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Essays on Energy Economics:

Markets, Investment and Production

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Essays on Energy Economics:

Markets, Investment and Production

by

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Dedication

To my devoted wife **Maryam**,

for her endless love, patience, support, and encouragement;

To my lovely daughter **Hoda**, a blessing in our lives.

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Essays on Energy Economics:

Markets, Investment and Production

Mohammad Morovati Sharifabadi, Ph.D.

The University of Texas at Austin, 2013

Supervisor: Sheridan Titman

My dissertation consists of three distinct but related chapters on Energy Economics and Finance.

My first chapter is an empirical evaluation of market conduct in global crude oil markets. "Hotelling rule" states that even in competitive equilibrium, price of an "exhaustible resource" exceeds its marginal cost due to the opportunity cost of depleting the non-renewable resource. This cost is called "scarcity rent". Oil price exceeds its marginal extraction cost significantly. This can be attributed to two different sources: effect of scarcity of oil on prices or exercising market power by OPEC (collusion). In this paper, I use Porter (1983) approach considering the possibility of "scarcity rent" component involved in the gap between price and marginal extraction cost in the oil market. The novelty of my approach is to empirically estimate scarcity rent using data on cost of production of oil. Two benchmark cases, where scarcity rent is either zero (non-exhaustible resources hypothesis (Adelman 1990)) or equal to minimum price-cost margin are considered. The results show that in both cases OPEC failed to

cooperate effectively and in second case, market conduct estimated is closer to Cournot behavior.

In the second chapter of my dissertation, we employ a real options approach to evaluate oil and gas companies' investment decisions in an empirical setup. We develop a theoretical model to derive testable predictions. A unique measure of investment costs is obtained from energy industry data vendors. This novel dataset contains details of contract terms and pricing for offshore drilling equipment, which constitute the major share of investment costs in offshore oil field development. The investment database is combined with financial and macroeconomic data, which enables us to perform a panel data analysis of investments' response to variations in investment costs and market variables such as the slope of futures curve, firms' past earnings, cost of capital and implied oil price volatility. Our results show that the larger firms, facing less financial friction, are more forward looking while the smaller firms, who have less access to capital markets, are more dependent on their past earnings.

The third chapter of my dissertation is about the effect of recent natural gas production boom on U.S. manufacturing. Natural gas production in North America has increased significantly over the past decade causing the prices to plunge during past 5 years. The purpose of this research is to investigate the effect of low natural gas prices on energy intensive U.S. manufacturing industries using market data. I empirically evaluate the stock market reactions of publicly traded companies in energy intensive industries to arrival of new information about the unexpected price shocks in natural gas futures markets. My results show that the stock market does not react significantly to innovations in the expected price of natural gas, proxied for by monthly changes in natural gas futures contracts with a fixed maturity date. I then split the sample into two groups based on their expenditure on natural gas as a ratio of their total production value. The stock market valuation of companies in high “natural gas intensity” industries were positively affected by unexpected downward shocks in natural gas prices and the results are significant.

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Chapter 1: Are Markups in the Crude Oil Market Caused by Exhaustibility or OPEC Market Power? An Empirical Test

1.1. INTRODUCTION

The goal of this chapter of my dissertation is to test whether the margin between price and the marginal extraction costs observed in the oil market is caused by exhaustibility of oil or by OPEC market power. I propose a dynamic model for the oil market and empirically test for OPEC market power during 1986-2006 period. My estimation approach would be similar to Porter (1983) except that I account for exhaustibility of oil and its effect on producers' optimization problem. The rest of introduction will be consisted of OPEC background and brief discussion of related literature on identifying collusion in the oil market. In section 2 I will propose the theoretical model and how I will deal with difficulties raised by exhaustibility issue. Section 3 describes the data used in the estimation procedure. Section 4 describes the estimation procedure and results. Section 5 concludes and suggests further extensions.

According to OPEC official website, "The Organization of the Petroleum Exporting Countries (OPEC) is a permanent, intergovernmental Organization, created at the Baghdad Conference in September 1960, by Iran, Iraq, Kuwait, Saudi Arabia (major crude oil producers in Middle East) and Venezuela. Nine other members joined later in 1960's." According to BP Statistical review 2013, OPEC countries account for 43% of oil production and they own 73% of oil reserves today. OPEC is a classic textbook example of collusion. Although it seems to have a large market power, many researchers have argued that OPEC countries in fact lack a commitment device to coordinate their actions. They conclude that the price volatilities observed in the market are caused by other factors such as major supply or demand shocks and exhaustibility effect of crude oil rather than collusion and price wars among cartel members. (Cremer, Salehi (1991)).

James Griffin (1985) tests several alternative hypotheses about the oil market and OPEC behavior. In each case he considers a static optimization problem and tries to test the hypotheses. These hypotheses include cartel models, competitive market, revenue targeting etc. In cartel model he tests whether the observed price can be a result of collusive behavior or not. In competitive model he tests MacAvoy’s (1982) suggestion that the price of oil is determined mainly according to market fundamentals such as supply and demand interaction in a competitive market rather than collusion among the oil market players. The revenue targeting case is about the assumption that Oil producing countries have target revenue goals. This assumption is justified in an imperfect international capital market so the oil producing countries cannot borrow or lend in periods of excess or shortage of oil revenue.

Griffin derives a model for any of the cases described above and tests using the quarterly data from 1971 to 1983. The results of empirical tests are that the cartel model is not rejected for 7 major OPEC countries while other models are rejected.

Spilimbergo (2001) uses a similar approach to Griffin but uses a dynamic model for the competitive case. In this case an oil producing country solves an optimization problem of extracting an exhaustible resource. As studied in Pindyck (1978). He considers a dynamic optimization of an agent in a competitive market of an exhaustible resource and tests the hypotheses of a competitive market against a cartel assumption of

Griffin. He uses the quarterly data from 1983-1991. He finds that the hypothesis of cartel is rejected for all the countries except Saudi Arabia.

Hotelling (1931) is one of the most influential prices of literature in natural resource economics which investigates the exhaustibility of resources. His main result, mostly referred to as “Hotelling rule”, states that given a zero marginal extraction cost and fixed amount of resource and in absence of substitute goods, there is an implicit opportunity cost associated with depleting an exhaustible resource due to its being non-renewable. The owner of a natural resource should be indifferent between selling the resource today or keeping the resource and selling it next period. As a result, the price of an exhaustible resource must grow at a rate equal to the rate of interest both along a monopolistic extraction path and the competitive resource industry.[1] However, price of exhaustible resources seem to be random walk rather than growing. This may be caused by different several different sources. First of all, changes in extraction costs may affect the prices. Secondly, the possibility of discovering a substitute may decrease the opportunity cost of depleting the resource and uncertainty about actual size of the stock of exhaustible resource may affect scarcity rent because in case another stock of resource is discovered, the current oil field may be considered less exhaustible than before (see Farzin (1992) and Just, et al (2005)). Litzenberger and Rabinowitz (1995) also provide an explanation as to why normal backwardation in oil futures contracts is important to encourage extraction of crude oil from reserves.

[1] See Devarajan and Fisher 1981

Porter (1983) studies cartel stability in a homogenous goods market (railroad transportation) among Joint Executive Committee members. To identify the collusive and non-collusive periods he uses an application of Green and Porter (1984) theoretical model. Firms' profit functions are time separable so each firm solves a static problem in each period except considering the possibility of collusion and possible benefit of not deviating from collusive behavior. In an exhaustible resource case, each firm's optimization problem inherently bears a dynamic aspect due to exhaustibility of the resource. Porter then derives a FOC depending on market conduct:

$$p_t\left(1+\frac{\theta_t}{\alpha_1}\right) = DQ_t^{\delta-1} \qquad (1.1)$$

In which p_t is price at period t, α_1 is price elasticity of demand, D is a function of specific parameters and Q_t is quantity supplied to the market. θ takes values 1, $\sum s_{it}^2$ or 0 in collusive, Cournot and perfect competition, respectively. He uses a switching regressions approach proposed by Kiefer (1980) and finds model parameters including market conduct using maximum likelihood estimation. He also identifies collusive periods from non-collusive ones in an iterative process: taking an initial guess for collusion dummy variables, calculating model parameter values, taking these values as given calculating collusion probabilities in each period and updating the parameter estimates and continuing this process until convergence. Porter (1983) provides a novel framework for studying cartel stability however one should be careful about the assumptions and the nature of the market. For example, in transportation cost, there are some close substitutes available which are not present in the oil market. Also the exhaustibility of oil would cause a positive margin between extraction cost and price even in a perfectly competitive market (for a confusion of marginal extraction cost and marginal total cost see Almoguera and Herrera (2007))

Almoguera and Herrera (2007) apply Porter (1983) approach to the oil market using quarterly data from 1974-2004. They use the same functional form assumptions as Porter (1983) about the oil market. Their estimation result shows that the oil market was more in a Cournot competition rather than collusion especially in last 20 years. Although they derive reasonable results, they do not consider the intrinsic differences between oil and railroad transportation. First of all, they do not enter the exhaustibility of oil into their optimization problem. Second problem with their approach is that their demand function specification is exactly like Porter's specification for railroad transportation which does not seem to be necessarily true for the oil market. In contrast, the literature on oil demand estimation uses another specification which is described in section 1.2. This specification might be problematic because they do not consider that there is no good substitute for oil so its demand is pretty persistent in short-run. Many researchers include lagged consumption as a measure of infrastructure installed which depend on oil consumption like power plants, cars, factories etc in estimation of oil demand. The result of their estimation for price elasticity is relatively high rather than other estimates in literature. (See Gately and Huntington (2002) and Cooper (2003))

The rest of this paper is organized as follows. Section 2 is dedicated to discussion of the theoretical model and effect of exhaustibility on the optimization decision of oil producers as well as the industrial organization of the oil market. I describe the data I use for empirical strategy in section 3. Estimation results are presented in section 4. In section 5 I discuss potential extensions and conclude the paper.

1.2. MODEL

1.2.1 Optimization Problem

Demand function estimations are derived from Gately and Huntington (2002) with the following specification:

$$\log Q_t = \alpha_0 + \alpha_1 \log p_t + \alpha_2 g_t + \alpha_3 \log Q_{t-1} + U_{1t} \qquad (1.2)$$

where p_t denotes crude oil price in period t, Q_t denotes total quantity of crude oil consumed in period t, g_t denotes growth in world real GDP and U_{1t} is error term which is assumed to be iid normal across periods.[2] Including lagged value of consumption is widely accepted in estimation of demand for oil because this variable incorporates the fact that there is not a good substitute for oil, at least in the short run, so the demand is expected to be relatively persistent in consequent periods.[3] Alternative specifications are assessed but the coefficient results are virtually not changed.

