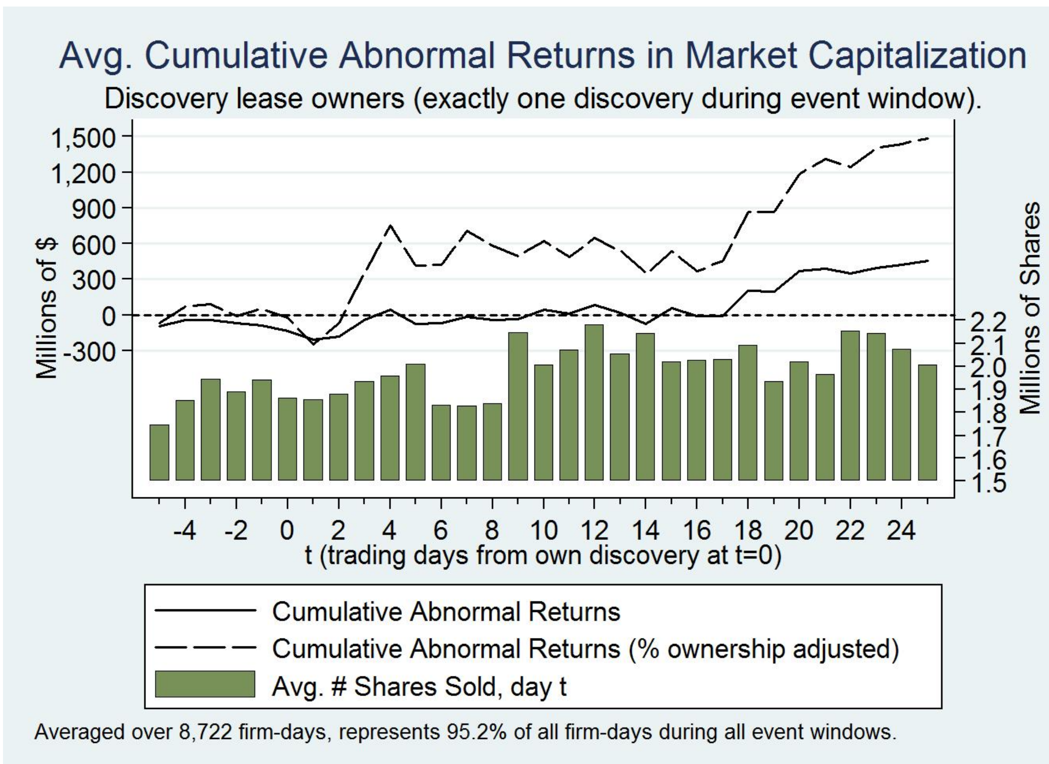


Figure 3.2: Mean cumulative abnormal returns (weighted by market capitalization, then averaged) for publicly-traded firms that own discovery leases.

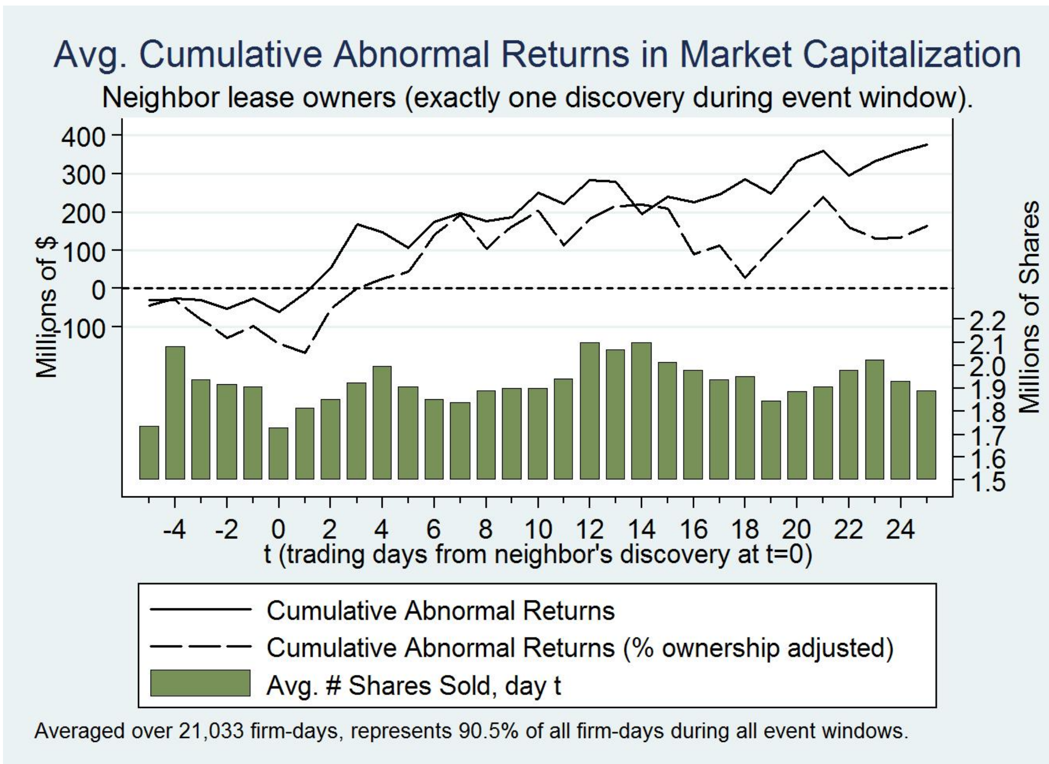


Figure 3.3: Mean cumulative abnormal returns (weighted by market capitalization, then averaged) for publicly-traded firms owning leases that neighbor a discovery lease.

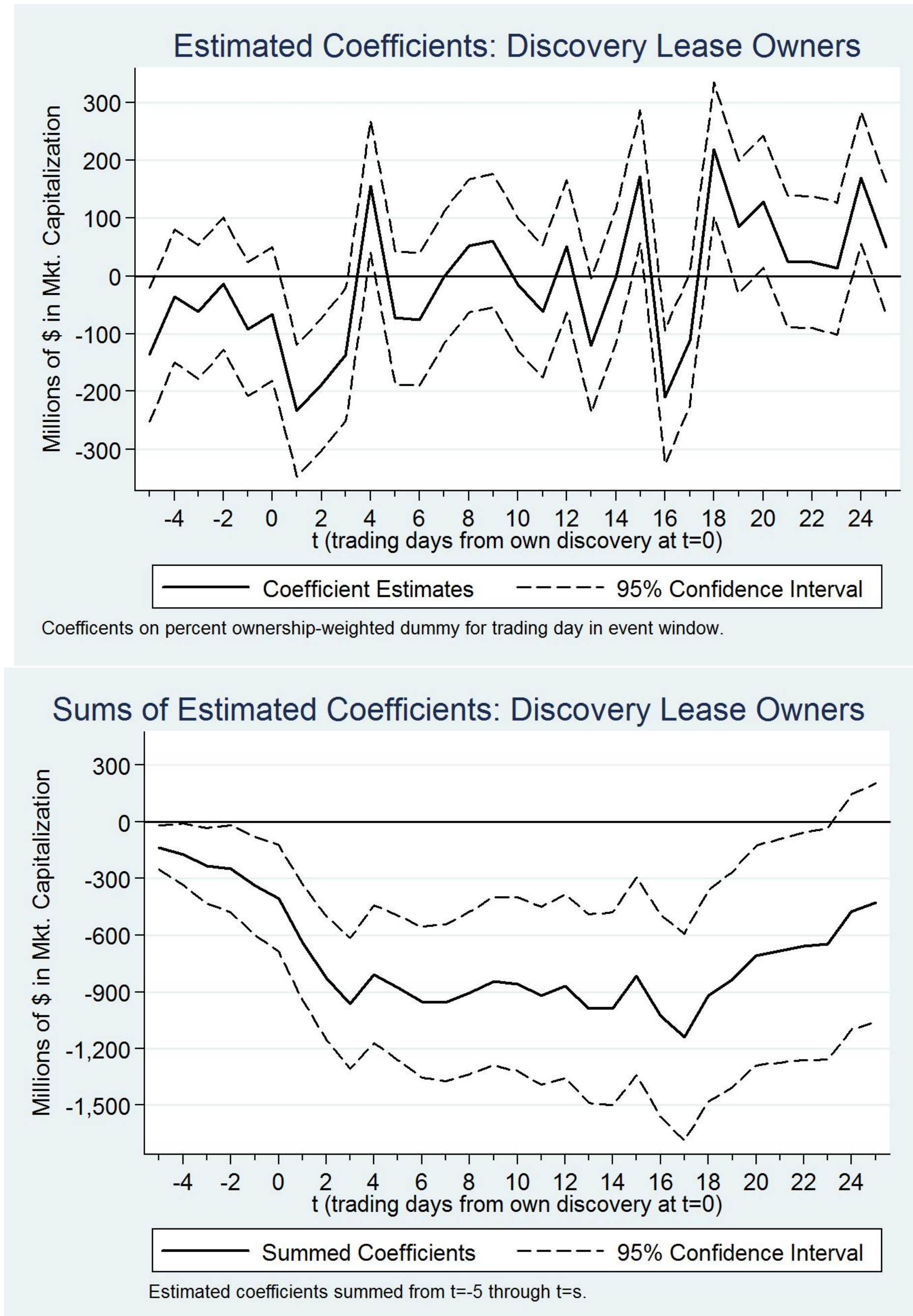


Figure 3.4: Coefficient estimates: β_t and $\sum \beta_t$ in (3.2).

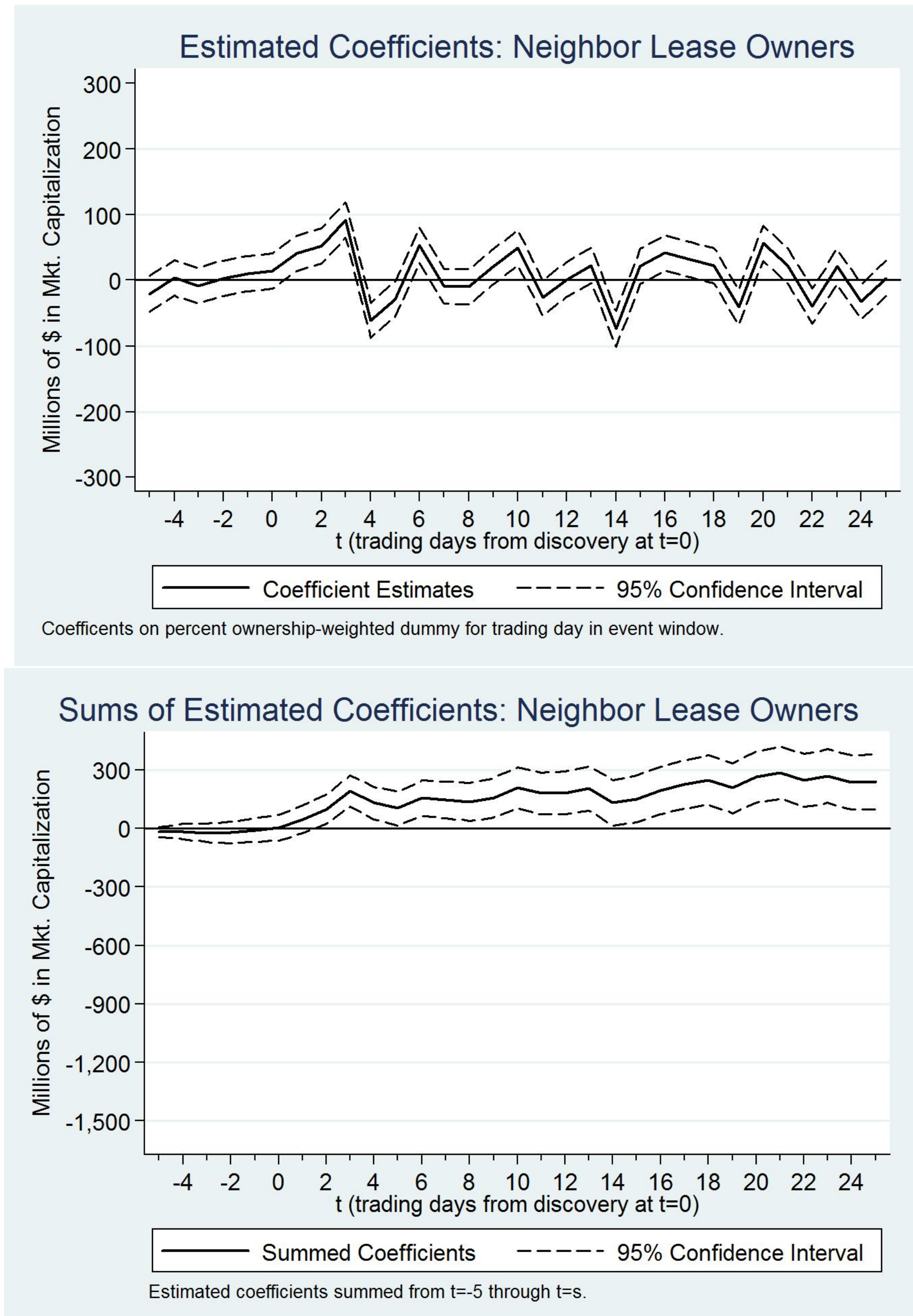
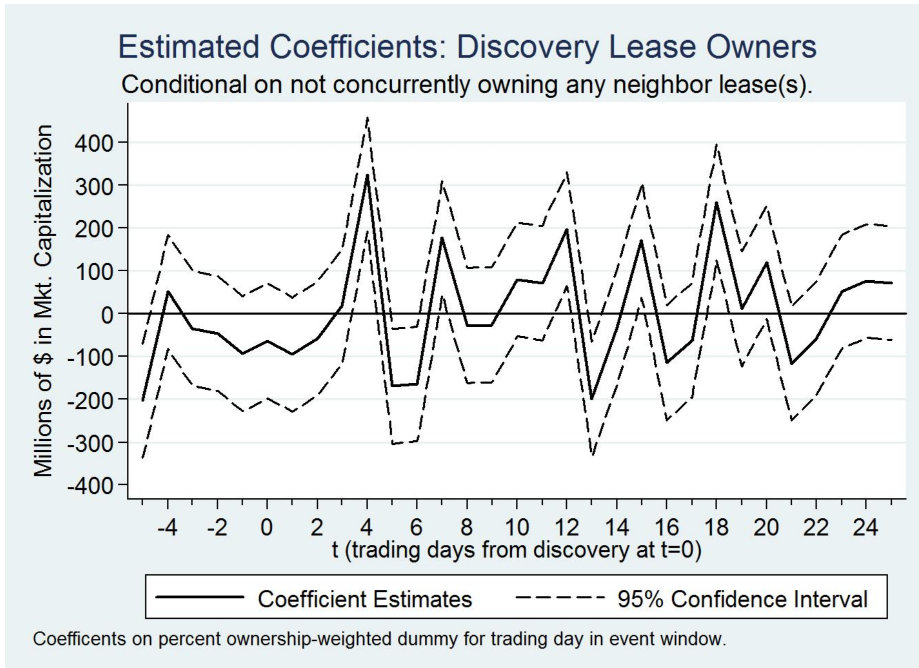


Figure 3.5: Coefficient estimates: γ_t and $\sum \gamma_t$ in (3.2).