I assume a simple differentiable convex extraction cost function for tractability of model. Although this function cannot perfectly describe production behavior in long run, it can serve as a good approximation in the short run. However, due to huge

[2] I have tested equation (1.2) for serial correlation among error terms and the hypothesis for $\alpha_3 = 0$ was rejected (with a t-statistic=49) and the corresponding Durbin-Watson d-statistic is 1.929 which in fact shows that assuming no serial correlation is reasonable.

[3] Furthermore, price elasticity of demand for oil is asymmetric but for simplicity I will assume a simpler specification similar to third approach in Gately and Huntington (2002).

variability of extraction costs[4] across different regions and oil fields, I assume that cost functions are producer specific:

$$C_i(q_{it}) = a_i q_{it}^{\delta} + c_0 \qquad (1.3)$$

where $\delta > 1$ so that extraction of an extra unit of oil becomes more and more costly as extraction rate increases.[5]

In order to incorporate exhaustibility of oil, I will consider the simplest case for the moment[6] where each producer exactly know S_0, total oil reserves at time 0, extraction cost function $C(q_{it})$, is only a function of amount produced q_{it}, at each time period t, hence does not change over time, and producers have perfect foresight about prices.[7] I will assume a competitive fringe (Non-OPEC producers) and a potentially collusive section (OPEC) in the market. Each producer solves the following problem:

$$\max_{q_{it}} \{\sum_{t=0}^{\infty} \beta^t \big(p_t q_{it} - C_i(q_{it})\big) \qquad \text{profit maximization problem} \;\; (1.4)$$

subject to exhaustibility of the total oil reserves she owns:

$$\sum q_{it} \leq S_0 \qquad \text{exhaustibility constraint} \;\; (1.5)$$

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[4] According to Energy Information Administration, extraction of a barrel of oil using water injection in deep oil wells in west Texas would cost $45 in 2006 while in some oil wells in other parts of world it cost less than $5.

[5] Considering technical issues regarding life cycle of oil wells, there is an optimal maximum extraction rate from any specific oil well so extracting more than that rate destroys the oil well so in fact costs more to producer. Slower extraction rates will not harm the well but may not be economically viable.

[6] It is important to notice that the uncertainties about the total reserves and new technological innovations will challenge these assumptions. Hence, I will relax some of these assumptions later, especially the one about fixed stock of exhaustible resource, which will have important implications for scarcity rent estimation as discussed in section 1.2.3.

[7]The assumption about perfect foresight about future prices is strong and will be relaxed later. Nonetheless, the existence of widely traded oil futures contracts reveals information to the producers regarding the expected future movements of oil prices given all available information at each point of time.

Using Lagrange multiplier λ for the exhaustibility constraint, one can derive the first order necessary condition (FONC) as follows:

$$\beta^t(p_t + \frac{q_t \partial p_t}{\partial q_t} - C_i{}'(q_{it})) = \lambda \qquad \text{FONC (1.6)}$$

Rewriting the FONC using $\beta = \frac{1}{1+r}$ we can derive:

$$p_t + \frac{q_t \partial p_t}{\partial q_t} - C_i{}'(q_{it}) = \lambda(1+r)^t \qquad (1.7)$$

Equation (1.7) has important implications: First notice that in a competitive market, where change in quantity of a single producer would not affect the market price, equation (1.7) reduces to a version of Hotelling rule which states that the price-cost margin of an exhaustible resource will increase exponentially over time with the interest rate:

$$p_t - C'(q_{it}) = \lambda(1+r)^t \;\Rightarrow \frac{p_{t+1-C'_i(q_{it+1})}}{p_t - C_i'(q_{it})} = (1+r) \qquad \text{Hotelling Rule (1.8)}$$

Second, given our demand specification in Equation (1.2), price elasticity of demand is α_1 so we can rewrite Equation (1.7) to derive:

$$p_t + \frac{q_t \partial p_t}{\partial q_t} - C_i{}'(q_{it}) = \lambda(1+r)^t \Rightarrow\; p_t + \frac{q_t \partial p_t}{\partial Q_t}\frac{\partial Q_t}{\partial q_t} = C_i{}'(q_{it}) + \lambda(1+r)^t$$

$$\Rightarrow\; p_t + \frac{q_t p_t}{\alpha_1 Q_t}\,\frac{\partial Q_t}{\partial q_t} = C_i{}'(q_{it}) + \lambda(1+r)^t$$

$$\Rightarrow\; p_t + \frac{p_t\, s_{it}}{\alpha_1}\,\frac{\partial Q_t}{\partial q_t} = C_i{}'(q_{it}) + \lambda(1+r)^t$$

$$\Rightarrow p_t\left(1 + \frac{\theta_{it}}{\alpha_1}\right) = C_i'(q_{it}) + \lambda(1+r)^t \qquad \text{Market structure equation (1.9)}$$

where θ_{it} is the elasticity of total output w.r.t firms own output. This will be equal to zero, 1 or $s_{it} = \frac{q_{it}}{Q_{it}}$ respectively in perfectly competitive, collusive or Cournot competition cases.[8] It can be shown that given specification of demand and cost functions, market shares are constant over time. Multiplying both sides of equation (8) with market shares and summing over all producers, world oil supply equation can be derived:

$$p_t\left(1+\frac{\theta_t}{\alpha_1}\right) = DQ_t^{\delta-1} + \lambda(1+r)^t \qquad \text{Market structure equation } (1.9')$$

where $D = \delta\left(\sum_i a_i^{\frac{1}{1-\delta}}\right)^{1-\delta}$ and $\theta_t = \sum_i s_{it}\theta_{it}$.

Porter (1983) derives a similar equation but without a scarcity rent term: $\lambda(1+r)^t$. He then proceeds by taking logs and hence deriving a log linear supply function. Note that I can not apply the same approach because there exists an extra additive term that would not come out of logarithm function. Using exact Porter approach one cannot estimate all the parameters and they would not be identified. I will try to get around this problem by finding a proxy for scarcity rent in a way that I can estimate the above model.

1.2.2. Scarcity Rent Problem

If information on marginal extraction cost in a competitive market were available, we would be able to take margin between price and marginal extraction cost as scarcity rent. Although the oil market is relatively concentrated, it also has a

[8] For a detailed discussion of different market conducts and calculation steps for the market conduct index in the oil markets see: Almoguera and Herrera (2007)

competitive fringe. I will estimate scarcity rent in each period by looking at active oil wells with highest production costs and take the margin between these costs and oil price as scarcity rent. The rationale for this approach is that the most costly wells are just indifferent between producing and not producing considering all costs including scarcity rent. By taking these observations on highest cost producing wells I am in fact looking at last entrant in the market and since these last entrants will be close to break even point,[9] their marginal revenue of extracting one barrel of oil (price) should equal their marginal total cost which is consisted of marginal extraction cost plus the scarcity rent:

$$SR_t + Marginal\ extraction\ cost = marginal\ total\ cost \leq price$$

For the last entrant, the inequality above should bind. This margin will serve as a measure for scarcity rent. Of course there are lower cost producers in the market but their price-cost margin would be the scarcity rent plus some cost advantage in production.[10]

Looking at the data about this margin, it seems to be almost a constant fraction of oil price in each period. The ratio of price-cost margin to oil price,k, for these wells is estimated[11] to be 0.2377 with R-squared ratio of 0.84 so I will employ this estimation and insert it into the Equation(8) to derive the following equation:

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[9] I am in fact assuming low entry and exit costs for these last entrants which is reasonable considering the nature of small producers that are analyzed here.

[10] Note that the assumptions behind this argument is that First, the oil produced in different wells is almost homogenous which is not a very strong assumption specifically because the minor differences in quality of different oil types is offset by minor differences in their prices. Second assumption is that scarcity rent for different types of oil is almost the same which given the previous assumption about homogeneity, and noting that scarcity rent is in fact the opportunity cost of selling oil today rather than keeping it to the next period, is again not a very strong assumption.

[11] For detailed estimation process refer to section 1.3.

$$p_t\left(1+\frac{\theta_t}{\alpha_1}\right) = DQ_t^{\delta-1} + kp_t$$

$$p_t\left(1+\frac{\theta_t}{\alpha_1} - k\right) = DQ_t^{\delta-1} \qquad \text{Simplified Market structure equation (1.10)}$$

1.2.3. Further Notes on Estimating Scarcity Rent

"Scarcity rent" refers to opportunity cost of selling a unit of exhaustible resource today rather than keeping it to the next period and selling it then. As a result, in a perfect competition case, price of an exhaustible resource would be equal to its "user cost" which equals marginal extraction cost plus scarcity rent. If our simplifying assumptions about extraction of an exhaustible resource at the beginning of section 2 were not too strong then the Hotelling rule would predict that this scarcity rent would exponentially increase. However, there are some issues that challenge Hotelling rule. First, there is a lot of uncertainty about the probable amount of oil in earth. As a clarifying example, assume that an extraordinarily huge oil field, comparable to total proved reserves, is discovered today. As a result of this discovery, the exhaustibility of oil becomes less relevant so scarcity rent would decrease.[12] On the other hand, expectations of future prices play a crucial role on the "opportunity cost" of selling a resource today. This is because if for any reason owners of the exhaustible resource believe that next period's price will fall (due to an innovative backstop technology or low economic growth), then the opportunity cost of selling the resource today will decline. All mentioned above

[12] For example, coal is sometimes assumed to be non-exhaustible because at current consumption rates it will last for more than 3000 years so in fact there is not much exhaustibility rent associated with coal. For more discussion see Khanna (2003)

make it difficult to derive a straightforward estimate for scarcity rent.[13] However, looking at data as described in section 3 we could infer that due to contribution of all different sources to scarcity rent, empirically we observe a constant ratio of price to be an upper bound for scarcity rent so I will employ that estimate.

Legal contracts on royalties paid to the owner of a natural resource could also be a candidate for estimating of scarcity rent but there are 2 problems: First, Legal contracts on oil fields are usually long term which do not reflect changes in scarcity rent in short term.[14] Second issue could be observed especially when the price of oil declines and as a result previously operative oil wells become inactive although according to their contracts the royalty rate is a fixed portion of the production revenue which is in fact not realized (because revenue of the oil well is zero in inactive periods.)

1.2.4. Identifying Collusion

Given the above functional form assumptions, the estimation process is similar to that of Porter (1983). Suppose $\{I_t\}$ is a sequence of zero and one in which one indicates a collusive regime. Taking logarithm from both sides of Equation (1.10) we can derive the supply relationship:

$$\text{Log } p_t = \beta_0 + \beta_1 \text{ Log } Q_t + \beta_2 S_t + \beta_3 I_t + U_{2t} \qquad \text{Supply function (1.11)}$$

[13] For a detailed discussion of dynamics of scarcity rent see Farzin (1992)

[14] For example as a result of anticipating a recession, price of oil in future may be expected to fall so the scarcity rent would decrease. After this concern regarding recession is removed, the scarcity rent would increase again so the scarcity rent is almost as volatile as oil price itself.

where S_t are shocks to supply in the oil market and U_{2t} are assumed to be iid normal across periods. Furthermore,

$$\beta_0 = \log D$$

$$\beta_1 = \delta - 1$$

$$\beta_3 = -\log\left(1 + \frac{\theta_t}{\alpha_1} - k_t\right) \qquad (1.12)$$

Given these parameter values, we can calculate the value of θ_t as follows:

$$\theta = \alpha_1(\exp(-\beta_3) - 1 + k_t)$$

Depending on values of θ we can classify the conduct of market. If $\theta = 1$, OPEC members are following an optimal cartel behavior and market has a competitive fringe,[15] if θ=0, The market is in perfect competition and if $\theta = \sum s_{it}^2$=0.08 the market conduct is closer to a Cournot behavior with a competitive fringe. However, it is important to notice that in equilibrium $\theta = 1$ might not be supported by the set of trigger strategies and punishments. In fact, at $\theta = 1$ agents could earn maximum profit but on the other hand they have more strong incentive to deviate from optimal cartel behavior because the gain from deviation would be higher in case all other members of cartel are following the optimal cartel behavior. As a result, we would not expect to see $\theta = 1$ case in equilibrium of this repeated game but a $\theta \in (0,1)$ which as θ gets closer to 1 the regime is more collusive and as it goes to zero, it will be more competitive.

Similarly, when the scarcity rent is present in a market, in case of perfect competition the price is higher than marginal cost so the difference between the payoff

[15] For a detailed discussion of a dominant firm with a competitive fringe see Church and Ware (1999).

from colluding or deviating to a non-cooperative case is less than a market in which scarcity rent effect is not present. As a result, we would expect that in a market with a high scarcity rent collusion is more sustainable, frequency of punishment periods is low and their duration is also short.

If the collusive and non-collusive periods were known, the estimation of parameters of above model would be straightforward using a two step least squared method but unfortunately this is not the case. However, using simultaneous switching regressions approach proposed by Kiefer (1980) we can use maximum likelihood estimation approach to estimate both parameters of the model and also identify the collusive and non-collusive periods.[16]

1.3. DATA

In this section I will discuss about data sources and summary statistics. To estimate scarcity rent, I obtained the marginal extraction cost of oil wells from EIA (2003) and EIA (2007) which have annual extraction cost data from 1986-2006. The above mentioned reports have detailed cost data for different categories of oil wells. Data for each category is generated by taking average of costs for 10 typical oil wells of the category. I picked the highest cost wells which were most costly oil wells in USA due to their characteristics (8000ft depth) and also costly extraction technology (water injection) used in extracting oil. I also use price of the corresponding oil type (West Texas Intermediate) for estimation of scarcity rent.

[16] For a detailed discussion of the estimation process refer to Porter(1983)

Variable	2006 value	Mean	Min	Max	Standard deviation	Measurement unit
World oil consumption	85138	72441	61163	85138	15949.5	Thousand barrels/day
West Texas Intermediate oil price	65.14	45.795	26.45	90.10	27.38	2006 $/barrel
World real GDP growth	3.8	3.6	3.4	3.8	0.29	% growth
Marginal extraction costs	36.56	23.9	11.23	36.56	17.91	2006 $/barrel

Table 1.1: Summary statistics for the variables used in estimations

Since scarcity rent estimated is central to the estimation procedure and it could vary according to major regime changes in other periods of time, and also because I did not have cost data from years before 1986, I preferred to limit the dataset time span to cost data time span. To maintain consistency and validity of my estimations, I use the same time span for my estimations although I use quarterly data[17] to be able to obtain better estimations. Hence, I will use quarterly data on oil production and real prices

[17] Although the data are quarterly, because the demand for oil at every period is worldwide which has all different kind of weather I have not included seasonal dummies. Besides that, since the supply chain of oil is in most cases vertically integrated, it takes several weeks from the start of extraction until the retailers deliver the product to consumers and hence the effect of seasonal changes is not so significant.

(2006 Dollars) from 1986 quarter 1 to 2006 quarter 4.[18] This data were obtained from Energy Information Administration website. To construct supply and demand shocks I used information on EIA annual chronology of the oil market to find major supply and demand increase or decreases. The data on real GDP growth was obtained from the World Bank development indicators. The data is summarized in Table 1.1.

1.4. Estimation Results

In this section, I will discuss about estimation procedure and estimated results.

1.4.1. Scarcity Rent

Figure 1.1 shows marginal extraction cost (black) and crude oil price (grey) for 10 oil wells in west Texas during 1986 and 2006. According to EIA (2007), these oil wells were most costly oil wells in USA due to their characteristics (8000ft depth) and also costly extraction technology (water injection) used in extracting oil. The data for this estimation was obtained from EIA (2003) and EIA (2007) reports. These reports include operating cost information in several types of oil wells across USA. I used data operating cost of different types of oil wells with different extraction technologies and calculated per unit extraction costs and selected the most costly wells which are deepest oil wells (8000 ft) with the water injection extraction technology which results in the highest marginal extraction cost.

[18] In comparison, Almoguera and Herrera (2007) use a similar data in frequency but their data span is from 1974 to 2004 but the rest of common data are similar. I use cost data that they don't use.

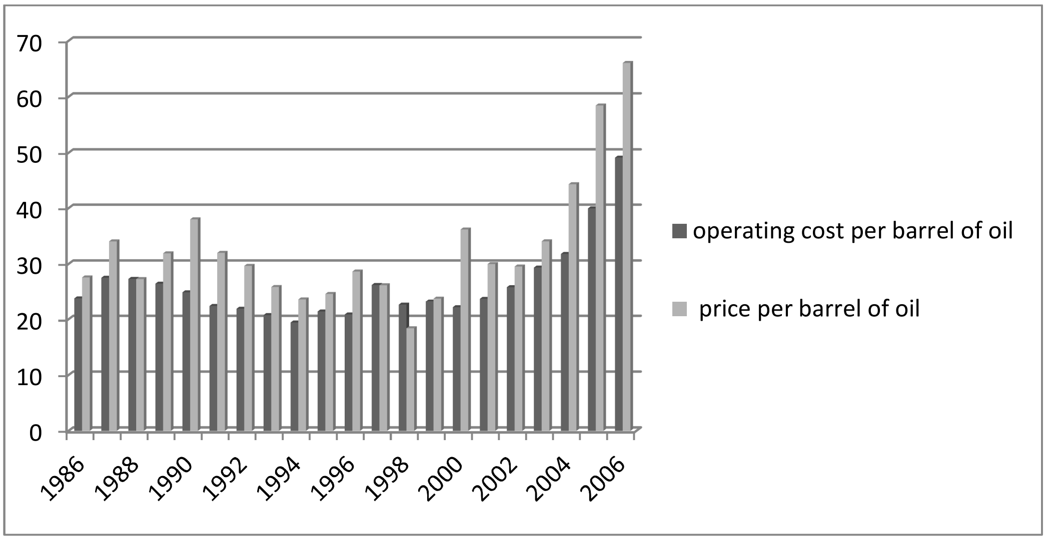

Figure 1.1: Oil price and operating costs for most costly wells in West Texas. (2006 dollars) Source: EIA (2003) and EIA (2007)

I run a regression to test for a relationship between price-cost margin and price at any given point in time. The estimated coefficients are reported in Table 1.2.

Price-cost margin (scarcity rent)	Coefficient	Standard error	95% confidence interval
Price	0.238	0.0229	[0.1901, 0.2853]
			R-squared= 0.8437

Table 1.2: Estimation of scarcity rent from most costly producing wells, derived from the following regression: $SR_t = kP_t + \epsilon_t$

1.4.2. Supply Function Estimation

Although there is not a consensus about estimation of oil supply function but literature on oil demand estimation is well established and agreed upon. I will employ estimation of demand function parameters, specifically a modified version of Gately and Huntington (2002) and insert these estimates[19] into my likelihood function and try to estimate supply function parameters and market conduct.[20] I will use quarterly data on oil production and prices obtained from Energy Information Administration webpage. To construct supply and demand shocks I used information on EIA annual chronology of the oil market to find major supply and demand increase or decreases. The data on GDP growth was obtained from World Bank development indicators.

I developed Matlab[21] programs for estimating Maximum likelihood estimators.[22] The supply estimates are displayed in Table 1.3. The standard errors are calculated using the Berndt, Hall, Hall and Hausman (BHHH) method. Unfortunately they are higher than expected and the estimation results are relatively poor. They can probably be improved by choosing better instruments for my estimation. Standard errors are reported in parenthesis.

Variable	Estimated Supply function coefficients
β_0	-3.23 (1.31)

[19] The estimates of Gately and Huntington is modified to match the data structure I have here and the parameter values are $\alpha_0 = 1.27,\ \alpha_1 = -0.05,\ \alpha_2 = -0.02\ and\ \alpha_3 = 0.91$

[20] I have also tried to jointly estimate both supply and demand functions but parameter estimates in that case where poor and my attempt was unsuccessful. However in next stages of this research I will try to find better instruments for supply and demand and try to jointly estimate supply and demand parameters.

[21] Matlab files are available upon request.

[22] For detailed discussion of this approach refer to Porter(1983)

β_1	3.08 (1.96)
β_2	0.21 (0.14)
β_3	-30.21 (12.73)

Table 1.3: Supply function estimated coefficients, used to back up production function parameters (Standard error in parenthesis)

From above estimates we can derive:

$$\beta_1 = 3.08 \Rightarrow \delta = 4.08 \qquad (1.13)$$

$$\beta_3 = -30.21 \Rightarrow \theta = 0.038 \qquad (1.13')$$

It is worth noticing that $\delta = 4.08$ represents a relatively inelastic supply function, which is a reasonable result. Also resulted estimate for $\theta = 0.038$ is almost consistent with Cournot behavior rather than collusion.