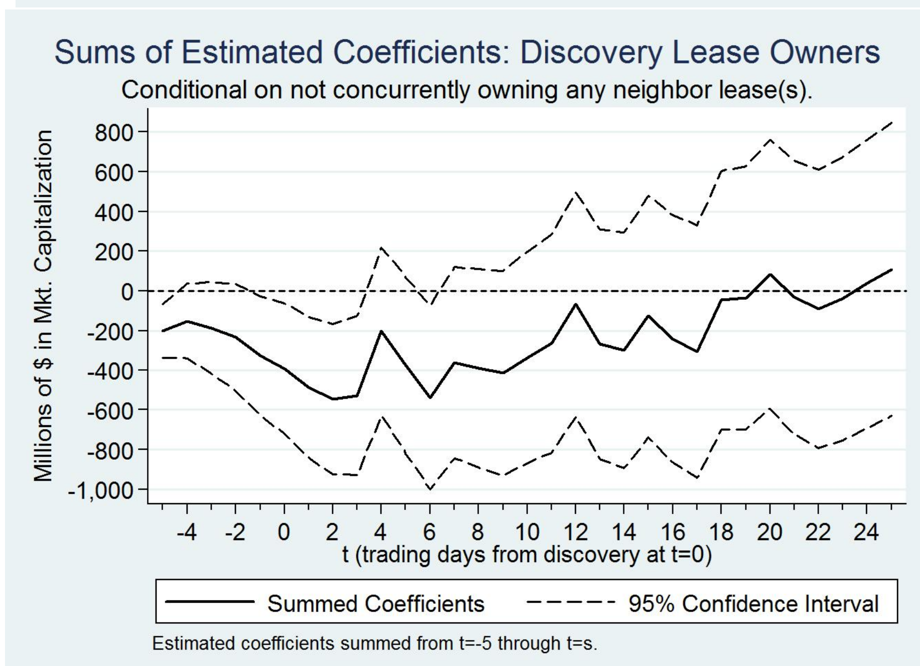
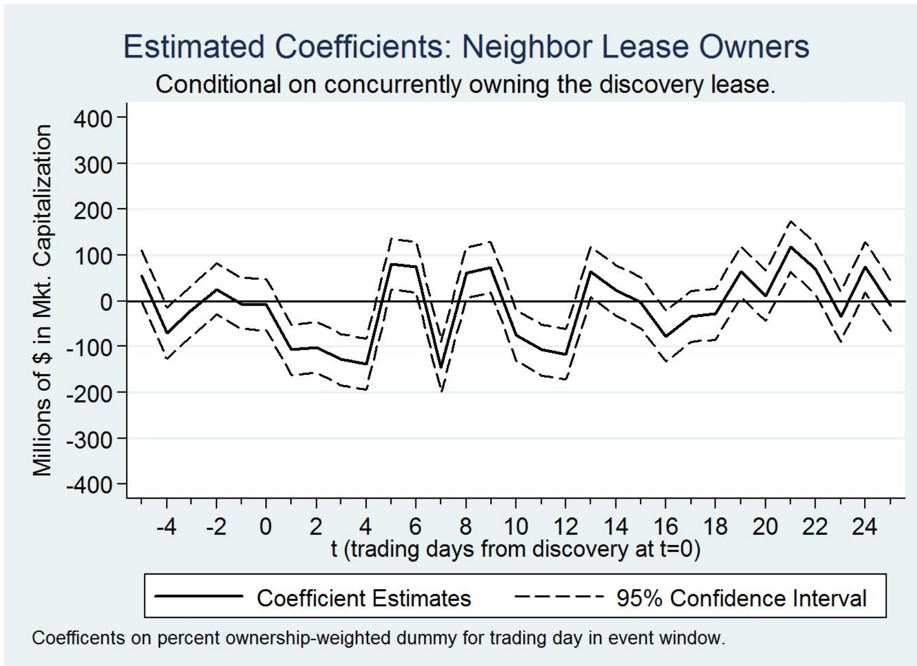


Figure 3.6: Coefficient estimates: β_t and $\sum \beta_t$ in (3.3).



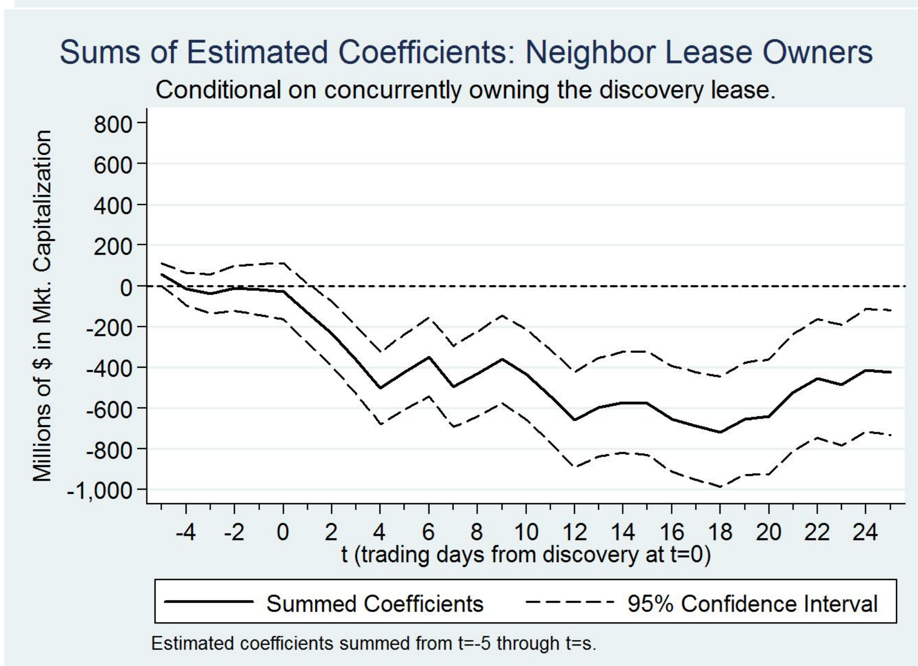
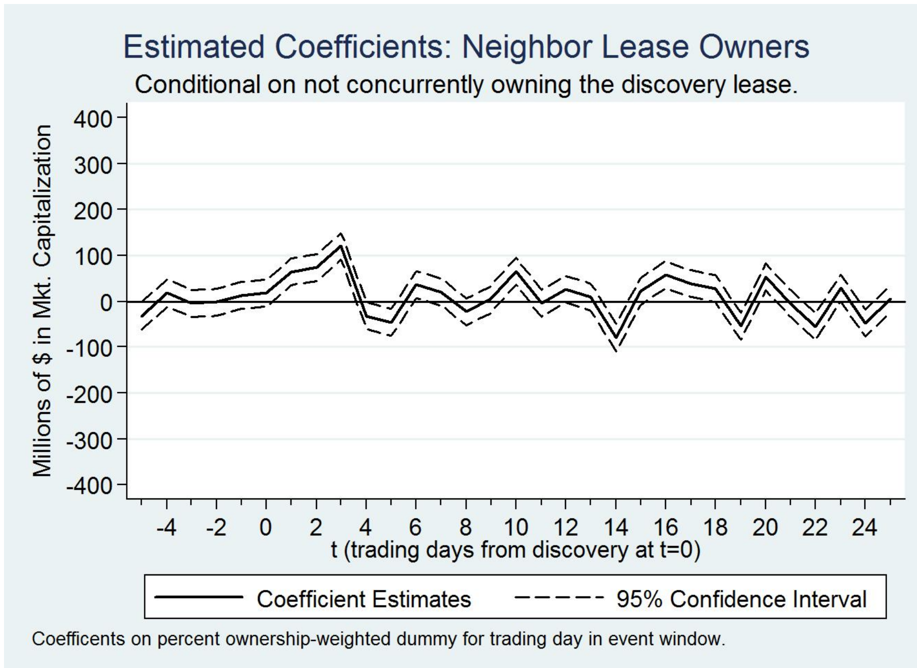


Figure 3.7: Coefficient estimates: δ_t and $\sum \delta_t$ in (3.3).



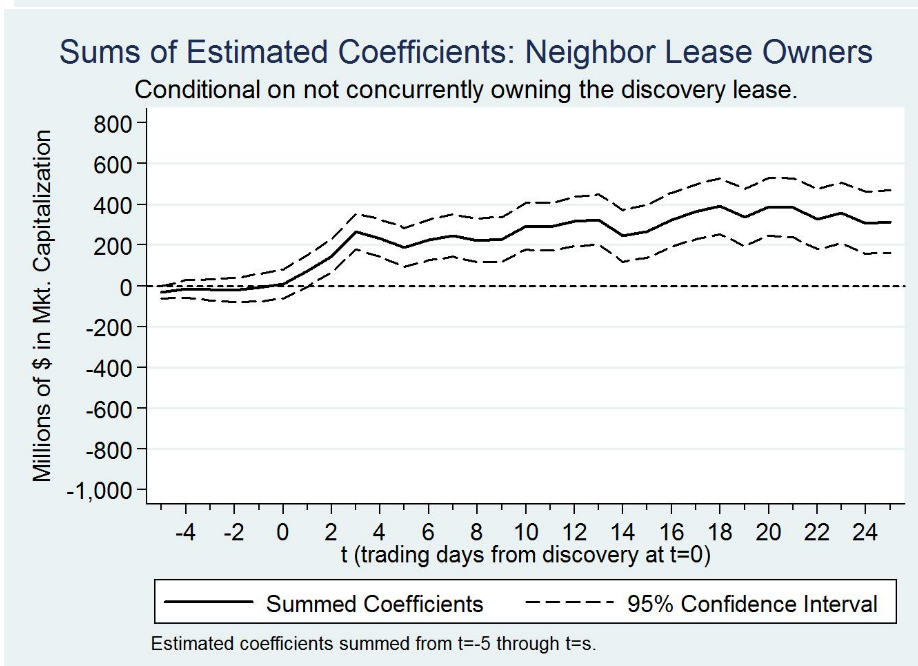


Figure 3.8: Coefficient estimates: γ_t and $\sum \gamma_t$ in (3.3).

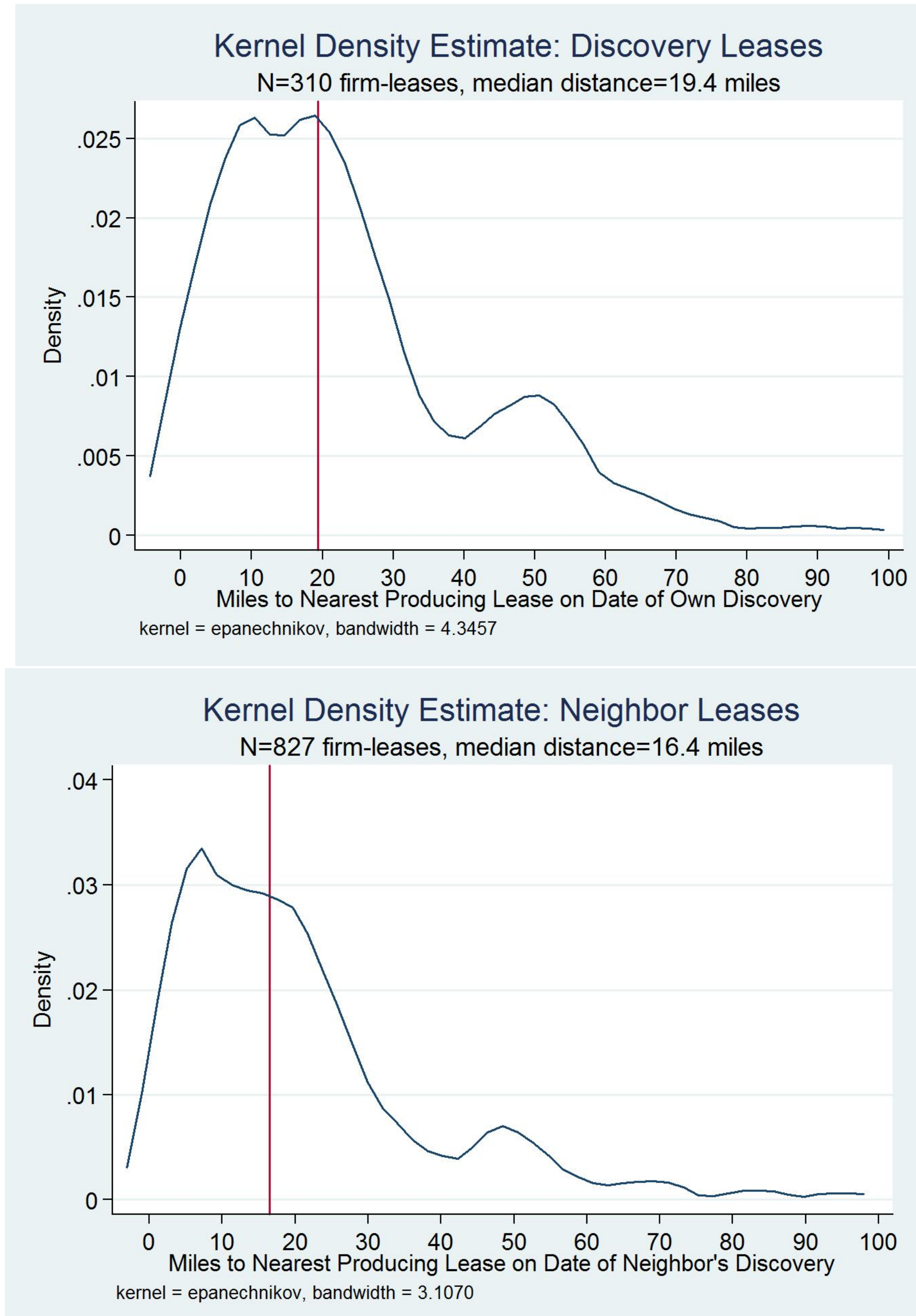
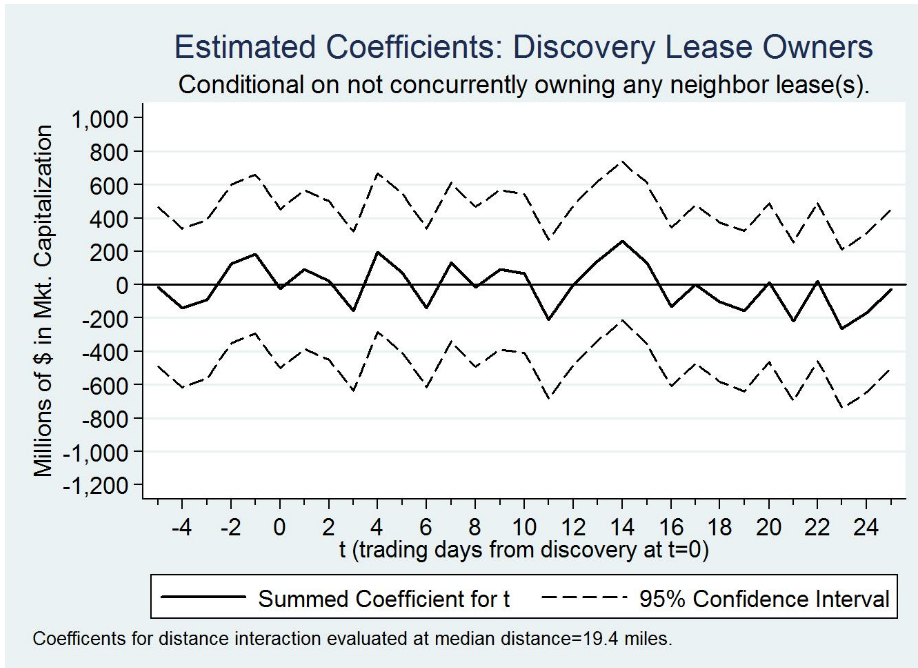


Figure 3.9: Distributions of distance variable for discovery and neighbor leases.