The estimated sequence of I_t converged to zero for all periods of sample which indicates that according to my estimates in fact OPEC failed to effectively cooperate on increasing prices in this sample period. This can be justified by high incentives to deviate from optimal collusive behavior among OPEC members because most OPEC countries governments are heavily dependent on oil revenue. This estimate for I_t is in fact consistent with Lin (2007) result which does not find evidence on collusion during 1989-2004 period. My result is to some extent consistent with Almoguera and Herrera

(2007) which identify rare collusion periods during same period of time. However, Almoguera and Herrera (2007) demand function specification is different from mine because in contrast with the literature on demand estimation for oil, they do not include lagged consumption in their demand function so their price elasticity is relatively high which may result in some bias in estimating collusive periods. However, if I impose SR=0, my estimate of θ would become 0.0521. They have derived this number to be 0.1161 which should be the effect of difference in demand specification we have rather than scarcity rent.

It might seem unreasonable that I_t is zero in all periods in my estimation. In fact it would be better if our estimates showed that for some periods this sequence is nonzero. However, this will not result in a problem with identification of β_3 or θ . This is because in fact the sequence would not converge to 0 itself but it is derived from regime classification probabilities when the stopping criterion is reached. Similar to Porter (1983), in my estimation, I calculate the regime classification sequence $\{w_1, \ldots, w_T\}$. As Lee and Porter (1984) show, the total probability of misclassification would be minimized if classification series $\hat{I}_t$ is generated according to the rule that

$$\hat{I}_t = \begin{cases} 1 \; iff \;\; \widehat{w}_t > 0.5 \\ 0 \quad otherwise \end{cases} \qquad (1.14)$$

So as it is clear from discussion above, even if $\hat{I}_t$ is equal to zero for all periods, it does not mean that the probability of being 1 is zero but it means that this probability is less than half.

It is important to notice that, if we assume that oil is not exhaustible, the estimation that we derive for θ is higher than when we consider exhaustibility. This shows that some of market power estimated for OPEC in the literature might in fact be exhaustibility effect rather than pure market power. To summarize, including Scarcity rent would decrease our estimate for OPEC market power so at least a fraction of markups observed in the market can be attributed to exhaustibility.

1.5. CONCLUSION

In this paper I tried to test whether OPEC exercises market power in the oil market or exhaustibility causes a positive price-cost margin. I considered the exhaustibility of oil and formulated an infinite horizon optimization problem that producers face. I imposed some functional form assumptions. To get a equation form that can be estimated I estimated scarcity rent empirically. Using this estimation I derived a loglinear supply function. I estimated supply function parameters and also identified collusive and noncollusive periods using Porter (1983) approach. The estimation showed that there is not much evidence on collusion during this period of time and including scarcity rent would even decrease the level of market power estimated by model. Supply function parameters estimates are also reasonable.

Next step for this research would be trying to estimate both supply and demand functions jointly. In order to do so I will need to find some supply and demand shocks to be able to estimate the simultaneous supply and demand equations. I have made strong functional form assumptions that should be relaxed in next versions of this paper. My operating cost data was limited to 1986-2006 which resulted in a limitation of time period investigated. A future step, which is beyond the scope of this dissertation, is to find other proxies for scarcity rent that could serve for a longer period of time so that I can expand the time scope of this estimation to include more variation in prices which will increase the probability of including collusive periods in my sample.

Chapter 2: Empirical Evaluation of Oil and Gas Companies' Investment Decisions: A Real Options Approach

2.1. Introduction

Lack of flexibility to adjust production rates among oil and gas producers contribute to an inelastic supply in global energy markets where slight perturbations in demand translate into significant fluctuations in prices. Creating extra production capacity requires exploration and development activities, which involves drilling wells into the earth to reach deep layers of hydrocarbon rich rocks. Thus, drilling is the central activity to extract oil and gas from untapped underground reservoirs. This explains why oil and gas companies spend billions of dollars on drilling each year therefore drilling activities' costs constitute the majority of their capital expenditure in exploration and development of new production capacity.

Drilling equipment, often referred to as "drilling rigs", are mobile equipment that are transferred to the drilling location, perform the assigned task which usually takes a few months and then transferred to the next drilling location. The long-term production requires installation of a production platform. Specialized service companies own the drilling equipment and rent them out to petroleum companies. According to oil industry experts, the rental cost of this equipment can be so large that in the case of offshore drilling it can reach up to 70% of cost of new well development.[23] Hence, these rental rates can affect the decision of oil and gas companies either to undertake an investment opportunity or to wait for better market conditions.

[23] The author has obtained these information through verbal communication with the industry experts.

We have obtained a unique dataset on the rental market for offshore drilling rigs. Since drilling rigs are in fixed supply in the short-run, one can infer the value of the option to wait by examining the rental rates of drilling rigs. For instance, if firms decide to wait and postpone their investments, demand for drilling rigs drops so the rental rates will decline, which in turn increases the incentive to drill. This balancing force adjusts the rental rates in the drilling rigs market so that in equilibrium the marginal firms become indifferent between investing today or waiting for one period. We exploit this equilibrium dynamic in our theoretical simple real options model.

Unique characteristics of exhaustible natural resources require distinct approaches in evaluating related investment projects. On the one hand, unlike many other investments, the capital expenditure for developing an offshore oil field is almost entirely irreversible as the scrap value of the projects is close to zero. On the other hand, the developer of an unexploited oil field often has some discretion over the timing of exploiting this one time opportunity to invest. The irreversibility and discretion over timing of the investments make these types of investment opportunities comparable to financial call options.[24]

A call option gives its holder the right, but not the obligation, to pay a certain price and receive the underlying asset. The interested party should pay a fee (premium) in advance for this right. A "lease" for an oil or gas field, for instance in the Gulf of Mexico, has properties parallel to a call option. To own the right to develop a certain

[24] Considering the possibility of exercising these options at any time, these investment opportunities are similar to American-style call options.

block in the Gulf of Mexico, petroleum companies participate in an auction. The winner of the lease pays a fee and obtains the right to start drilling for a certain period of time, typically 5-8 years. If the lease owner does not start drilling in the predetermined time window, they will lose their right to drill at the expiration date of the lease. However, if they start drilling, they will maintain their right for as long as they operate on that block. Once the drilling begins, the owner of the lease has exercised her option; she no longer has the discretion to wait for further information to arrive in future.

One major deviation of an offshore investment opportunity from a financial call option is in its "exercise price". The owner of a call option knows in advance the exact price he has to pay to exercise his right whereas a lease owner in an offshore oil field will learn about exact costs of development after it obtained the lease. We allow the strike price to vary in our model. Factors that affect the value of this "option" will not be incorporated in the option value itself (lease bid) but in the exercise price (cost of development)

Offshore oil and gas investments are best analyzed using real options approach. We develop a simple real options model in which the prices for capital goods are determined in equilibrium. This simple yet powerful model provides intuitive insights into the market for investment equipment in the oil and gas industry. According to the model, companies facing investment opportunities can decide to invest now or postpone their investment decisions. Their decisions are based on current and past market conditions as well as their expectations about future variables given all available information at each point of time. If they decide not to exercise their "option" and stay away from investing, the market for relevant capital goods will be affected as demand for these goods declines. In a relatively competitive market for capital goods, a drop in demand for this equipment will drive prices of capital goods down. Hence, today's investment costs will adjust so that energy companies' propensity to invest equates across different time periods and the option value of waiting goes away. We exploit this prediction of the model to form our hypotheses and derive our empirical strategy. We propose a novel way to empirically measure the demand for investment goods and control for different contributing factors in order to test our hypothesized predictions.

Our real options model enables us to derive testable predictions. The uncertainty about the future increases the value of the option to wait hence it will discourage investments in the present. Additionally, the more firms discount future cash flows, the lower the opportunity cost of waiting. The arrival of new information also plays a crucial role. If an investor receives an information signal that is indicative of higher prices in the future, the expected opportunity costs of waiting will increase. The firm will lose out if it has not built the required production capacity to produce when prices increase. Hence, any information regarding market anticipation of prices in the next periods, affects the value of the investment opportunity.

Futures contracts incorporate information signals about future prices. These contracts have been widely traded on exchanges during the past few decades. As the trading volume grows over time, these contracts become liquid and can serve as a frictionless reflector of the market's expectation of actual prices in the future. If we assume that futures contracts are efficient aggregators of market players' perceptions about the evolution of prices in the future, higher futures prices will decrease the value of the option to wait.

All arguments so far were based on the assumption that firms can undertake any project they perceive as profitable. This assumption is only true if perfect capital markets exist. In a real world with capital constraints and financial frictions, some firms may consider a project profitable but they may simply not be able to secure the required funds to proceed with the investment. If the firms are heterogeneous in their access to capital, they may behave differently even when facing similar investment opportunities. In other words, firms with low financial constraints will invest more aggressively in response to changes in the real option value while firms with high financial constraint will be less responsive to these changes. Additionally, these financially constrained firms will be heavily dependent on any factor that mitigates their financial constraint, such as their past earnings and looser credit markets. Consequently, financially constrained firms are expected to be more sensitive to past cash flows in their investment decisions, whereas firms with less financial constraints are expected to be more forward-looking. This will form the second building block of our empirical strategy.

Data limitations are the major obstacles in empirically testing the above hypotheses. Ideally, we would prefer to look at the investment activity of all active firms in a specific sector, for instance the oil and gas industry. However, majority of these firms are not publicly listed companies and as a result they are not required to publicly report their balance sheet information and financial statements. Furthermore, limiting ourselves to the smaller universe of publicly listed companies would entail several problems. First, the sample size shrinks significantly, which will leave us with very low power. Second, focusing on publicly listed companies will pose selection bias. Third, the frequency that the publicly listed companies report their investment activities is at best quarterly which will further reduce our tests' power whereas other market variables are easily available in monthly frequency. Last but not the least, a significant number of major oil producers are NOCs (National Oil Companies). NOCs are large players in the global energy markets, but they often do not make their financial statements available to public especially in the developing world countries. These facts increasingly motivate us to seek alternative approaches rather than limiting ourselves to publicly listed companies. We address data limitations by using general proxies for oil companies' demand for investment, past earnings and access to capital markets. These proxies can be used for a vast set of oil companies. This approach enlarges the set of companies in our dataset and makes it almost 10 times larger than the set of publicly listed companies.

To find an appropriate proxy to measure the oil companies' demand for investment, we restrict our attention to offshore projects. We use data on costs of developing offshore oil and gas projects to derive a proxy for propensity to invest. Developing an offshore field requires drilling thousands of feet below the seabed using floating drilling rigs. The oil and gas companies do not usually own these drilling rigs, due to high opportunity cost of idle equipment. The daily rental rates for offshore drilling rigs are colossal and can reach hundreds of thousands of dollars. According to oil industry experts who have been interviewed by the author, the mere rental costs of the drilling rigs can reach 70% of the development cost of oil fields in offshore projects. As a result, rental rates of drilling rigs can serve as a proxy for oil and gas companies' capital expenditure.

We have acquired a novel dataset that contains 15000 detailed rental contracts for drilling equipment, which virtually covers all offshore drilling projects during 1999 to 2010. Specialized service companies own these drilling equipment and rent them out to oil and gas companies. Our dataset contains all rental contracts of the offshore drilling rigs from 1999 to 2010 with exact contract fixture date, contract start and end dates along with equipment technical details, drilling location, operating company, type of contract, etc.

Since the rental cost of this heavy equipment covers the major cost of developing an offshore oil field, it is an appropriate proxy for investment costs. Construction of these drilling rigs is very time-consuming and can take several years to complete. Thus, the supply of this equipment is fixed in the short run. As a result, any short run shift in the demand for these rigs will be directly reflected in their rental rate (price). Thus, using these rental rates, we can construct a measure of demand for investment by oil companies.

Finding a measure for past earnings proved to be nontrivial as 90% of companies in our sample universe are not publicly listed and those which are public companies, do not report their earnings on a monthly basis. To obtain a better measure for this variable we assume that past earnings of oil companies are highly correlated with the corresponding oil prices in the same period. This assumption can be justified if oil companies investing in a new project have a portfolio of relatively similar oil wells. Considering the quite advanced technology requirements of offshore drilling and essential expertise for entrants to this segment of the market, we believe that this assumption is plausible.

There are more than 500 oil companies in our database; among these, almost 450 are not publicly listed. We observe that the concentration of publicly listed firms is higher in higher water depth and it almost uniformly increases as the water depth increases. The higher water depth also corresponds to more costly rental rates simply because more advanced technology is required in deeper water. We assume that the publicly listed firms have easier access to financial markets because they can issue bonds and are well known (Thus they can secure commercial loans more easily). As a result, operating in deeper water is partially correlated with lower capital constraints.

Our results show that as the water depth increases the forward looking effect, reflected in the response to futures markets, becomes dominant while the effect of financial constraints, measured by dependence on past earnings, decreases. We control for a variety of market variables as well as technical and geographical features in our econometric model. We try different econometric specifications to test our hypothesis, most importantly Fixed Effects Panel data models. We run our analysis for different regions of the world, where data is not too limiting, and the results are almost uniformly consistent across different regions and specifications.

Section 2 is dedicated to motivation and the literature review. Section 3 provides a simple real options model to provide a theoretical framework for our analysis. Section

4 discusses the institutional setting in oil and gas investments and the industry background. Section 5 describes the methodology and the data we use. Results are discussed in section 6. The paper conclusion is presented in section 7.

2.2. MOTIVATION AND BACKGROUND

Hydrocarbons (crude oil, natural gas, etc) have been the main source of energy in daily life during past century and they continue to play a crucial role in the world economy. One important feature of oil prices is their high volatility. This is partly because of very tight supply and inelastic demand, which help slight interruptions in supply or changes in demand create significant fluctuation in oil prices. On the other hand, concentration of the majority of petroleum reserves in relatively limited locations, specifically OPEC countries, makes energy independence a priority for developed countries. There are debates about whether OPEC can effectively exert any market power,[25] nonetheless developing new energy sources makes the world economy less susceptible to supply interruptions such as the ones in Libyan unrest in 2011, the first Gulf war in 1991, and the Arab Embargo in 1970s.

Developing better tools to explain capacity dynamics is inevitable for understanding the supply dynamics, which in turn affects prices and volatilities. Numerous methods, including Net Present Value (NPV) analysis, have been developed to analyze investments. However, unique features of natural resources call for special treatment. The exhaustibility of some natural resources like crude oil brings the

[25] Morovati (2010) discusses the OPEC market power and its role and empirically shows that OPEC has in fact failed to exert effective collusion in the global crude oil market.

intertemporal decision to extract the resource to the core of the investment decision. McDonald and Siegel (1986) have shown how the waiting option creates some value that should be considered in the cost benefit analysis of the firm. Real options approach has been widely employed to evaluate oil and gas projects as demonstrated in the seminal work of Brennan and Shwartz (1985). Dixit and Pindyck (1994) provide an excellent introduction to the topic in overwhelming details which applies to the general issue of investment under uncertainty in different setups. This includes investment on capacity building for the extraction of natural resources, which involve several uncertainties; from uncertainty about future prices to technological complexities and probability of substitute discoveries. In a more recent study, Ronn (2004) identifies the critical determinants affecting the timing of oil extraction from an oil field in a real options framework as comprising the level of crude-oil forward prices, the slope of the forward curve, the volatility of crude-oil prices, and the costs of extracting oil from the field in question.

The majority of the literature, up until recently, lacks sufficient data to empirically analyze wide range of natural resource investments. Empirically evaluating investments in natural resources requires relatively granular capital expenditure data. One of the early examples is Paddock et al. (1988), which exploits data on one of the offshore lease auctions in the Gulf of Mexico along with cost estimates from federal agencies to apply option valuation on natural resource projects. More recent examples, which are the closest to our empirical strategy, are Kellogg (2010) and Gilje and Taillard (2012). Both of the above mentioned use data on onshore drilling activity to approach investment analysis. Kellogg (2012) uses a real options model to evaluate Texas onshore oil fields and tries to isolate specific types of investments to capture the optionality value. Their datasets lacks the price data so the mere “intensity of drilling” measured by the number of active firms serves as the proxy for investment. Our dataset in contrast gives us the flexibility to evaluate virtually all offshore projects. On the other hand, the rental rate data gives us much more precise estimate of investment activity. Gilje and Taillard, though closely related, are comparing investment activities of different types of firms using drilling activity for natural gas. Their analysis does not focus on the drivers of the investments per se but on the differences across two different groups of firms.

Our dataset is obtained from RigLogix , an energy industry data vendor. This unique dataset gives us precise estimates of investment costs in offshore drilling market. We employ a theoretical framework, which is an extension of Dixit and Pindyck (1994) giving us strong testable hypotheses. We then test our model using the investment data from petroleum industry, coupled with standard financial and macroeconomic data to evaluate the main drivers behind the investment decisions of oil and gas companies.

It is important to notice that we are mainly focusing at the petroleum investments by private sector (not the governments). All the investments considered in this paper in effect contribute to the capacity building within a competitive fringe, which is price taker in crude oil market. The majority of world supply of petroleum is produced in Middle East and Russia with extremely low marginal extractions costs. In this research we abstract away from price effects of the investments by firms in our database, as their size is negligible compared to the dominant players of the market.

2.3. Real Options Model for Rental Rates

In this section, we develop a simple real options model to analyze the investments in oil and gas capacity building, especially in offshore projects. The required large upfront costs and relatively low operating cost makes offshore oil projects especially interesting. The model has some simplifying assumptions that depart from reality but it provides intuition into the problem and serves as a primer to the unfamiliar reader. The more sophisticated model in continuous time using Geometric Brownian Motion also yields similar predictions. Since we are not particularly interested in estimating a specific model parameterization, we simply rely on this discrete time model for comparative statics that will help us construct hypotheses for our empirical tests.

2.3.1. Model Setup

Consider a risk-neutral price process for a commodity, such as oil, in which the uncertainty regarding future prices is resolved after one period and the price remains constant afterwards.[26] There are two possible future states in the economy: high and low: $s \in \{H, L\}$. The commodity price at time zero is p and can increase to $p_t = p + \mu + \alpha \ \forall t > 0$ if the high state of the economy realizes. The price decreases to $p_t = p + \mu - \alpha \ \forall t > 0$ if the low state realizes. For the sake of simplicity, assume that these two states occur with the same probability so $E(p) = p + \mu$ or equivalently, the futures contract price for these commodity will be $p + \mu$. Note that μ is similar to the level of a

[26] It is important to notice that by making these assumptions we are departing from the traditional geometric Brownian motion often assumed for oil prices.

drift in a random walk process and α is positively correlated with the variance of the expected price. Figure 2.1 provides a graphic representation of the model.

The potential investor has the option to invest now or wait and invest later. The investment is irreversible. Since the uncertainty is resolved at time t=1, it follows that if the investor does not find it optimal to invest in period one, it will not be optimal to invest in any subsequent period. Hence, without loss of generality, we can assume that the investment decision can take place either in period zero or period one.

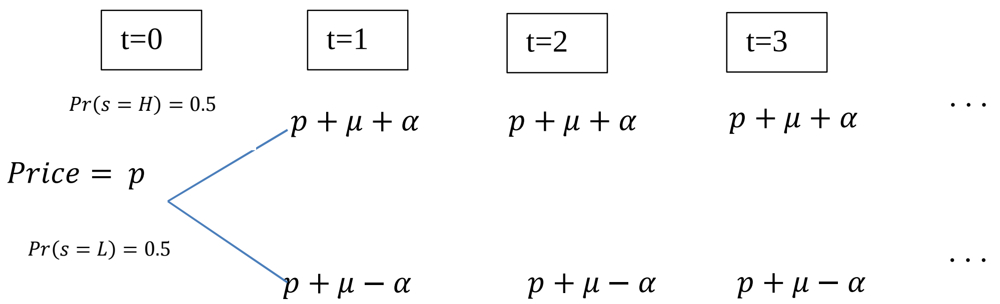

Figure 2.1: Timeline of the real options model

Further, assume that undertaking the investment creates capacity that will come online next period. In deciding whether to invest or not and when to invest, the investor considers the NPV of expected cash flows from different scenarios. Waiting one period resolves the uncertainty but the investor will incur the opportunity cost of foregone cash flows from period one. On the other hand, investing in period zero may yield positive

NPV in expectation but ending up in the low state of the world will impose a loss on the firm so it creates a conflicting incentive to delay investments.