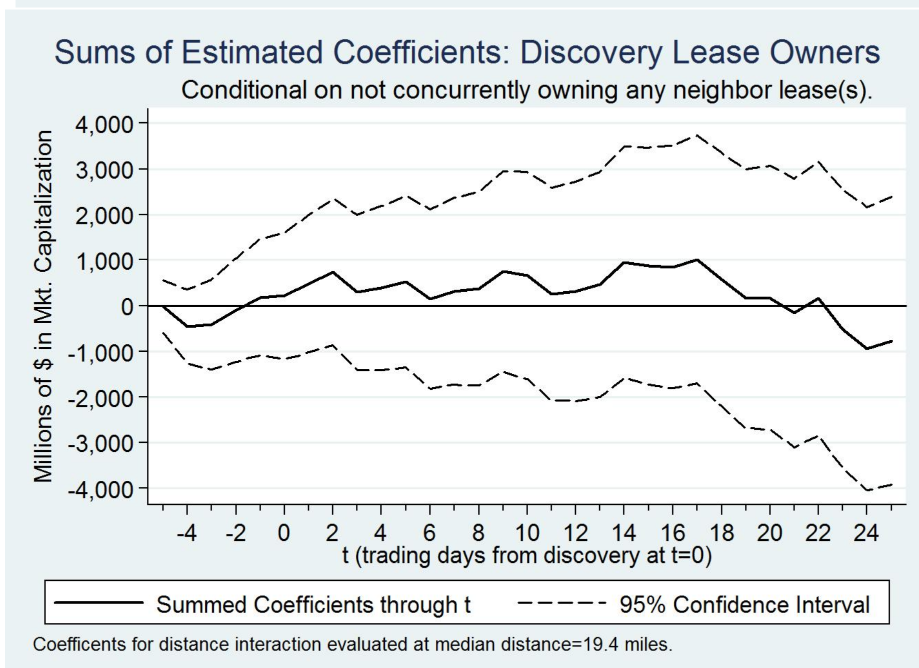
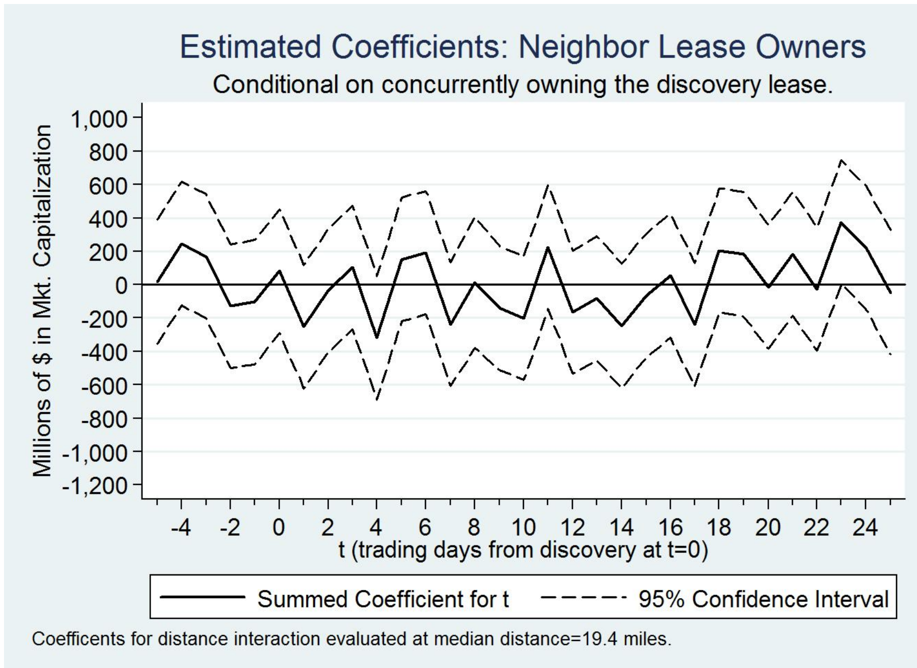


Figure 3.10: Coefficient estimates: $(\beta_t + \zeta_t d\_dist_{it})$ and $\sum(\beta_t + \zeta_t d\_dist_{it})$ in (3.4).



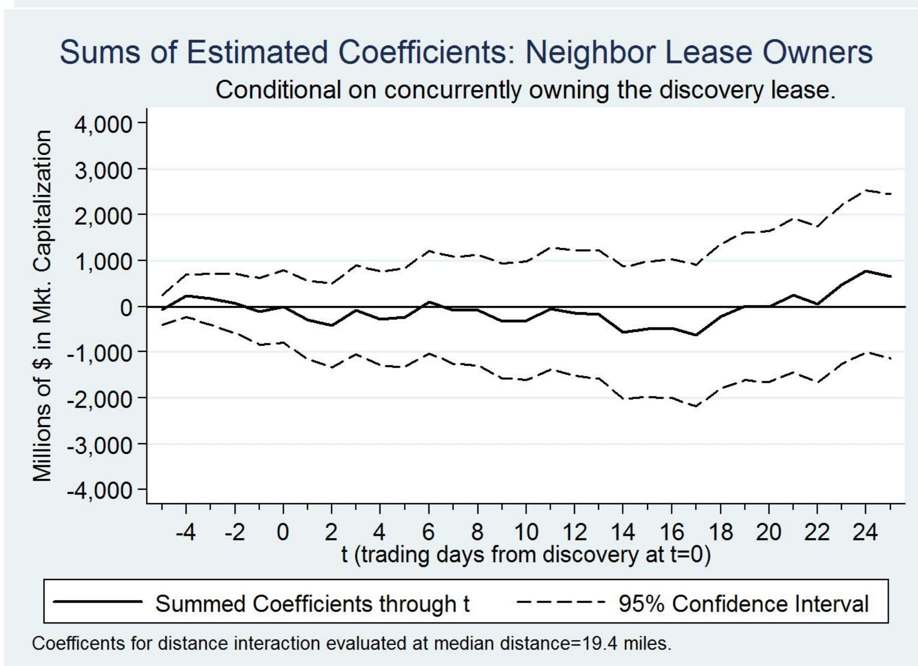


Figure 3.11: Coefficient estimates: $(\delta_t + \theta_t d\_dist_{it})$ and $\sum(\delta_t + \theta_t d\_dist_{it})$ in (3.4).

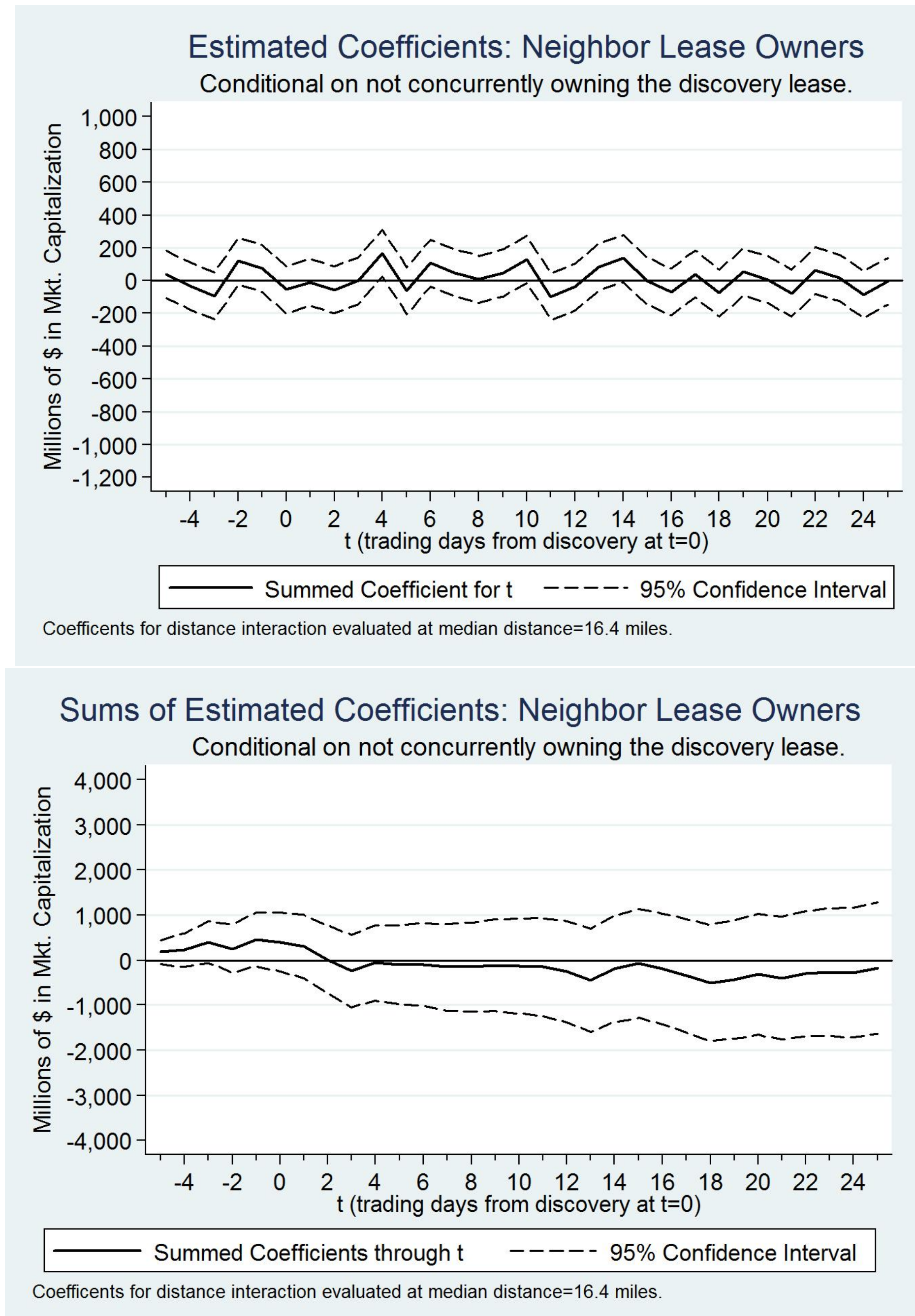
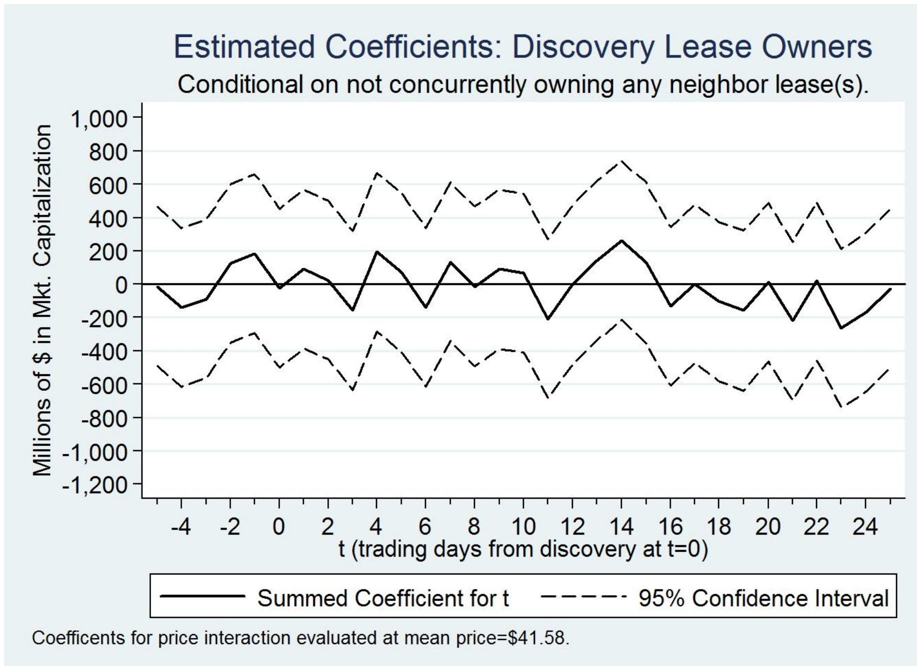


Figure 3.12: Coefficient estimates: $(\gamma_t + \eta_t d\_dist_{it})$ and $\sum(\gamma_t + \eta_t d\_dist_{it})$ in (3.4).



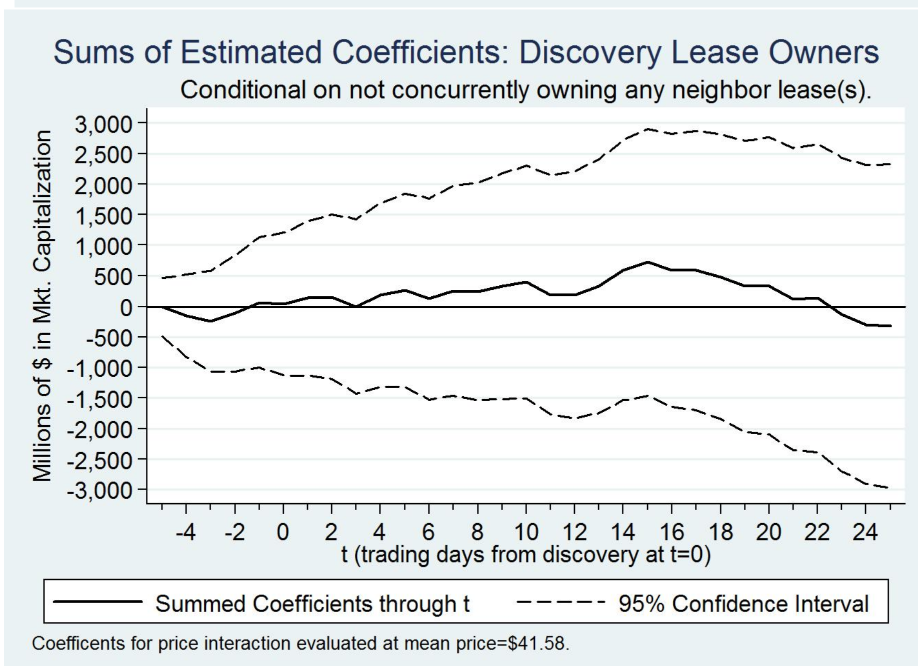
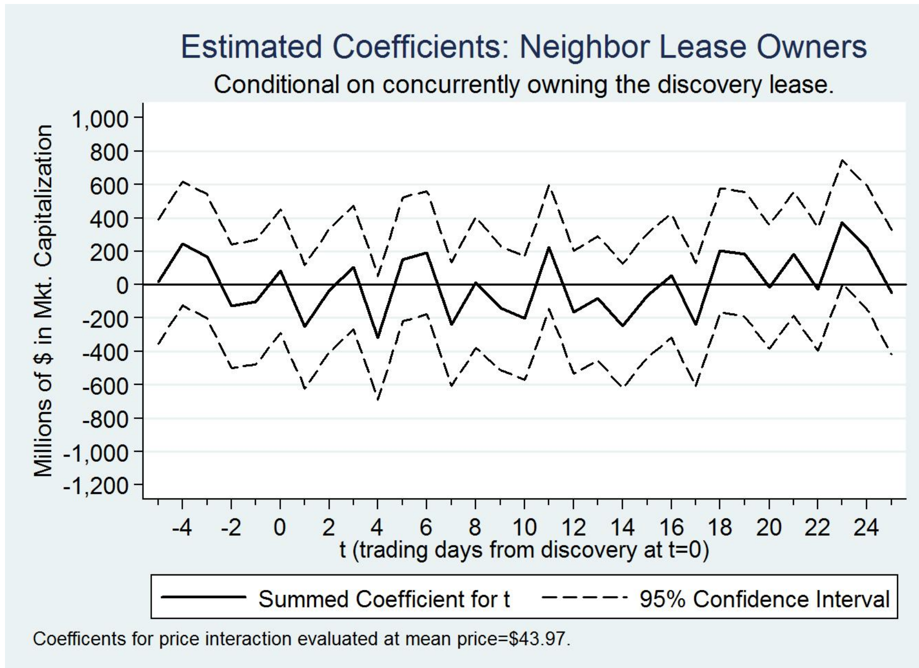


Figure 3.13: Coefficient estimates: $(\beta_t + \iota_t p_0)$ and $\sum(\beta_t + \iota_t p_0)$ in (3.5).