Suppose I_t denotes the investment costs in period t and that the investors can finance their investment costs from capital markets with a loan that incurs per period interest rate r. We calculate the NPVs for each of the possible scenarios to find the optimal decision to invest or delay investment. NPV_0 denotes the net present value of the project if the investment takes place at period zero.

$$NPV_0 = -I_0 + \frac{1}{2}\sum_{t=1}^{\infty}\frac{p+\mu+\alpha}{(1+r)^t} + \frac{1}{2}\sum_{t=1}^{\infty}\frac{p+\mu-\alpha}{(1+r)^t}$$

$$= -\mathrm{I}_0 + \frac{(p+\mu)(1+r)}{r} \qquad (2.1)$$

Note that the expected NPV is calculated by incurring the investment cost at time 0 and collecting the expected stream of cash flows resulting from the capacity created in all subsequent periods. Similarly, NPV_1^s denotes the net present value of the project, calculated at t=0, if the investment takes place in period one when the state of the economy is $s \in \{H, L\}$. Further assume that if low sate of the economy occurs, the value of parameters is such that $NPV_1^L < 0$ hence investment is not optimal in bad states.

$$NPV_1 = \frac{1}{1+r}.\frac{1}{2}\left(-\widetilde{I_1} + \frac{(p+\mu+\alpha)(1+r)}{r}\right) \qquad (2.2)$$

Note that the investment costs in next period is a random variable that can change, hence $\widetilde{I_1} = E_0(I_1)$ is used which denotes the expectation formed about future investment costs given the information available at time 0. [27]

I_t in offshore drilling industry mainly consists of the rental rate for drilling rigs. These rental rates are determined in a competitive market. They should adjust so that given all the information available at each point of time, the investors are indifferent between investing now or postpone the investment for one period (If this is not the case, for example if the investors strictly prefer to postpone their investments, demand for drilling rigs decreases, so their demand curve shifts left, their rental rates declines until the investors become indifferent.)

Hence we reach an equilibrium condition in which I_0 adjusts such that $NPV_0 = NPV_1$

$$NPV_0 = NPV_1 \qquad (2.3)$$

This equilibrium condition helps us solve for I_0 in equilibrium

$$\Rightarrow \ -I_0 + \frac{(p+\mu)(1+r)}{r} = \frac{1}{1+r} . \frac{1}{2}\left(-\widetilde{I_1} + \frac{(p+\mu+\alpha)(1+r)}{r}\right)$$

$$\Rightarrow I_0 = \frac{(p+\mu)(1+r)}{r} - \frac{1}{1+r} . \frac{1}{2}\left(-\widetilde{I_1} + \frac{(p+\mu+\alpha)(1+r)}{r}\right)$$

$$\Rightarrow I_0 = \frac{(p+\mu)(1+r)}{r} + \frac{\widetilde{I_1}}{2(1+r)} - \frac{(p+\mu+\alpha)}{2r} \qquad (2.4)$$

[27] In fact, we are allowing for a second source of uncertainty in our model which the risk premium associated with it is zero.

This equilibrium pricing of drilling rig rates, to the best of our knowledge, has been new in the literature and can be extended, given data availability.

We can do some comparative statics to see how changing different parameters of the model affect the rental rates today (which are proxies for Investment costs)

$$\frac{\partial I_0}{\partial \alpha} = -\frac{1}{2r} < 0 \qquad (2.5)$$

$$\frac{\partial I_0}{\partial \mu} = \frac{1+r}{r} - \frac{1}{2r} = \frac{1+2r}{2r} > 0 \qquad (2.6)$$

$$\frac{\partial I_0}{\partial r} = -\frac{p+\mu}{r^2} - \frac{\widetilde{I_1}}{2(1+r)^2} + \frac{(p+\mu+\alpha)}{2r^2}$$

$$= \frac{\alpha - p - \mu}{2r^2} - \frac{\widetilde{I_1}}{2(1+r)^2} < 0 \qquad (2.7)$$

2.4. INSTITUTIONAL SETTING

2.4.1. Drilling Industry

Large deposits of hydrocarbons may be available deep under the surface of the earth in different forms such as crude oil, natural gas, etc. These stocks are often underground deposits of hydrocarbons trapped within porous rocks under immense pressure. A majority of conventional oil and gas production projects involve drilling an oil well into this high-pressure reservoir and the resource simply starts flowing, at least during the early stages of production, due to its high pressure. A tract of land or sea that contains oil reservoirs is referred to as oil field,[28] usually extending several miles across.

[28] Most of the hydrocarbon reservoirs contain both oil and gas. If the hydrocarbon reservoir mainly contains natural gas, the field is called gas field. In the rest of this paper, we will simply refer to crude oil for much of our study but our results are easily extended to natural gas as well. In fact, in most of the conventional hydrocarbon reservoirs both oil, gas and sour water are trapped under a dome like hard

Extracting the resources out of the deep reservoirs requires sophisticated techniques depending on several factors including the geology of the oil field and the type of resource. In the conventional form of oil reservoirs, which is still the far dominant source of energy in the world economy, extraction requires drilling one or several wells into the reservoirs, which occasionally lie several thousand feet below the surface of the earth. Once the wells are completed, crude oil usually starts flowing out. Because of this outflow, the pressure within the reservoir starts to fall, which may necessitate artificial lifting techniques for further production, often referred to as Enhanced Oil Recovery (EOR). At current available technologies, a fraction of existing oil and gas is recoverable even with most advanced EOR methods and the majority of the reserve will remain under the ground.

The crucial step in bringing a hydrocarbon field into production, or so called "development" of a hydrocarbon field, is the advanced techniques of drilling appropriate wells. The wells, occasionally less than a foot in diameter, often pass through several thousand feet of rocks to reach the reservoir.[29]

rock surface, deep under the ground. Although the oil production form unconventional reservoirs like tar sands or shale oil has recently been on the rise, nonetheless more than 95% of current oil production of the world remains from conventional resources. Natural gas is entirely different mostly because prohibitively large transportation costs prevent it to be transferred easily across different regions of the world. As a result, there is no unified market for natural gas and it is traded regionally. Interestingly, shale gas revolution in USA, which employs a technological breakthrough to free up large deposits of unconventional natural gas reservoirs, has transformed the natural gas industry in North America (See Martin et al., 2012 for more details about Shale Gas Revolution and its economic consequences and Morovati (2013) for an empirical evaluation of shale gas revolution on US manufacturing). This increase in supply has caused a severe drop in the price of natural gas in the US market, which in turn has deep consequences on energy markets as a whole. However, much of our discussions remain valid specifically about crude oil. We will consider the shale gas revolution as an exogenous shock to the market and briefly discuss how we can observe its consequences in our empirical results.

29 Recent advances in drilling techniques has been a major enabling component of shale gas revolution. Horizontal drilling, once beyond imagination, requires directing the drilling bit, thousands of feet under

2.4.2. Offshore production

Although there are large oil fields both onshore and offshore, the upfront costs for developing offshore oil production facilities are often larger. Drilling in offshore environments takes place to tap into the hydrocarbon resources captured under the seabed. Offshore drilling often requires technologies that are more sophisticated. It also requires additional protective measures to mitigate the risks involved such as environmental risks, severe weather risks and potential petroleum leaks. The remote locations and harsher environment create challenges and much of the costs associated with developing offshore oil fields are due to overcoming these challenges. The DeepWater Horizon disaster in April 2010 provides an example of the immense potential risks involved. This drilling rig exploded leading to leakage of several thousand barrels of oil into the Gulf of Mexico totaling at about 5 million barrels of oil. The explosion of the drilling rig is estimated to cost BP, which was the operator of the rig at the time, more than $40 billion in cleanup costs and lawsuits. The costs are still rising.[30]

2.4.2.1. Acquiring the Drilling Right

In much of the developing countries the drilling right falls within the hands of the state. The National Oil Companies undertake large investments and no other entity can obtain the right to development. Major examples include the Persian Gulf petroleum states. In contrast to the developing world, the rich countries' governments do not

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the surface, to make a vertical turn and penetrate the hydrocarbon layers, often parallel to the earth surface.

30 http://www.guardian.co.uk/business/2012/nov/15/bp-fine-draw-line-deepwater

directly get involved in producing crude oil and natural gas. The right to development of an oil field either is inherently for the owner of the land or is offered to private companies through a competitive bidding process. The entity with the right to development may develop the field and earn cash flows from selling the resource if the investment is successful. The government earns taxes and royalties from natural resources.

For an specific example we turn our attention to the details of the bidding procedures in the Gulf of Mexico. The Bureau of Ocean Energy Management[31] (BOEM) is responsible for managing and administering the petroleum production in the federal regions of the Gulf of Mexico. BOEM has divided the Gulf of Mexico into a blocks grid, each containing several square miles, usually in the form of rectangular tract.[32] Energy companies can perform seismic analysis in advance to evaluate the potential chance of hydrocarbon discovery in each tract. BOEM offers a set of tracts for sale and energy companies can compete in the bidding process to win the lease. The winning bid pays the sale price and obtains the right but not the obligation to start developing the petroleum field for certain period of time, usually 5 or 8 years. If a company starts developing a field, it keeps the right to production from that field for as long as it wishes to pay the associated fees and royalties. If a lease owner decides to abandon a tract and not to develop it after the expiration of the lease, the tract will return to the stock of BOEM tracts and becomes available for potential future auctions.

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[31] BOEM.gov

[32] For a precise map of the grid blocks please download the following pdf file http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Mapping_and_Data/visual1.pdf

The tract lease is analogous to a call option. To own the lease the winning bid has to pay certain fees, similar to the price of a call option. Owning the lease gives the owner the right but not the obligation to start drilling in order to make the lease productive and create future streams of income. The owner will only start developing if she finds the development worthwhile or in other words finds the expected future cash flows more valuable than the development costs. There exists a threshold in the discounted expected value of the future cash flows above which the lease owner pays the drilling costs and develops the field to earn the future cash flows. The development cost is similar to the strike price of a call option and the discounted expected future cash flows is analogous to the value of the underlying asset in a call option.

2.4.2.2. Institutional Settings in Drilling Rig Market

Offshore drilling rigs are huge mobile equipment that are used to drill wells in the seabed to reach the petroleum reservoirs. Figure 2.1 illustrates different types of offshore drilling rigs, employed for different water depths. Figure 2.2 demonstrates a sample drilling rig in operation. This equipment is usually owned by petroleum service companies (e.g. Transocean) and rented out to oil companies (e.g. BP). The daily rental rates are often fixed at the contract fixture date but in some rare cases that the contract duration is several years it is indexed to the rental rates of a similar equipment portfolio. Table 2.1 shows a summary statistics of the rental rates for our database. The daily rental rates can be as high as $700000 which can easily reach $100 million in drilling costs for a drilling job that lasts 4-5 months. Offshore projects require large upfront investments to yield an uncertain production rate in future which can generate cash flows for the investor. The major cost of developing an offshore oil field is the rental cost of drilling rigs which reaches 60-70% of total development cost for ultra deep projects. We use this fact to construct our measure of investment costs in the offshore oil and gas industry.