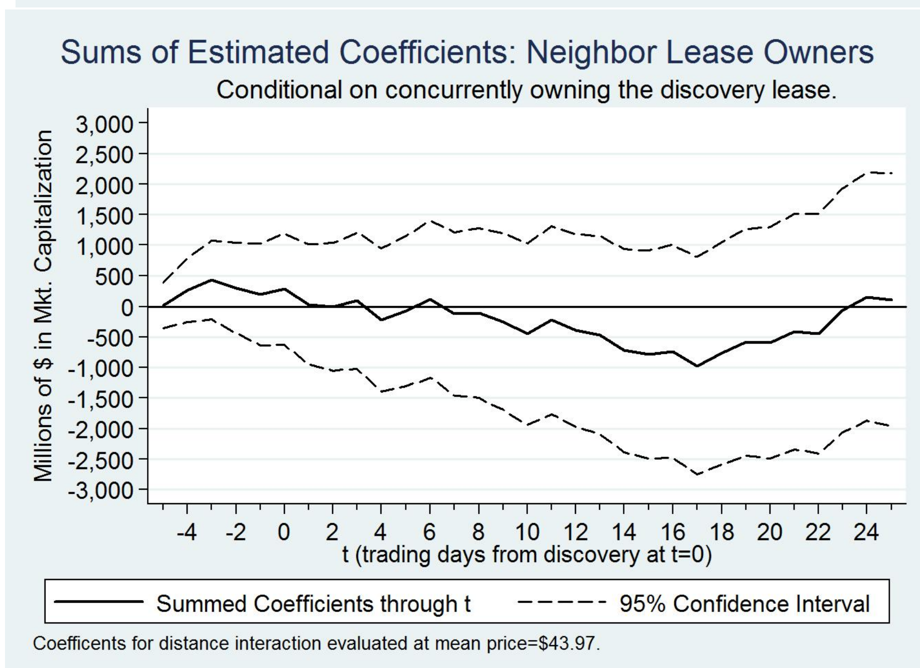
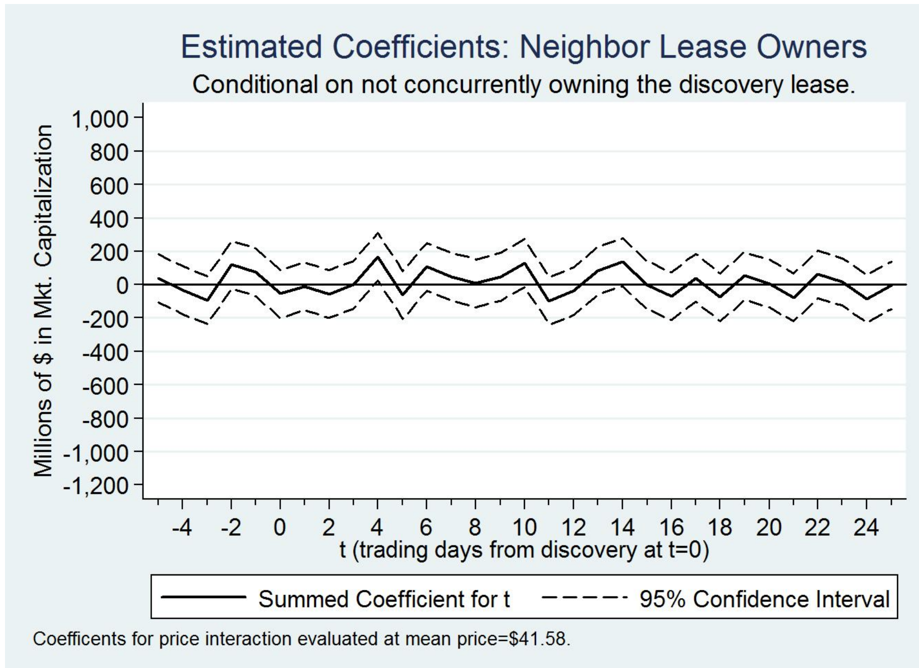


Figure 3.14: Coefficient estimates: $(\delta_t + \lambda_t p_0)$ and $\sum(\delta_t + \lambda_t p_0)$ in (3.5).



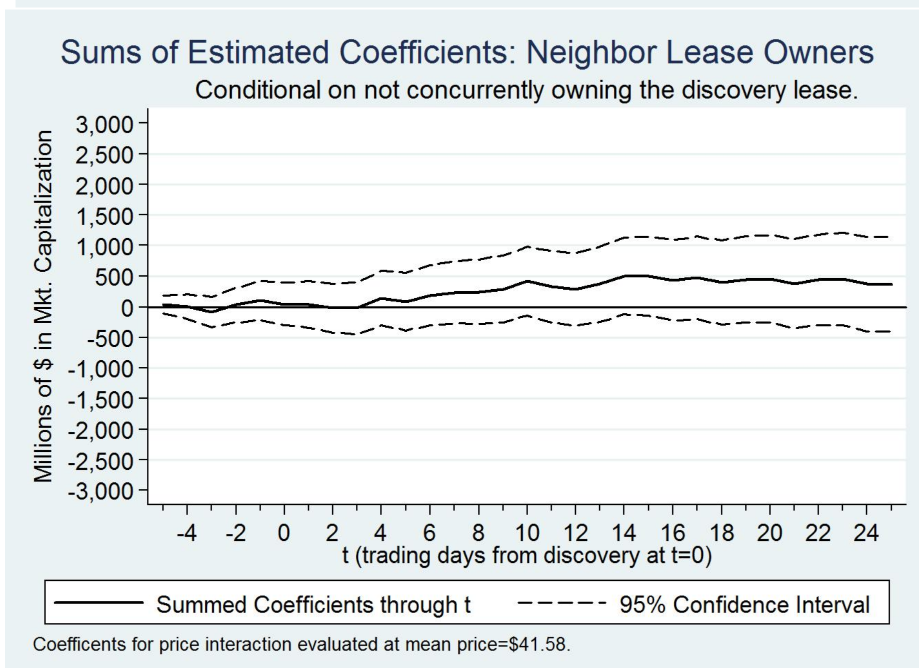


Figure 3.15: Coefficient estimates: $(\gamma_t + \kappa_t p_0)$ and $\sum(\gamma_t + \kappa_t p_0)$ in (3.5).

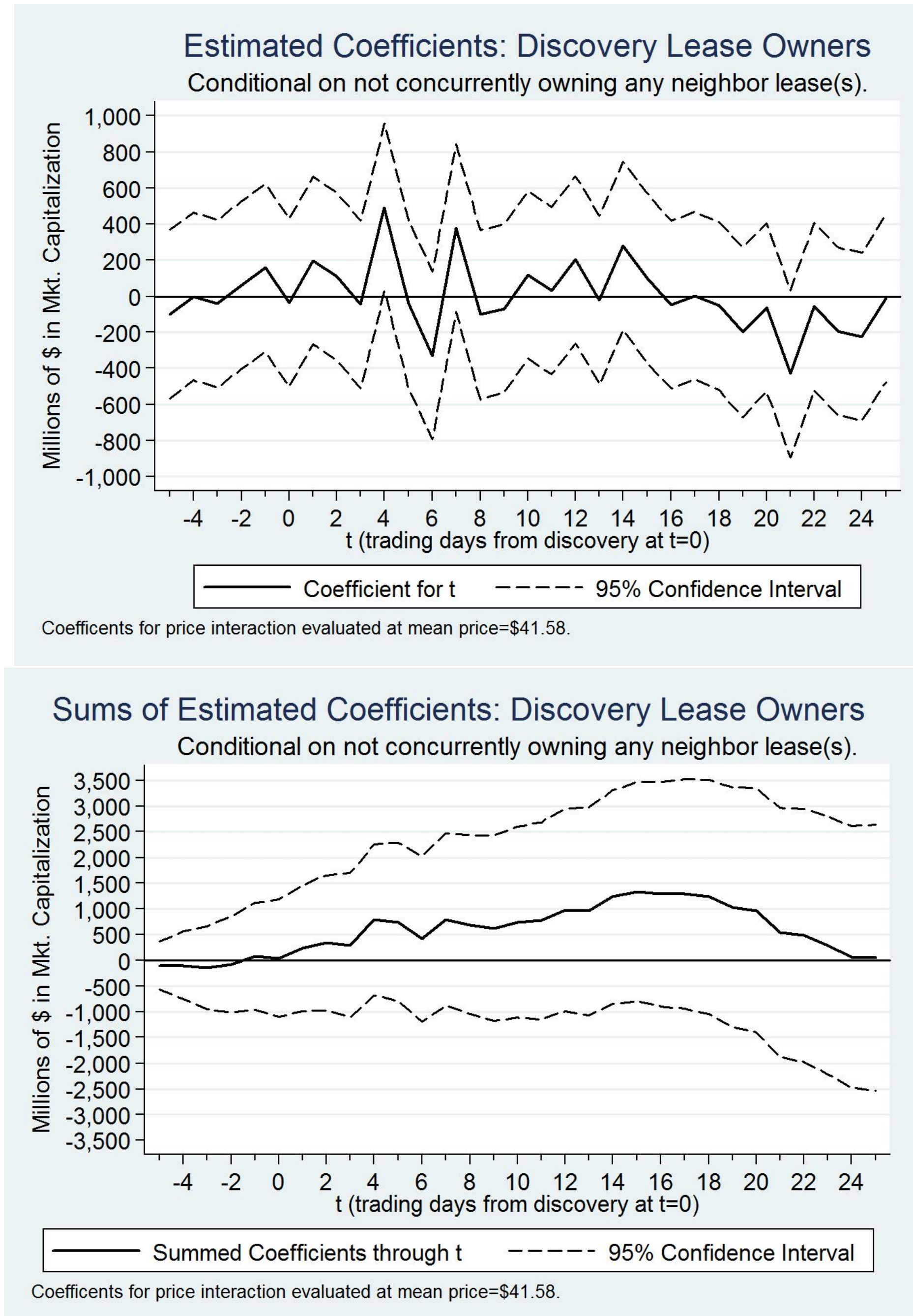
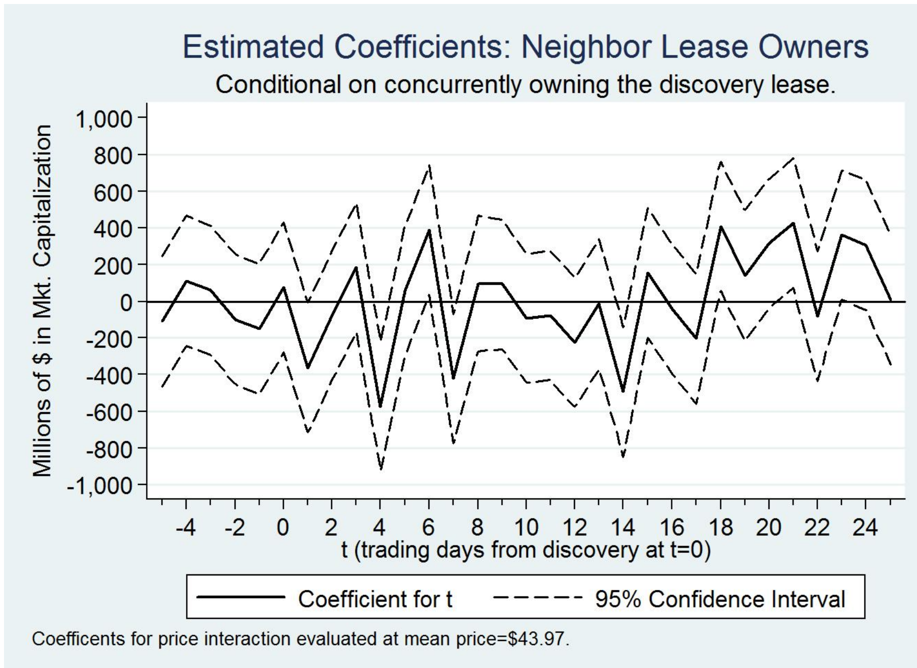


Figure 3.16: Coefficient estimates: $\iota_t p_0$ and $\sum \iota_t p_0$ in (3.6).



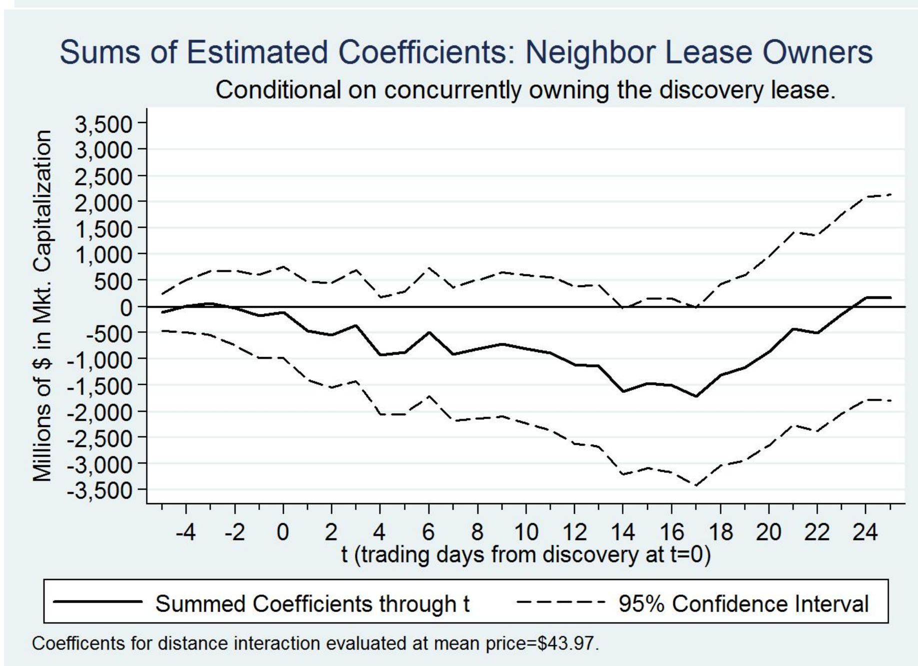
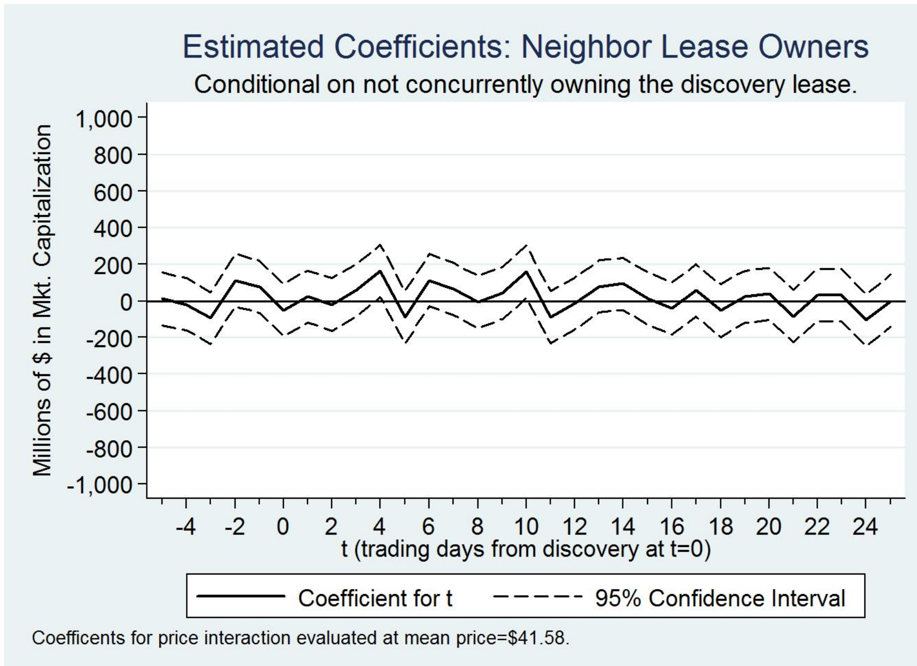


Figure 3.17: Coefficient estimates: $\lambda_t p_0$ and $\sum \lambda_t p_0$ in (3.6).



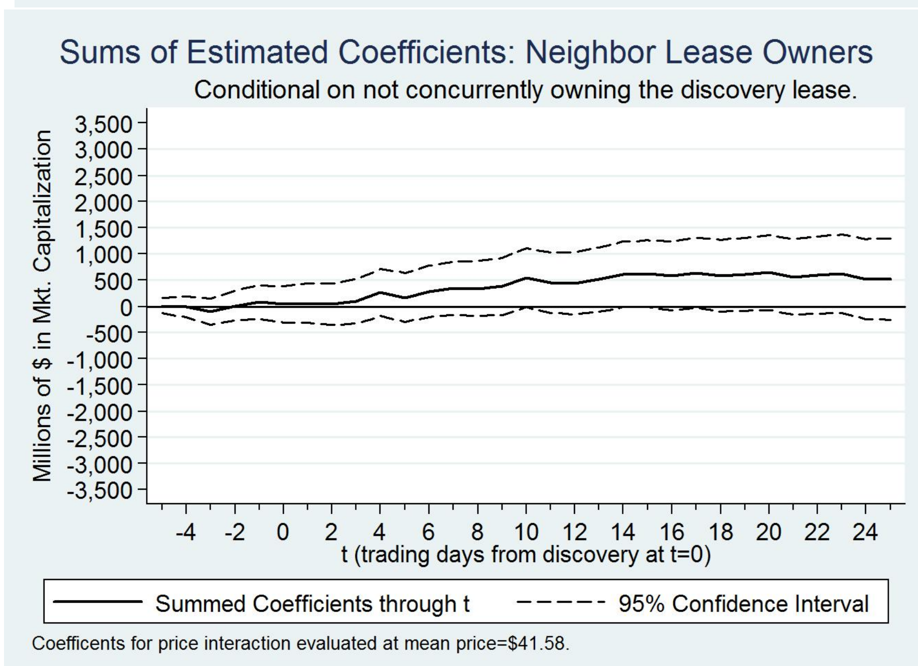


Figure 3.18: Coefficient estimates: $\kappa_t p_0$ and $\sum \kappa_t p_0$ in (3.6).

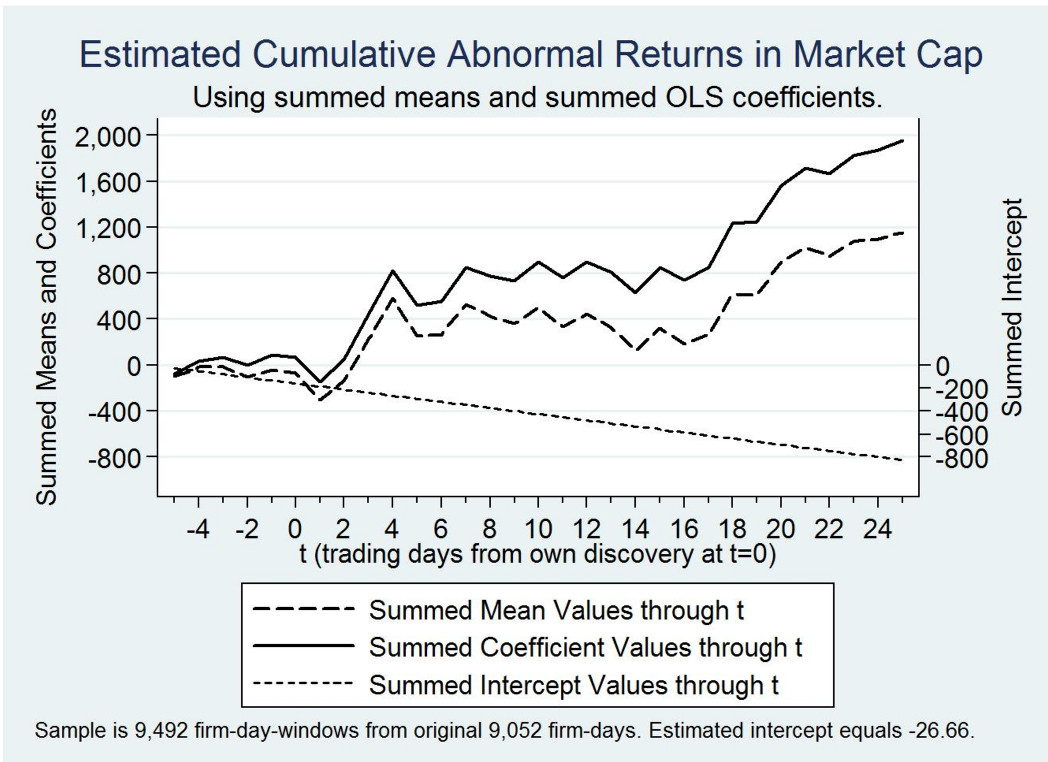


Figure 3.19: Comparison of cumulative abnormal returns computed using means and OLS estimates.

	D_{it}		N_{it}	
Event Day	$\hat{\beta}_t$	S.E.	$\hat{\gamma}_t$	S.E.
-5	-136.0*	(59.0)	-20.3	(13.9)
-4	-35.4	(58.6)	3.6	(13.8)
-3	-62.0	(58.8)	-7.7	(13.7)
-2	-13.6	(58.6)	3.2	(13.8)
-1	-91.7	(58.8)	10.6	(13.7)
0	-65.7	(58.8)	13.9	(13.7)
1	-233.1***	(58.2)	41.3**	(13.6)
2	-187.3**	(58.4)	52.6***	(13.7)
3	-136.2*	(58.5)	92.3***	(13.7)
4	155.0**	(58.2)	-60.7***	(13.6)
5	-72.5	(58.8)	-28.6*	(13.7)
6	-75.3	(58.6)	53.5***	(13.7)
7	-2.7	(58.2)	-9.2	(13.6)
8	51.6	(58.8)	-10.0	(13.7)
9	61.1	(58.7)	20.5	(13.7)
10	-14.4	(58.4)	50.1***	(13.6)
11	-61.3	(58.2)	-26.9*	(13.6)
12	51.1	(58.2)	1.6	(13.6)
13	-120.1*	(59.1)	23.1	(13.9)
14	-0.2	(59.0)	-73.8***	(13.8)
15	171.5**	(58.7)	21.2	(13.7)
16	-210.1***	(58.9)	42.0**	(13.7)
17	-110.5	(58.3)	31.9*	(13.7)
18	218.5***	(59.0)	22.0	(13.7)
19	84.5	(58.5)	-40.9**	(13.7)
20	128.0*	(58.1)	56.6***	(13.6)
21	24.8	(58.1)	22.4	(13.6)
22	23.8	(58.1)	-39.3**	(13.6)
23	12.6	(58.2)	21.0	(13.7)
24	169.8**	(58.3)	-31.9*	(13.7)
25	49.1	(58.1)	3.0	(13.6)
N	321,275			
R^2	0.001			

Intercept estimate is 1.5 with standard error of 0.9.
Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 3.1: Estimates for baseline specification (3.2).

	D_{it}		N_{it}		$D_{it}N_{it}$	
Event Day	$\hat{\beta}_t$	S.E.	$\hat{\gamma}_t$	S.E.	$\hat{\delta}_t$	S.E.
-5	-203.5**	(68.3)	-32.1*	(15.2)	54.7	(28.6)
-4	51.2	(67.9)	17.6	(15.1)	-70.2*	(28.5)
-3	-35.0	(68.4)	-4.0	(15.0)	-21.7	(28.2)
-2	-46.8	(68.3)	-2.2	(15.0)	25.7	(28.6)
-1	-93.3	(68.6)	12.5	(15.0)	-6.1	(28.4)
0	-64.1	(68.6)	17.9	(15.0)	-8.5	(28.6)
1	-95.6	(67.8)	64.0***	(14.8)	-107.3***	(28.1)
2	-58.2	(68.0)	73.5***	(14.9)	-102.2***	(28.4)
3	17.3	(68.1)	119.9***	(14.9)	-128.2***	(28.6)
4	324.3***	(67.8)	-32.0*	(14.8)	-138.0***	(28.1)
5	-170.3*	(68.3)	-45.9**	(14.9)	79.5**	(28.2)
6	-164.3*	(68.2)	36.5*	(14.9)	73.9**	(28.2)
7	176.8**	(67.8)	20.5	(14.8)	-144.9***	(28.1)
8	-28.2	(68.8)	-22.8	(14.9)	61.1*	(28.3)
9	-26.5	(68.6)	4.5	(14.9)	72.9**	(28.3)
10	79.3	(67.8)	65.6***	(14.9)	-74.7**	(28.2)
11	71.1	(67.9)	-3.8	(14.9)	-107.4***	(28.2)
12	197.3**	(67.8)	25.8	(14.8)	-116.6***	(28.1)
13	-200.1**	(68.5)	9.5	(15.1)	62.8*	(28.3)
14	-31.6	(68.4)	-79.1***	(15.1)	22.8	(28.2)
15	171.3*	(68.5)	21.5	(14.9)	-3.4	(28.2)
16	-114.5	(68.7)	58.4***	(14.9)	-77.1**	(28.2)
17	-62.4	(67.8)	38.1*	(14.9)	-34.4	(28.2)
18	259.7***	(68.8)	27.2	(15.0)	-29.1	(28.5)
19	10.4	(68.3)	-54.8***	(14.9)	63.4*	(28.2)
20	119.5	(67.6)	53.0***	(14.8)	11.5	(28.1)
21	-116.8	(67.6)	-5.0	(14.8)	118.2***	(28.1)
22	-57.9	(67.6)	-55.5***	(14.8)	70.1*	(28.1)
23	51.0	(67.8)	28.5	(14.9)	-34.1	(28.3)
24	76.0	(67.9)	-47.4**	(15.0)	73.8**	(28.3)
25	70.9	(67.6)	5.4	(14.8)	-10.5	(28.1)
N	321,275					
R^2	0.002					

Intercept estimate is 1.2 with standard error of 0.9.

Standard errors in parentheses

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

Table 3.2: Estimates for specification (3.3).

CHAPTER IV

Secondary Recovery and Oil Price

4.1 Introduction

In order for the economic value of underground oil to be realized, it must either be pumped from its reservoir by applying energy from the surface or it must be forced upwards by pressure from the reservoir, itself. In the latter case, as production persists, the pressure from the reservoir is dissipated meaning that less oil is produced per unit effort and time. In some circumstances, however, the operator can counteract this effect by injecting water into the formation. With this research, I examine how the amount of water injected, conditional on the well being able to inject, is affected by the price of oil. I find that a \$1 increase in average monthly oil price increases the monthly volume of water injected by 647 to 964 barrels, though these coefficient estimates are not necessarily robust to different estimators for the error matrix.

This research has implications for the collection of royalties from older oil and gas fields where injection occurs. The royalty, a percentage tax applied directly to the per unit price of oil or natural gas (either $\frac{1}{6}$ or $\frac{1}{8}$ for production from the U.S. Gulf of Mexico), is equivalent to a price decrease from the standpoint of the hydrocarbon producer. With injection being sensitive to price, the implication is that the presence of the royalty will lessen the amount of injection carried out on older fields and therefore ultimately lower production. This represents a less obvious but still potentially important inefficiency due to royalty collection. Additional research that explicitly quantifies the increase in ultimate production for a specific level of injection, in concert with these results, could allow for the estimation of this particular aspect of the total welfare loss due to the royalty.[1]

This area of research has received little attention. Amit (1986) theoretically examines the question of when to switch from not injecting to injecting during production from the reservoir. While his model generates a number of implications, he does not test them empirically. A recent paper that is empirical in nature is Rao (2009), however, she examines production rather than injection. Using data for onshore oil wells during 1977-2008, she exploits variation in the federal Windfall Profit Tax to estimate an after-tax price elasticity of production of roughly 0.23.

The remainder of the paper proceeds as follows: in section 2, I provide relevant background on oil production. In section 3, I describe the data used and how I compiled it in order to conduct the analysis. I present a theory of optimal production during the secondary recovery phase in section 4. In section 5, I present and discuss the results. Section 6 concludes.

4.2 Background

Given that any underground reservoir containing fluids such as oil, water, and natural gas is a high temperature and high pressure environment, these fluids will be compressed relative to their densities at surface temperature and pressure conditions. Any reduction in pressure on these fluids will cause them to increase in volume[2] The expansion of fluids still in the reservoir in response to the removal of some volume

[1] Note that although the most logical object to estimate for these purposes is the price elasticity of injection, estimation of this parameter, at least using a log-log specification, is complicated by the fact that the injected volume in most months for an injection-capable string is zero.

[2] The actual drop in pressure (dP) for a change in the volume of fluid (dV) will be governed by the "compressibility," C, of the reservoir fluids, according to the following relationship: $dP = -\frac{1}{C} \cdot \frac{dV}{V}$. Rearrangement of this expression yields the formula for compressibility: $C \equiv -\frac{1}{V} \cdot \frac{dV}{dP}$, which is defined as "the fractional change in volume per unit change in pressure" (Jahn et al. (1998)).

of other fluid acts as a source of drive energy to support "primary recovery" – i.e. pressure from the reservoir itself drives the resource to the surface (Jahn et al. (1998)). Of course the expansion of these fluids depends very much on the specific attributes of the given reservoir and its fluids. For example, oil's compressibility depends on the amount of dissolved gas it holds, which if it occurs in very small amounts lowers the oil's compressibility resulting in large pressure drops in the reservoir after only limited oil production. In the instance where oil expansion is the sole method of support for pressure in such a reservoir, conditions for abandonment of the formation will be reached rapidly with total production amounting to less than 5% of the oil originally in place (Jahn et al. (1998)).