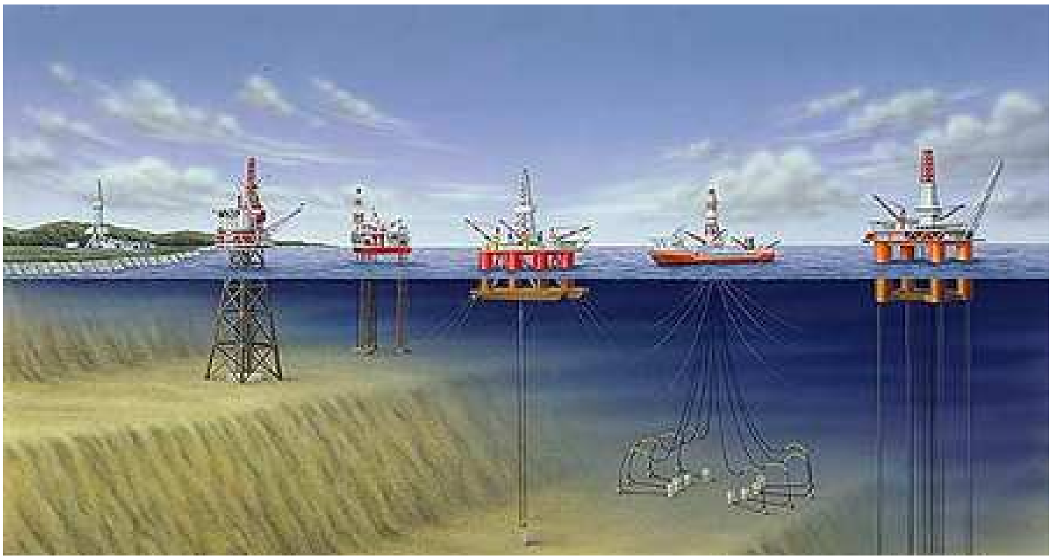

Figure 2.2: An illustration of different types of drilling rigs

Figure 2.3: Semisub Drilling Rig in Operation

Figure 2.4: Semisub Drilling Rig en Route to new location. To better appreciate the size of this drilling rig, note the size of the 6-story building on the deck of the carrier vessel towards the front of the carrier ship.

Offshore drilling rigs are often contracted for short periods of time usually from several weeks to months. They are transferred to the drilling location, perform their drilling task and finally removed from the location and transferred to the location of their next drilling job. Once the drilling equipment is removed from the project location, the production facility is installed which will permanently remain on site.

Mean	101
Median	60
Mode	55
Standard Deviation	107
Maximum	703
99th percentile	510
1st percentile	10

Table 2.1: Summary statistics for drilling rigs costs: Daily Rental Rates ($ Thousand). [33]

A drilling rig in the process of being transferred to a new location has been demonstrated. Although drilling rigs can in theory be transferred to anywhere, the high opportunity costs of the time spent on long routes effectively creates regional markets within which the drilling rigs are employed for offshore projects in a relatively competitive market. The relative isolation of each region is one reason that wide differences in the rental rates of similar drilling rigs may be observed in the short run across different regions of the world. New entry due to construction of the new rigs and movability of rigs across regions will reduce this gap in the long run but it may not be fully eliminated merely because of other factors such as geopolitical and climate differences and market concentration.

[33] Notice that this is an unconditional distribution of the rental rates to give a quick idea about the industry. Clearly the distribution will be much tighter when a drilling decision is to be made as the potential candidate rigs will be in a subset of the distribution.

There are several service companies present in any of major oil and gas producing regions of the world such as Gulf of Mexico, North Sea (between UK and Norway), Persian Gulf, West Africa, etc. The largest drilling companies in the Gulf of Mexico with aggregate market share of about 60% are Transocean, ENSCO, Diamond Offshore, Noble Drilling and Rowan. The largest market share belongs to Transocean with 15% of 5570 contracts. In addition to the above companies, which are the most active firms in the Gulf of Mexico, three other service companies are also among top 8 drilling companies: Parker Drilling, Pride International, GlobalSantaFe. The top eight own 65% of the overall market share. As evident in the market concentrations, though far from perfect competition, the market for drilling equipment is not highly concentrated and prices are not substantially different from overall costs, both explicit and implicit.

The Industry appendix includes more details about the market concentration, the profile of the most active drilling companies, active drilling rigs and different drilling rig types.

2.5. METHODOLOGY AND DATA

Constructing an empirical test of our real options model requires a dataset that contains observations on investment costs, investors' expectations about future prices, measures for tightness of capital markets and the riskiness of the future cash flows. To justify using the real options framework the empirical setup should also fulfill the basic assumptions of irreversibility of the investment and discretion of the investor over the timing of the investment. In this section, these conditions and data features are discussed.

Real options approach is a useful theoretical framework to analyze a wide range of natural resource investments, especially developing an offshore oil and gas field. As described in the industry section, energy companies acquire the right to development of certain block in the sea through a competitive bidding process. They obtain the right but not the obligation to develop the field. After gathering further information through geological tests, they decide whether to go ahead with the investment or postpone it until the right time. If they decide to develop the field, they usually rent a drilling rig from service companies to perform the drilling.

Publicly listed oil and gas companies are required by governmental regulations to make their balance sheets available. Their capital expenditure can be used as a measure of investment costs accrued by these firms. However, using the balance sheet data imposes some serious limitations on our analysis. First, the frequency of publicly available data on capital expenditure is very low (annually for most cases) which given the low number of public E&P firms, enormously decrease the power of our tests. Second, the published data on Capex is on an aggregate level and does not specify each investment opportunity. Investments on a refinery, pipeline, expansion of current production plant or developing a new field are all aggregated together which makes it impossible to identify the determinant factors of developing a new investment opportunity. Third, there are several other smaller private companies that do not publish their balance sheets. Our novel dataset allows us to evaluate investments at the smallest unit of investment in oil industry which is an oil well. The rental cost of drilling equipment construct the majority of the cost of developing an oil field (According to petroleum experts, 60% to 70% of developing an offshore oil field is just the cost of drilling). We exploit this unique dataset of offshore drilling equipment to empirically test our real options model. The dataset contains details of the all offshore drilling contracts between service companies and oil companies during 1999-2010. The contracts include the name of the service company who owned the rig, the name of the oil company that rented the equipment, the contract start and end dates and the rental rates. The dataset also includes the fixture date of each contract, the region and the location of the drilling, and the rated water depth. The technical specifications and rig type allow us to follow each group of the rigs with utmost precision.[34]

The dataset includes almost 15000 contracts for the period 1999-2010. There are 290 oil companies active in our database among which 23 have been identified to be either a publicly listed firm or a subsidiary of a publicly listed one. If we were to restrict our attention to the public companies, we would lose more than 90% of the firms in our sample, though the public subset of the firms in the dataset are more active on average hence resulting in losing much less than 90% of observations.

The drilling data consists of more than 1000 drilling rigs which have repeatedly entered into contracts hence unavailable and become available after the contract was over, hence entering the market again. We abstract away from analyzing the optionality

[34] A detailed description of the data fields present in our data can be found at the data vendor's website: http://www.riglogix.com/RigLogix_Data.aspx

on the supply side of the drilling market for simplicity. Our units of observations are contracts that these drilling rigs frequently engage in so each rig appears several times on our observations.

The concentration of the publicly listed companies is higher in deeper water. This can be mainly attributed to the more technological sophistication and higher required investment costs which is prohibitive to the smaller companies. Large and public firms can access the capital markets more easily and face less financial frictions. To evaluate the effect of financial constraints on the firms in our sample we divide our sample into three different water depths. We run our tests on each bin separately in order to identify the effect of financial frictions.

Drilling rigs are heavy machinery and they are in fixed supply in the short-run. Hence, any changes in the rental rates can be inferred as the change in the value of the option to wait.

As described in the model section, the rental rates will adjust such that in equilibrium firms are indifferent between investing now or postpone their investment. In other words, the value of the option to wait should go to zero. Using this simple intuition, we can use the comparative statics results of our model to construct our hypothesis:

Hypothesis (1): The option value decreases as expected future prices increase, hence the rental rates should increase as the slope of the futures contracts increase.

Hypothesis (2): The option value increase as interest rates increase, hence the rental rates should decrease as the cost of financing the project increases.

Hypothesis (3): The option value increase as uncertainty about future increase, hence the rental rates should decrease as the riskiness of future cash flows increases.

Hypothesis (4): In the absence of perfect capital markets, firms will be more dependent on their past earnings for financing their projects. As a result, firms with higher financial constraint will respond more severely to variations in past earnings. This will in turn lead to more significant change in the rental rates in the corresponding segments of the market.

To test these hypotheses we use a fixed effects panel data model. The advantage of the panel data models is that it allows us to keep track of unobserved characteristics of each rig throughout the analysis. This is particularly of interest because we can't control for all technical details of the drilling rigs. We use the following panel data model specification:

$$I_{it} = \beta X_{it} + \lambda Z_t + d_i c_i + \epsilon_{it} \qquad (2.8)$$

where:

I_{it}: Rental cost of rig i at time t

X_{it}: Contract specific characteristics for rig i at time t

Z_t: Market variables at time t, e.g past earnings, slope of futures curves, etc

c_i: Rig specific unobserved effect

ϵ_{it}: i.i.d. error term

For each observation (contract), we use the contract specific control variables such as the length of the contracts, the contract type (fixed length, fixed work), etc. We also look up the market variables at the time of contract fixture date which are either directly related to our tests or as controls for our regressions.

The slope of the futures contracts with different maturities is our proxy for expected futures prices. If markets are efficient aggregators of available information (efficient market hypothesis), every innovation in supply and demand that can be anticipated will be reflected in futures contracts prices. Hence, futures curves slope serve as our proxy for expected price increase in different time horizons (maturities). It is important to notice that a futures curve in backwardation does not necessarily imply that expected prices are anticipated to decline in future. However, all else equal, a higher futures price implies a higher expected future spot price.