When possible, injection provides a potential remedy to such situations. Otherwise known as "secondary recovery," this constitutes the adding of energy to the reservoir by injecting fluids (usually water or gas) in order to maintain the reservoir's pressure as production occurs (Jahn et al. (1998)). The actual injection is carried out via a well, and in the case of offshore production, water is gathered on site and then forced into the reservoir. Two important and related distinctions need be made between the primary and secondary recovery phases. First, the operator does not incur any cost to displace the resource to the surface during the former, while in the course of the latter, it does (e.g. the cost of injecting water into the reservoir). Second, in the primary recovery stage, the producer does not directly control the recovery rate (it is just due to natural drive), but during the secondary recovery stage, the operator selects the production rate (Amit (1986)). Finally, it should be noted that after the primary and even secondary recovery phases, 40-85% of hydrocarbons are usually not recovered, especially for oil fields (Jahn et al. (1998)). Although not examined in the paper, more costly and technically challenging methods know collectively as "enhanced oil recovery" (EOR) are oftentimes then applied to reservoirs in order to increase the ultimate recovery.[3]

4.3 Data

The Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE, the successor agency to the Mineral Management Service) requires that entities holding any federal oil and gas leases submit a monthly "Oil and Gas Operations Report" (OGOR-A) for each well, from the month that drilling is concluded until the month the well is plugged and permanently abandoned (Minerals Management Service (2002), page 2-6). Along with total oil production (in barrels) and natural gas production (in thousand of cubic feet), the leaseholder reports the total barrels of water injected into the reservoir via the well during the course of the month. The OGOR-A form can be seen in Figure 4.1; the space for reporting water (or gas, in the case of gas injection) injection volume is marked with "21." The instructions for filling in this entry are straightforward: "Enter the volume of oil, gas, or water injected into the well" (Minerals Management Service (2002), page 5-9).

BOEMRE has collected OGOR data since 1947 and makes the data available online from 1996 onwards. For a nominal fee, I purchased from BOEMRE the entire 1947-2011 panel of OGOR-A data collected for production on federal leases in the U.S. Gulf of Mexico.[4] The basic cross sectional unit in these data goes by any of the following names: a "production string," "production tubing," or "tubing string," and I will refer to them as "strings" in the remainder of the text. An individual string can be thought of as a hose that conveys material from the reservoir to the surface (in the case of production) or vice-versa (in the case of injection). A path from a hole drilled in the seabed (a wellhead) to a unique bottom location constitutes a well, in which multiple strings might operate simultaneously. Similarly, multiple wells might

[3]EOR techniques include steam injection, in-situ combustion, miscible fluid displacement, and polymer augmented water flood.

[4]I bought the data at https://www.gomr.boemre.gov/WebStore/front.asp for $80.

originate at the same wellhead. Finally, the individual unit of production is the lease, and different leases associated with the same geological configuration are grouped into the same field (by determination of BOEMRE).

The 1947-2011 OGOR-A panel has 7,400,832 observations, each representing a string-month for an oil or gas lease in the U.S. Gulf of Mexico during that period.[5] Closer examination of these data reveals that some strings report their well status as abandoned starting at some month in the data and then continue to report abandonment for all subsequent months in the sample.[6] Starting from the first month that one of these strings reports a code for abandonment, I drop the strings for that month and for all subsequent months (if in all subsequent months the string is also reported as abandoned).

With the removal of all string-months for strings subsequent to that string being rendered incapable or production or injection, the remaining OGOR-A data has 6,694,738 observations. While some string-months are reported to be used for water injection as early as 1967 (according to the well status variable in the OGOR-A data), the variable that measures water injection is 0 for all observations prior to 1985. This suggests that although injection likely occurred prior to 1985, BOEMRE did not record it. For my purposes, I therefore treat injection prior to 1985 as missing, and so I limit the data to string-months from 1985 and later for a total of 4,553,875 observations. Panel (1) of Table 4.1 lists the number of *unique* individuals at each of the levels of data described above: strings, wells, etc. For instance, there are exactly 24,386 unique wellheads present in the set of 4,553,875 string-months in the post-1984 data.

There are two variables that address injection in the OGOR-A data. I discussed one of these, "injection volume," at the beginning of this section but have only alluded

[5]The data extend through March of 2011.

[6]These observations report any of the following codes for the well status variable (described later in this section): "wellbore temporarily abandoned," "completion abandoned," or "plugged and abandoned/sidetracked." In all of these instances, the string is incapable of production.

to the second one: "well status code." This is marked as entry "16" in Figure 4.1 and "indicates the operational status of a particular well during a production month..." (Minerals Management Service (2002), page H-1). For the string-months in Panel (1) of Table 4.1, the most common codes (indicating active and idled oil and natural gas production during the month) account for over 96% of all string-months. The next most common code, reported for 76,661 string-months (or 1.68%), represents "water injection (active or inactive)."[7]

Given the two variables described above, two ways of examining injection in the OGOR-A data are apparent. Panels (2) and (3) of Table 4.1 represent each represent one of these methods. Starting with the topmost frequency in Panel (2) – there were 103,474 string-months for which the reported status was "water injection" *in at least one month* during the sample period 1/1985-3/2011. I interpret these observations as constituting the panel of 631 strings that are capable of water injection, distributed among 135 leases on 73 fields. The 131,915 observations listed in the first row of Panel (3) in 4.1 encompass the set of string-months that had positive injection volume *in at least one month* during the sample period 1/1985-3/2011. One weakness of the OGOR-A data is that the injection volume variable alone does not reveal which material is being injected, and no companion variable exists to indicate whether it is water or gas. In an attempt to ensure that the 131,915 observations do not include entries for strings that were injecting gas, I eliminated all string-months for any string that had "gas injection (active or inactive)" reported for its well status code for at least one string-month.[8] This group of string-months constitutes another panel for strings for which water injection is possible, just by different criteria. In order to distinguish the two samples, I will refer to the former (in panel (2)), in which strings

[7]Leaseholders are instructed to "[u]se this code when reporting a well that injects water into the producing formation for enhanced recovery" (Minerals Management Service (2002), page H-4).

[8]This code is reported for 17,485 observations in post-1984 sample, or 0.38%. Another weakness of these data (at least from the standpoint of examining gas injection) is that the "gas injection (active or inactive)" code does not distinguish between natural gas and carbon dioxide, the costs of which will likely differ.

were reported as injectors, as "sample 1," and the latter (in panel (3)), in which strings practiced water injection at some point, as "sample 2."

Two things are striking about 4.1. First, from the standpoint of the number of units practicing injection, water injection is rare. Slightly more than 1% of all strings ever perform any injection. This is not surprising as most strings will be devoted to oil and natural gas extraction, and as we move to subsequently higher levels in the data, the number of units with any water injection at all accounts for a slightly higher percentage of all units. Still, less than 10% of all fields (the level at which we would expect to see injection being the most common, as injection treats reservoirs, of which a field might have several) have had any water injection in the data. Second, the two criteria for identifying strings that ever water injection produce relatively different samples – specifically, barely 50% of the strings in the reported injection sample are also in the positive injection sample and just over 44% of the strings in the positive injection sample are also in the reported injection sample. Given that it is not clear which of these samples is a better representation of the water injection that occurred in the Gulf of Mexico during the sample period, I will estimate the empirical model for both.

4.4 Theory

In order to generate empirically testable implications for firms' injection behavior, I develop a theoretical model for extraction of an exhaustible resource below. I follow the lead of Amit (1986) in proposing a two-phase model, albeit the model presented here is vastly simpler. Furthermore, for the theory below regarding the second phase of production follows chapter 18 of Neher (1990) on exhaustible resource extraction with stock effects. The two phases of production correspond to primary recovery and secondary recovery.

4.4.1 Primary Recovery Phase

The operator does not control the production rate as all drive energy is provided by the reservoir. Of course, this pressure is being depleted as extraction continues – a phenomenon that is modeled by applying exponential decay to the extraction function:

$$x_t = x_0 e^{-\gamma t} \tag{4.1}$$

Letting b_t represent the amount of the deposit at t (where b_0 equals the original size of the deposit), the resource constraint implies

$$b_t = \left(b_0 - \int_0^t x_s ds\right) \geq 0 \ \forall t.$$

It turns out that the firm's only control variable is t and it only chooses a value for that control once (rather than at every point in time). The firm's problem is to optimally select a value t (denoted T_1) when it will switch to secondary recovery. Before proceeding, I make the following simplifying assumptions: the price of oil (p) is constant; the cost of primary phase production (c) is constant;[9] the interest rate (r) is constant; the firm is competitive, and the resource is homogenous and known to be available in a fixed quantity (b_0). The firm's optimization problem is:

$$\max_{T_1} V_1 + V_2^* = \int_0^{T_1} [p x_0 e^{-\gamma t} - c] e^{-rt} dt + V_2^*$$

where V_2^* is the expected payoff from the secondary recovery phase under the assumption that the optimal path of injection would be adopted, given current information.

[9] This could be labor and materials costs and the opportunity cost of productive capital in place.

4.4.2 Secondary Recovery Phase

Once the switch is made to the secondary recovery phase, the operator can control extraction via injection of water, w, into the reservoir. Thus 4.1 becomes:

$$x_t = F(w, b) \tag{4.2}$$

where extraction is increasing in both "inputs" ($F_w > 0$ and $F_b > 0$) but at diminishing rates ($F_{ww} < 0$ and $F_{bb} < 0$) and both inputs are complementary ($F_{bw} = F_{wb} > 0$). With the level of b, the amount of oil currently remaining, positively affecting extraction, there is a stock effect. As oil is removed from the reservoir due to continued extraction, a given level of extraction can only be maintained by the application of more water (i.e. with more injection).

Turning to the firm's optimization problem in the secondary recovery stage, it is:

$$\begin{aligned} \max_{w} \quad & V_2 = \int_{T_1}^{T_2} [pF(w,b) - c^w w - c] e^{-rt} dt \\ \text{s.t.} \quad & \dot{b} = -x \\ \text{and} \quad & b_0 \geq \int_{T_1}^{T_2} F(w,b) dt \end{aligned}$$

where c^w, the per unit cost of water injection, is assumed constant. Note that with the pressure maintenance provided by injection, the exponential decay factor is removed from the objective function. Before proceeding, having specified the objective function during secondary recovery, we can briefly return to the primary recovery stage to note the following:

$$T_1 = \min \left\{ \frac{1}{\gamma} \ln \left(\frac{px_0}{c} \right), \frac{1}{\gamma} \ln \left(\frac{px_0}{px_{T_1}(w^{*(t)}_{T_1}) - c_w w^{*(t)}_{T_1}} \right) \right\},$$

where $w_{T_1}^{*(t)}$ is the optimal water injection at T_1 (as determined by the firm at t when it is considering switching to secondary recovery). The first value represents the point when profits become negative from primary recovery while the second value equals the time when secondary recovery becomes more profitable than primary recovery.[10]

Turning back now to the secondary recovery problem, the present value Hamiltonian takes the form

$$H = pF(w, b) - c^w w - c + q(-F(w, b)),$$

where q is the shadow resource price. The necessary conditions for the optimal program are:

$$(p - q)F_w = c^w \tag{4.3}$$

$$\dot{q} = rq - (p - q)F_b \tag{4.4}$$

$$\dot{b} = -F(w, b). \tag{4.5}$$

4.5 Results

4.5.1 Empirical Analysis

In the earlier discussion of primary recovery, I noted that the diminution in drive energy due to oil production from a given reservoir is determined by characteristics specific to that reservoir. The shape of the drive energy profile will then determine if and when the operator will engage in an injection plan. Unfortunately, reservoir characteristics are not observed in the OGOR-A data. For this reason, I do not empirically examine the firm's decision to invest capital (drilling a well, etc.) so as to gain injection capability. I want to be confident that field unobservables are

[10] I assume that the cost of transition from primary to secondary recovery is zero. In reality, the leaseholder would likely have to drill a well. If that cost is fixed, however, the analysis is essentially unchanged.

sufficiently similar across strings – which dictated my choice of samples 1 and 2 in the previous section – so, I limit the samples to strings that are already able to inject (either because they do so in the data or the operator claims that they can).

From the theoretical model presented in the previous section for the secondary recovery phase, I propose the following reduced form empirical model:

$$\begin{aligned} vol_{im} = \beta_0 + \beta_p p_m + \beta_r r_m + \\ \beta_d \left[\frac{1}{depth_i} \right] + \beta_{pd} \left[\frac{p_m}{depth_i} \right] + \beta_{a_1} age_{im} + \beta_{a_2} \left[age_{im}^2 \right] + \varepsilon_{im} \end{aligned} \tag{4.6}$$

for string i in calendar month m.[11] The dependent variable vol_{im} is string i's volume of water injection into its reservoir during month m; p_m is the average spot price of oil for m; r_m is the annualized Treasury bill rate in m for T-bills with a 13-week maturity; $depth_i$ is the depth in feet of the well in which string i resides, and age_{im} is the number of years at m since the field to which string i belongs first produced oil or natural gas. The variables in this specification have been chosen to be consistent with the model presented in the previous section. Specifically, p_m obviously represents price in that model, while the other variables here are determinants of costs in the optimal control model.

Before proceeding to the estimation, it is useful to examine some descriptive statistics, in particular, comparing samples 1 and 2 in Tables 4.2 and 4.3[12] First, because the paper's interest lies in examining how injection volume responds to changes in the oil price, its useful to see if their is any suggestive evidence of a relationship at the aggregate level. Interestingly, the top panel of Figure 4.2 shows that water injection has not been as widespread since the mid-1990s as it was during the late 1980s and early 1990s, however, a roughly similar amount of injection (in barrels) has

[11] To be precise, the data cover all months January 1985 through March 2011.

[12] Note that on the page containing Tables 4.2 and 4.3, the top and bottom panels contain results for samples 1 and 2, respectively. This is the convention adopted for all tables and figures in the paper with the exception of Figures 4.1 and 4.2).

actually occurred. Furthermore, injection in the latter half of the time series seems to be potentially influenced by oil price. Also, I would have liked to have produced a distribution of the time from first production to first injection, in order to get a better sense of when injection first occurs. Unfortunately, injection data is apparently missing for 1984 and earlier. As an alternative, I plot kernel densities for age of string's field conditional on positive injection in the month for both samples in Figure 4.3. These suggest that water injection is largely the domain of older fields (which is consistent with the model presented earlier), for example, approximately 75% of the strings that inject in the given month are on fields that are at least 15 years old. Finally, a quick comparison of samples 1 and 2 in Tables 4.2 and 4.3 reveals them to be quite similar. The differences in variable means are all well within one standard deviation (using the variable standard deviations from either sample, as they are of similar magnitude between the samples). Aside from allowing for the comparison of the two samples, Tables 4.2 and 4.3 also reveal how infrequent water injection really is, occurring for less than 15% of the (aggregate) string-months conditional on the string being injection-capable.

Although I estimate different versions of the base specification, in discussing the regression results, I will focus on 4.6 and its full set of RHS variables. Tables 4.4 and 4.5 present pooled OLS estimates for 4.6. The results between the two samples are largely consistent with perhaps sample 2 yielding somewhat more muted effects. The results also conform to economic intuition. A one percentage point increase in the T-bill rate causes a drop of approximately 1,400 or 2,000 barrels (depending on the sample) of water injection – estimates that are consistent with water injection constituting costly investment. Furthermore, given that water injection is a response to the loss of drive energy due to sustained production *over time*, intuitively we would expect the effect on injection of an additional year of field age to be positive in later years. For samples 1 and 2, the marginal effect of an additional year of age on water injection switches from negative to positive at 52.9 and 50.8 years, respectively.

The main results relate to the price of oil. While I would like to estimate the price elasticity of injection, Tables 4.2 and 4.3 indicate how common zero values are for the injection volume, which complicates the use of a natural log transformation of the injection volume. As a very rough approximation, I compare the estimate coefficients with the samples means. For sample 1, a $1 increase in price increases water injection volume by 964 barrels, which is 9.5% of the sample mean of 10,152 barrels for the month. The analogous number for sample 2 is 647 or 7.5% of 8,584 barrels. The specification is also flexible in that the price effect can be measured for different borehole depths. Intuitively, one would expect that the deeper the well in which the water is being injected, the more costly is that injection. Graphs of the effect of price on injection are presented in Figure 4.4. As can be seen for both samples, the effect of an additional $1 on price is *increasing* in depth.

Given the fact that the same string can appear multiple times (for different months) in these data, in the estimation I cluster the standard errors on the string value. The resulting estimates and confidence intervals are graphed in Figure 4.4. With the standard errors clustered on string, the price effect is positive and significant at most depths occurring in samples 1 and 2. When I allow the error term in 4.6 to be correlated between strings on the same field (i.e. I cluster on field rather than string), however, I can no longer reject the null hypothesis that the price effect is zero.[13] In both panels of Figure 4.4, clustering on field rather than string changes the confidence intervals from the narrow band to the wider band. The wider band falls on both sides of zero, so we fail to reject the null that there is no price effect (if we believe that we are estimating the variance-covariance matrix correctly). Note that Tables 4.6 and 4.7 are the full set of analogous regression results with clustering

[13]One can imagine a scenario where injection by different strings on the same field *at the same time* was negatively correlated. Given the large number of months represented in these data for the same field, I think that caution should be exercised in embracing the results with standard errors clustered on field.

on field.

4.5.2 Discussion

While the results presented above are informative, their value might be better appreciated with some additional context. Society is not interested in water injection *per se*, but rather in how much additional oil production is induced by injection. Separating production that is marginal to injection from that which is inframarginal is a difficult task, however, so the remarks to follow will be abstract in nature.

Let ρ represent the "conversion rate" of injected barrels of water into extracted barrels of oil (over and above the level of extraction that would be achieved in the absence of injection). For simplicity, assume that it is constant.[14] Recalling that for sample 1, a \$1 increase in oil price increases water injection by an estimated 963 barrels, note that this translates to $963\rho^{-1}$ more barrels of oil produced (due to a change in injection alone) by the average string. On the flip side, a \$1 decrease in oil price decreases monthly water injection by an estimated 963 barrels meaning $963\rho^{-1}$ fewer barrels of oil produced. In the context of the royalty rate, τ_r, applied to the per barrel price of oil, p, the average decrease in oil produced per string per month would be $(\tau_r p)963\rho^{-1}$ due to the presence of the royalty on oil. Interestingly, the higher the conversion rate of water-to-oil (i.e. the more water that must be injected per each additional barrel of oil removed), the smaller is the number of "lost" barrels of oil per string and therefore the smaller is the welfare loss due to the royalty. Of course, any policy prescriptions ultimately will require a reliable estimate of ρ.

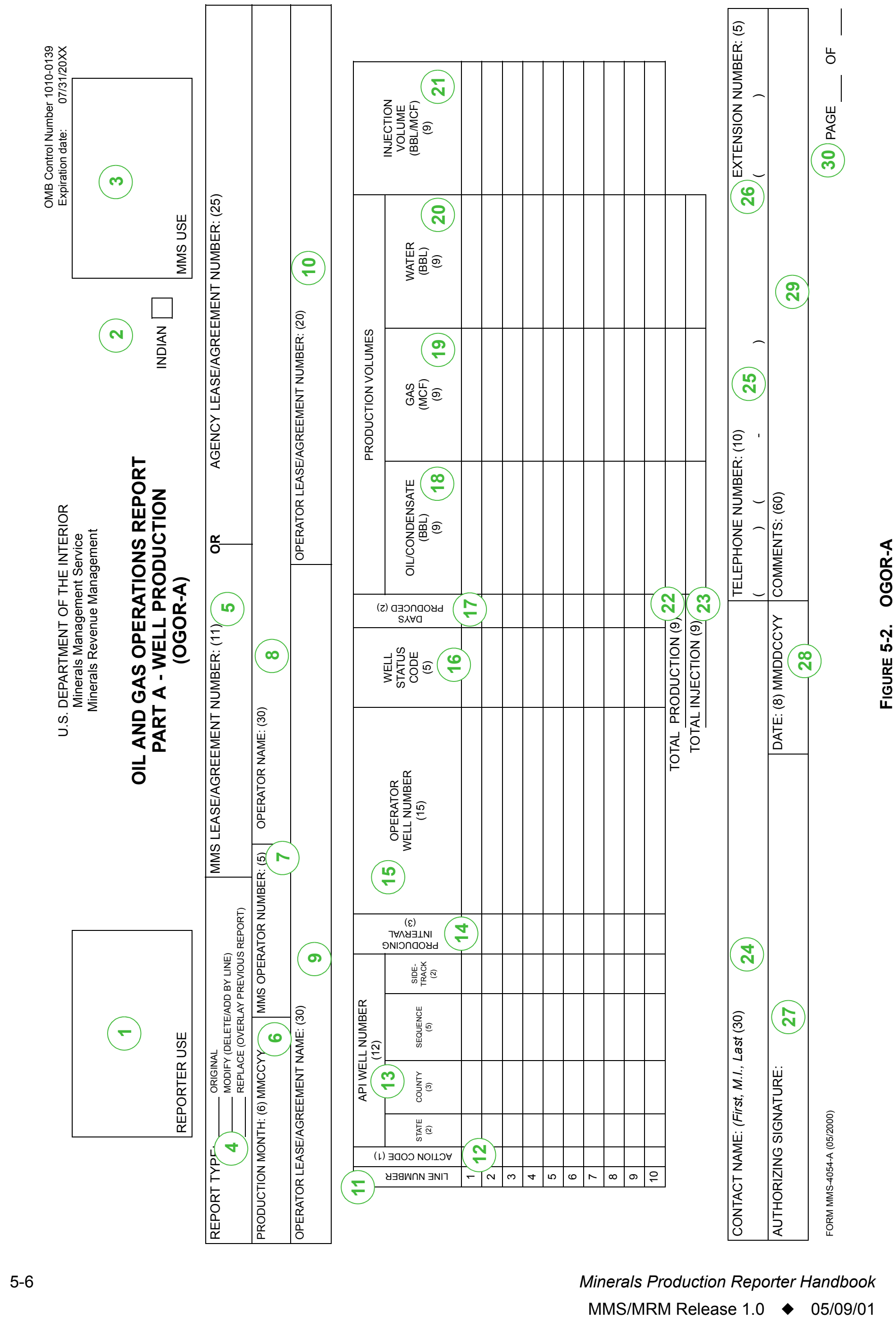
Finally, one concrete application for this research relates to the U.S. government's Strategic Petroleum Reserve (SPR), an emergency fuel store maintained by the U.S. Department of Energy. This research suggests an alternative to tapping the SPR: cutting the royalty rate for older fields where injection is happening. As we have

[14] For example, $\rho = 10$ would mean that 10 barrels of injected water are required to produce one additional extracted barrel of oil.

already seen, this will increase injection and therefore production, though the size of the production increase will depend on ρ. If ρ is large and there are very few producing strings, however, this targeted suspension of the royalty will likely not produce a sufficiently large quantitative response in total production.

4.6 Conclusion

I estimate that a \$1 increase in monthly average oil price leads to a 647 to 964 barrel increase in water injection. Although an elasticity might be the preferred parameter to a marginal effect from the standpoint of policymakers, the fact that monthly injection volume is zero for never less than 85% of the sample complicates its estimation. Nonetheless, because the presence of the royalty mimics an oil price increase, these estimates carry important implications for the design of optimal leasing policy (particularly with regard to the royalty) for fields that no longer are in the primary recovery phase. The royalty's indirect effect on production via its direct effect on injection represents a less obvious source of welfare loss, and one that can be quantified through further research.


OMB Control Number 1010-0139
Expiration date: 07/31/20XX

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Minerals Revenue Management

OIL AND GAS OPERATIONS REPORT
PART A - WELL PRODUCTION
(OGOR-A)

REPORTER USE

INDIAN

MMS USE

REPORT TYPE: ORIGINAL / MODIFY (DELETE/ADD BY LINE) / REPLACE (OVERLAY PREVIOUS REPORT)

MMS LEASE/AGREEMENT NUMBER: (11) OR AGENCY LEASE/AGREEMENT NUMBER: (25)

PRODUCTION MONTH: (6) MMCCYY

MMS OPERATOR NUMBER: (5)

OPERATOR NAME: (30)

OPERATOR LEASE/AGREEMENT NAME: (30)

OPERATOR LEASE/AGREEMENT NUMBER: (20)

LINE NUMBER	ACTION CODE (1)	API WELL NUMBER (12) STATE (2)	COUNTY (3)	SEQUENCE (5)	SIDE-TRACK (2)	PRODUCING INTERVAL (3)	OPERATOR WELL NUMBER (15)	WELL STATUS CODE (5)	DAYS PRODUCED (2)	PRODUCTION VOLUMES OIL/CONDENSATE (BBL) (9)	GAS (MCF) (9)	WATER (BBL) (9)	INJECTION VOLUME (BBL/MCF) (9)
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													

TOTAL PRODUCTION (9)
TOTAL INJECTION (9)

CONTACT NAME: (*First, M.I., Last* (30)

TELEPHONE NUMBER: (10) ( ) (-)

EXTENSION NUMBER: (5) ( )

AUTHORIZING SIGNATURE:

DATE: (8) MMDDCCYY

COMMENTS: (60)

PAGE ___ OF ___

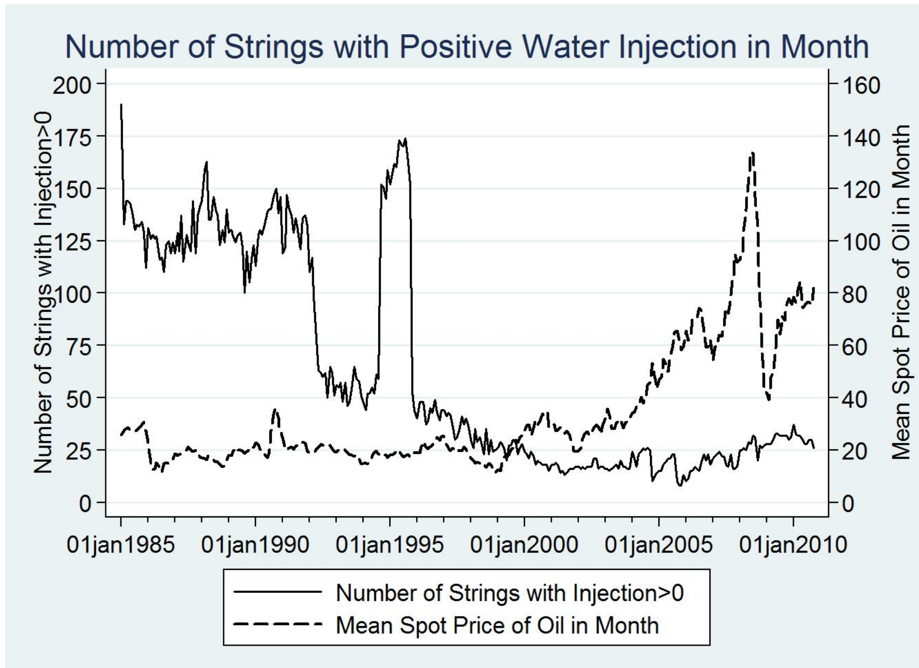
FORM MMS-4054-A (05/2000)

FIGURE 5-2. OGOR-A

5-6

Minerals Production Reporter Handbook
MMS/MRM Release 1.0 ◆ 05/09/01

Figure 4.1: OGOR-A Form.



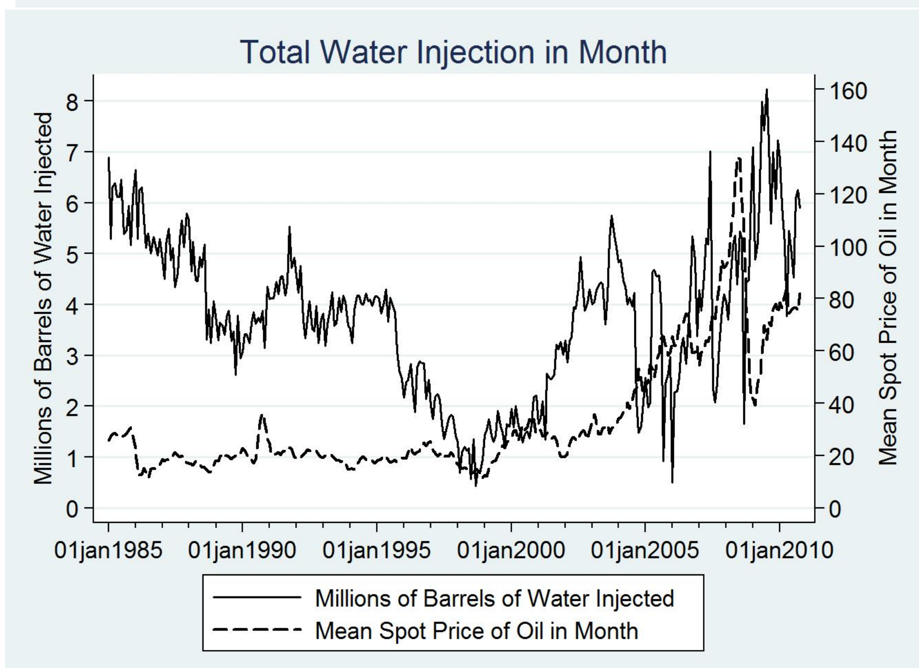
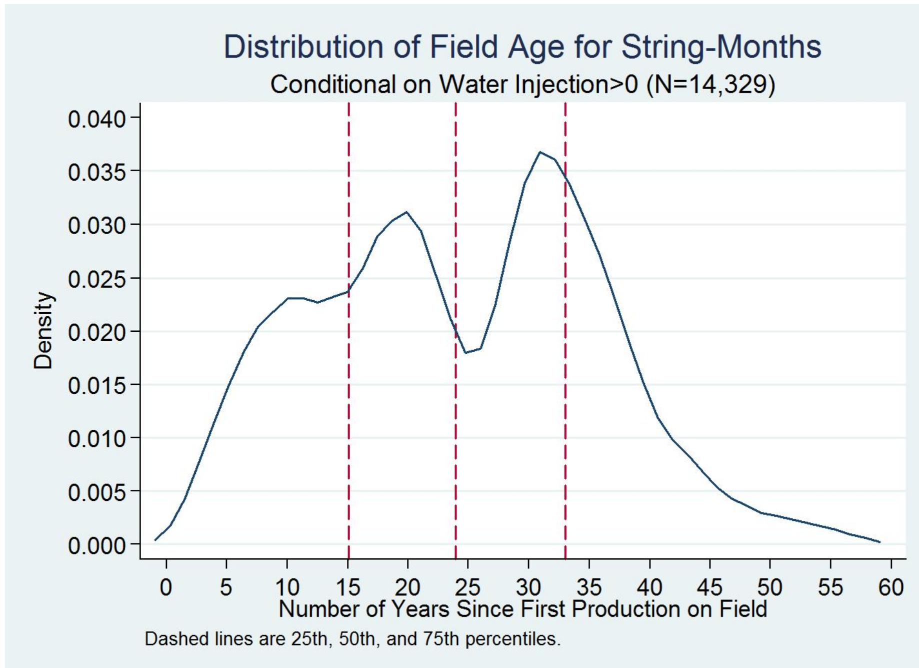


Figure 4.2: Water injection in U.S. Gulf of Mexico, 1985-2010.



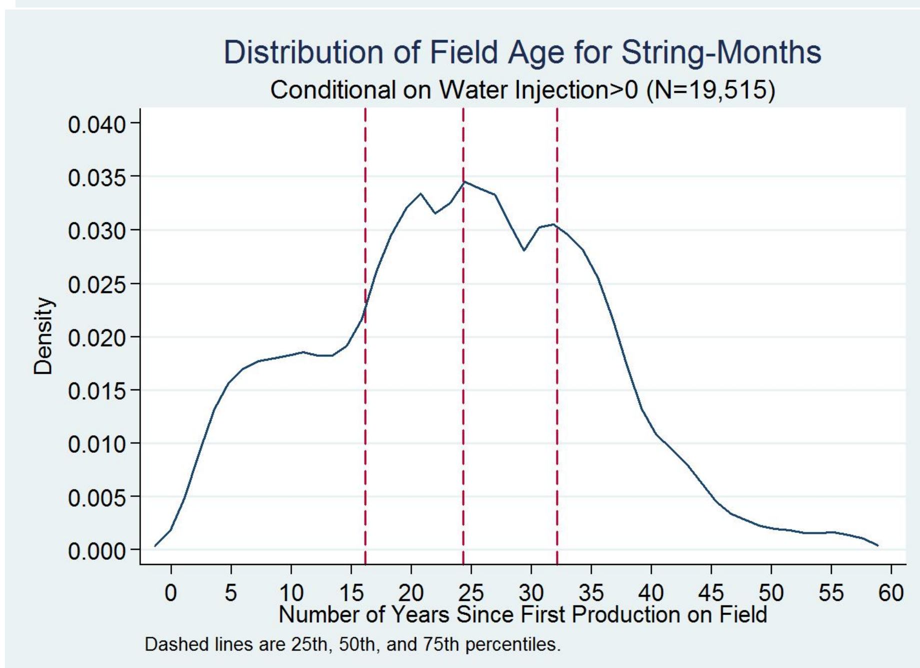
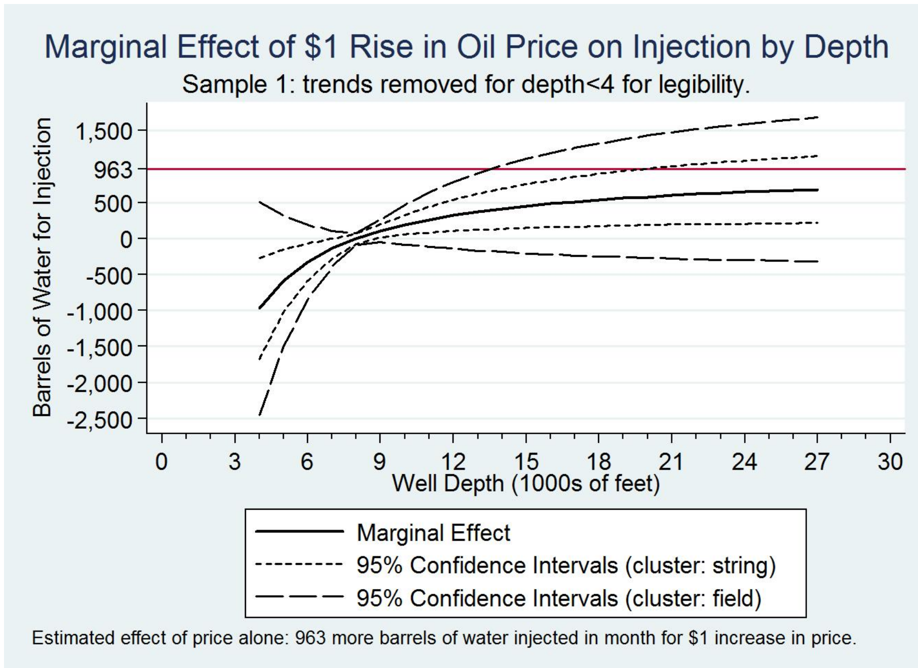


Figure 4.3: Field age at month of water injection for samples 1 and 2.



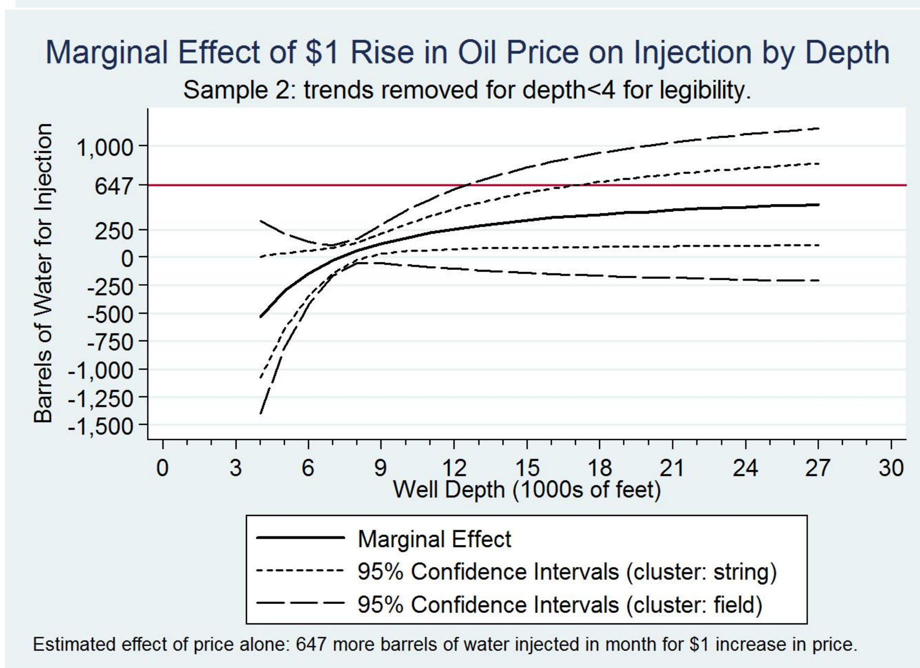


Figure 4.4: Marginal effects of oil price by well depth.

	(1) Total	(2) H_2O Injector		(3) H_2O Injection>0		(4)
	N	N_1	% of Total	N_2	% of Total	$N_1 \cap N_2$
string-months	4,553,875	103,474	2.27	131,915	2.90	58,551
strings	56,474	631	1.12	763	1.35	317
wells	28,763	557	1.94	705	2.45	301
wellheads	24,386	544	2.23	689	2.83	94
leases	5,120	135	2.64	169	3.30	93
fields	1,357	73	5.38	95	7.00	51

Table 4.1: Frequencies by data level in OGOR-A.

	Mean	Std. Deviation	Minimum	Maximum
Injection Volume	10,152	51,998	0	2,318,843
Injection Indicator	0.1380	0.3449	0	1
Oil Price	29.85	20.91	11.31	134.02
Interest Rate	4.64	2.14	0.03	8.82
Depth^{-1} (Well)	0.0105	0.0031	0.0037	0.0375
Oil Price$\times\text{Depth}^{-1}$	0.3113	0.2402	0.0542	3.14
Age (Field)	31.53	11.56	0	61.9
Age^2	1,128	712.56	0	3,831
N		102,670		

Note: depth measured in 100's of feet and age measured in years.

Table 4.2: Descriptive statistics for sample 1.

	Mean	Std. Deviation	Minimum	Maximum
Injection Volume	8,584	48,684	0	2,318,843
Injection Indicator	0.1479	0.3550	0	1
Oil Price	30.19	21.24	11.31	134.02
Interest Rate	4.53	2.12	0.03	8.82
Depth^{-1} (Well)	0.0108	0.0035	0.0037	0.05
Oil Price$\times\text{Depth}^{-1}$	0.3261	0.2643	0.0542	6.70
Age (Field)	27.94	11.88	0	62.9
Age^2	922	689.18	0	3,956
N		130,742		

Note: depth measured in 100's of feet and age measured in years.

Table 4.3: Descriptive statistics for sample 2.

	(1)	(2)	(3)	(4)
Oil Price	119.7*	1,175***	147.04*	963.5**
	(2.20)	(3.32)	(2.44)	(2.87)
Interest Rate	-759	-768	-1,771**	-1,958***
	(-1.61)	(-1.66)	(-3.06)	(-3.32)
Depth^{-1} (Well)		1,033,596		-75,763
		(1.57)		(-0.11)
Oil Price$\times$$\text{Depth}^{-1}$		-103,376***		-77,461**
		(-3.37)		(-2.81)
Age (Field)			-3,416***	-2,867***
			(-5.68)	(-5.13)
Age^2			37.3***	27.1***
			(4.87)	(3.50)
Constant	10,095***	-38.51	79,588***	75,163***
	(3.58)	(-0.00)	(6.03)	(4.86)
N	102,670	102,670	102,670	102,670
R^2	0.0047	0.0353	0.0853	0.1133

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

Table 4.4: Estimates for sample 1 – SE's clustered on string.

	(1)	(2)	(3)	(4)
Oil Price	81.9	636.5*	147.4**	647.4*
	(1.90)	(2.25)	(2.77)	(2.45)
Interest Rate	-322.9	-362.8	-1,426*	-1,390*
	(-0.84)	(-0.95)	(-2.58)	(-2.58)
Depth^{-1} (Well)		139,620		200,981
		(0.35)		(0.55)
Oil Price$\times$$\text{Depth}^{-1}$		-52,106*		-47,316*
		(-2.12)		(-2.21)
Age (Field)			-1,693***	-1,576***
			(-4.62)	(-4.07)
Age^2			16.73***	15.50**
			(3.69)	(2.81)
Constant	7,573**	6,495	42,475***	38,330***
	(3.13)	(1.20)	(4.97)	(4.17)
N	130,742	130,742	130,742	130,742
R^2	0.0019	0.0208	0.0350	0.0494

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

Table 4.5: Estimates for sample 2 – SE's clustered on string.

	(1)	(2)	(3)	(4)
Oil Price	119.8	1,176	147.2	964
	(1.08)	(1.43)	(1.23)	(1.35)
Interest Rate	-758.3	-767.5	-1,770	-1,957
	(-0.76)	(-0.78)	(-1.39)	(-1.53)
Depth^{-1} (Well)		1,033,893		-75,526
		(0.87)		(-0.07)
Oil Price$\times$$\text{Depth}^{-1}$		-103,394		-77,493
		(-1.48)		(-1.33)
Age (Field)			-3,417**	-2,868**
			(-2.95)	(-2.99)
Age^2			37.3**	27.2*
			(2.67)	(2.18)
Constant	10,092*	-45.8	79,604**	75,178**
	(2.01)	(-0.00)	(2.98)	(2.81)
N	102,666	102,666	102,666	102,666
R^2	0.0047	0.0353	0.0853	0.1134

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

Table 4.6: Estimates for sample 1 – SE's clustered on field.

	(1)	(2)	(3)	(4)
Oil Price	81.9	636.5	147.4	647.4
	(0.99)	(1.27)	(1.33)	(1.36)
Interest Rate	-322.9	-362.8	-1,426	-1,390
	(-0.44)	(-0.49)	(-1.21)	(-1.24)
Depth^{-1} (Well)		139,620		200,981
		(0.22)		(0.32)
Oil Price$\times$$\text{Depth}^{-1}$		-52,106		-47,316
		(-1.27)		(-1.31)
Age (Field)			-1,693*	-1,576*
			(-2.18)	(-2.06)
Age^2			16.7	15.5
			(1.83)	(1.55)
Constant	7,574*	6,495	42,475*	38,330*
	(2.19)	(0.90)	(2.36)	(2.35)
N	130,742	130,742	130,742	130,742
R^2	0.0019	0.0208	0.0350	0.0494

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

Table 4.7: Estimates for sample 2 – SE's clustered on field.

CHAPTER V

Conclusion

Offshore sources, in both shallow and deep waters, are increasingly important contributors to global oil and natural gas production. Furthermore, given that these sources exist in the territorial waters of national governments, it is these governments that will have tremendous influence over how these resources reach the market, if at all. For example, two basic elements of any nation's hydrocarbon leasing program – the royalty rates levied on production in exchange for mineral rights and the geographic dimensions of a leased unit – have potentially important welfare implications (as examined in chapters 1 and 2, respectively). Obviously, understanding the efficiency characteristics of an existing policy is essential for informing policymakers about where such a policy might be improved. In this dissertation, I have applied both theoretical and empirical models to oil and gas leasing microdata collected by the U.S. federal government for the Gulf of Mexico in order to better understand issues of public economics within offshore hydrocarbon investment and production.

In Chapter 1, using variation in royalty rates introduced by a policy called the Deep Water Royalty Relief Act (DWRRA), I find that the potential for a royalty payments waiver: (1) increases the probability that an individual tract is acquired by an average of 193% (a mean increase of 5.6 percentage points); (2) decreases the probability that a lease is ever drilled during its observed lease term by an average of 14.5% (a mean decrease of 1.3 percentage points); and (3) increases the expected number of explored leases by 150%. The introduction of DWRRA also increases the average winning bid per lease by 60%. One potential implication for policy: if the revenue lost due to a royalty waiver is largely offset by increases in the winning bids, then this modified contract structure improves welfare without completely surrendering revenue (because the profit-sharing disincentive is removed, at least in some circumstances).

In Chapter 2, I estimate the implied value of information spillovers in oil and natural gas exploration via an event study design. Examining cumulative unpredicted daily stock returns for firms owning leases adjacent to a lease where a hydrocarbon discovery occurs during the trading days immediately preceding and following that discovery, I interpret the accumulated returns as the value of new information. A potential implication of this research is that if information externalities are large in value relative to the cost of exploratory drilling, then the amount of exploration is below the welfare-maximizing level as prospective explorers do not take into account the high value of information that their activity could generate for their neighbors. The results imply that this is the case: firms that own leases adjacent to the discovery lease (but not the discovery lease, itself) realize an average abnormal return that translates to $315 million in market capitalization (an effect which is quantitatively large compared to average costs for drilling an exploratory well).

In Chapter 3, I measure how oil price affects water injection, a method for prolonging the productive lifetime of oil fields. I find that a $1 rise in price increases the water injected into the well's reservoir by approximately 650 to 950 barrels, equalling 7.5 to 9.5% of the mean monthly injection volume (depending on the sample chosen). Equating the estimated price effect with a potential tax effect, this finding has implications for how the government levies a royalty on mature oil fields for which operators invest in pressure maintenance.

The findings in this dissertation have implications for the structure of oil and natural gas leasing in the U.S. and elsewhere. With reserves of "easy" oil from conventional onshore fields ever dwindling, the importance of hydrocarbons derived from remote and technically-challenging sources, deep water in particular, will continue to grow. So too, will the need for sound policy that maximizes the social value of such scarce resources.

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