A large number of firms in our sample (more than 90%) are private companies and their balance sheet data is not available. However, given the properties of the industry, we can construct a measure of past earnings. Offshore projects are relatively complicated and prior onshore exploration activity seems to be a necessary step to avoid high failure costs. Entrants to offshore projects are often involved in several other smaller projects elsewhere and own a portfolio of producing oil wells. Hence, we take a moving average of crude oil prices[35] during past six months as a proxy for their past earnings.

Ideally, we would wish to have exact data on borrowing costs of active firms in our sample. Yet since this is not easily available, we revert to aggregate measures for

[35] We use West Texas Intermediate (WTI) throughout this research because of the widespread trading of WTI futures.

overall conditions of capital markets. We use 10-year treasury bill yield as a measure of risk free rate of interest because using short-term treasury bills yields would cause serious endogeneity problems as it is a policy tool that is manipulated by the Federal Reserve. We use the excess yield of 3-month-to-maturity investment grade bonds over treasury bills of the same maturity to capture the excess cost of capital the companies have to incur to access financing.[36]

We obtain the implied volatility of crude oil prices from Bloomberg Terminal. These implied volatilities are derived using a Black-Scholes options valuation model of futures contract of WTI crude oil for delivery in 6 months. We pick 6 month horizon because the longer horizon options are thinly traded so they are less liquid. The options for shorter horizons are usually too noisy as they are closely affected by day to day trading activities.

In addition to implied volatility, we use historical volatility of futures contracts as an alternative measure for volatility. To construct this measure we obtain the standard deviation of futures contract prices for WTI crude oil over a 30-day window. It is important to notice that implied volatility is inherently forward looking. In contrast, the historical volatility is a reflector of past events. However, since historical volatility is readily accessible to more investors and the liquidity concerns involved with thin trading volumes in futures options is absent, we include this alternative measure in our empirical analysis as well.

[36] Note that 90% of firms in our database are not publicly listed companies. However, the spread described above simply captures the tightness of credit markets for a range of companies active in the industry.

2.6. RESULTS

The empirical results are presented in this section. We take natural logarithm of all variables,[37] where feasible, so the results should be interpreted as percentage changes in investment activity as a result of one percentage change in independent variables. We present our estimation results for the whole sample as well as important regions such as Gulf of Mexico and North Sea in Europe. Although the results are slightly different across different regions, they are generally consistent with our four hypotheses.

Table 2.2 presents the estimation results for the Gulf of Mexico region. This region has the most contract details and very few missing values. This can be attributed to overall better quality of data in USA and transparency in procedures and regulations.

Expected futures prices as demonstrated by the slope of futures curve has a positive and significant effect and this effect is almost uniform across different water depth, consistent with hypothesis (1), which states that the option value decreases as expected future prices increase, hence the rental rates should increase as the slope of the futures contracts increase.

Our results do not reject our hypothesis (3) about the effect of implied volatility. Considering our fixed effects panel model, we are in fact lacking enough power neither to reject nor to accept this hypothesis. However, as it is illustrated in Table 4, when we include all observations in the world regression, in some cases the coefficient on implied volatility becomes negative and significant as predicted in Hypothesis (3).

[37] Our dependent variable, rental rate, is a measure of investment costs for developing new oil fields. This variable has a wide range across different rig types and water depth. However, the variation is much smaller within each group of the rig types.

VARIABLES	(1)	(2)	(3)	(4)
Past Earnings	1.323***	1.400***	1.207***	0.962***
	(14.937)	(15.011)	(11.001)	(3.885)
Slope of futures curve	0.460***	0.447***	0.468***	0.435**
	(5.078)	(5.032)	(4.692)	(2.038)
Cost of capital	-0.198***	-0.208***	-0.184***	-0.116
	(-4.099)	(-4.105)	(-3.180)	(-1.195)
Implied volatility	0.005	0.023	-0.109	0.134
	(0.038)	(0.174)	(-0.795)	(0.708)
CONTROLS	Y	Y	Y	Y
FIXED EFFECTS	Y	Y	Y	Y
TIME CLUSTERS	Y	Y	Y	Y
# of Observations	3,354	2,153	869	332
R-squared	0.870	0.851	0.818	0.792

Robust t-statistics in parentheses,
*** p<0.01, ** p<0.05, * p<0.1
Fixed Effects Panel

Table 2.2: Estimation results for the Gulf of Mexico region. Models (1)-(4) correspond to different water depth as follows: (1) All rigs; (2) Shallow water with maximum water depth <350 feet; (3) Medium depth with maximum water depth between 4000 feet and 350 feet; and (4) Deep water with maximum water depth > 4000 feet,

Hypothesis (3) states that the option value increases as interest rates increase, hence the rental rates should decrease as the slope of the cost of financing the project increases. As evident in Table 2.2, this hypothesis is not rejected. However, it is interesting to notice that although the effect is negative and significant for medium and shallow water depth, it is statistically insignificant for deep water. This can be another sign that the larger companies have less financial constraints in their investment decisions.

VARIABLES	(1)	(2)	(3)	(4)
Past Earnings	0.926***	1.051***	0.795***	0.345**
	(6.776)	(6.159)	(4.316)	(2.615)
Slope of futures curve	0.647***	0.666***	0.653***	0.164
	(4.291)	(2.855)	(3.416)	(0.438)
Cost of capital	-0.083	-0.016	-0.106	-0.149
	(-0.843)	(-0.126)	(-0.983)	(-0.660)
Implied volatility	-0.248	-0.270	-0.262	0.192
	(-1.594)	(-1.221)	(-1.473)	(0.584)
CONTROLS	Y	Y	Y	Y
FIXED EFFECTS	Y	Y	Y	Y
TIME CLUSTERS	Y	Y	Y	Y
# of Observations	790	281	467	42
R-squared	0.757	0.701	0.769	0.829

Robust t-statistics in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 2.3: Estimation results for the North Sea region. Models (1)-(4) correspond to different water depth as follows: (1) All rigs; (2) Shallow water with maximum water depth less than 350 feet; (3) Medium depth with maximum water depth between 4000 feet and 350 feet; and (4) Deep water with maximum water depth more than 4000 feet

Past earnings have a positive effect across all water depth. However, consistent with our hypothesis (4), with an increase in water depth, which coincides with higher concentration of publicly listed companies, the dependence on past earnings decreases. This captures the higher cost of external financing for smaller firms and illustrates the effect of financial friction on firms with lower access to capital. Table 2.5 present the results for the Gulf of Mexico with historical volatilities used as a measure for volatility. The historical volatility is calculated based on the standard deviation of 12 month futures prices over a 30 day window.

VARIABLES	(1)	(2)	(3)	(4)
Past Earnings	0.906***	0.962***	0.874***	0.769***
	(12.903)	(13.099)	(9.798)	(5.143)
Slope of futures curve	0.440***	0.425***	0.465***	0.455***
	(5.077)	(5.080)	(4.560)	(2.823)
Cost of capital	-0.192***	-0.190***	-0.206***	-0.092
	(-4.896)	(-4.998)	(-4.047)	(-1.360)
Implied volatility	-0.056	0.020	-0.249**	0.068
	(-0.613)	(0.201)	(-2.502)	(0.434)
CONTROLS	Y	Y	Y	Y
FIXED EFFECTS	Y	Y	Y	Y
TIME CLUSTERS	Y	Y	Y	Y
# of Observations	7,123	4,211	2,110	802
R-squared	0.865	0.842	0.819	0.856

Robust t-statistics in parentheses
*** p<0.01, ** p<0.05, * p<0.1
Fixed Effects Panel

Table 2.4: Estimation results for the whole world. Models (1)-(4) correspond to different water depth as follows: (1) All rigs; (2) Shallow water with maximum water depth less than 350 feet; (3) Medium depth with maximum water depth between 4000 feet and 350 feet; and (4) Deep water with maximum water depth more than 4000 feet

Table 2.3 present the results for the North Sea which is an petroleum region in Europe, mainly shared between UK and Norway. Similar overall trends can be identified although because of much less observations, the results are less significant.

VARIABLES	(1) All rigs	(2) Shallowwater: max wd <350	(3) medium depth: 4000> max wd > 350	(4) Deep water max wd > 4000
Past Earnings	1.365***	1.551***	1.110***	0.679***
	(11.371)	(10.204)	(9.171)	(3.631)
Oil Price	-0.743***	-0.584***	-0.807***	-1.358***
	(-4.818)	(-3.173)	(-4.466)	(-4.100)
Future 1 Year	1.084***	0.806***	1.334***	2.040***
	(4.996)	(3.219)	(5.712)	(4.289)
Cost of Capital	-0.149***	-0.149***	-0.156***	-0.054
	(-3.767)	(-3.197)	(-3.261)	(-0.787)
Historical Volatility	-0.166***	-0.147**	-0.205***	-0.179**
of Futures Contracts	(-2.871)	(-1.999)	(-4.149)	(-2.412)
CONTROLS	Y	Y	Y	Y
FIXED EFFECTS	Y	Y	Y	Y
TIME CLUSTERS	Y	Y	Y	Y
Observations	3,843	2,456	1,017	370
R-squared	0.884	0.869	0.825	0.822

Robust t-statistics in parentheses,
*** p<0.01, ** p<0.05, * p<0.1
Fixed Effects Panel

Table 2.5: Estimation results for the Gulf of Mexico region with historical volatility. Models (1)-(4) correspond to different water depth as follows: (1) All rigs; (2) Shallow water with maximum water depth <350 feet; (3) Medium depth with maximum water depth between 4000 feet and 350 feet; and (4) Deep water with maximum water depth > 4000 feet,

Table 2.5 presents the results for the whole sample. The coefficients are in general consistent with previous tables. The only noticeable difference is that the implied volatility for medium water has become significant in the complete sample. As discussed earlier, this is mainly due to the increased power of our tests in the presence of more observations.

We repeat our estimation with longer maturity futures contracts such as 24 month and the results are generally similar to 12 month maturity. However, it is important to notice as the maturities become longer, the traded volume decreases and the contracts become less liquid hence the price discovery role of the reported quotes may be diluted.

2.7. CONCLUSION

Unique characteristics of exhaustible natural resources such as irreversibility and exhaustibility necessitate distinctive approaches in evaluating related investment projects. In this paper, real options approach was employed to evaluate investment decisions of oil and gas companies in an empirical setup. Our real options model, though simple, provides powerful insights into the problem and equips us with a theoretical framework.

Data limitations encouraged us to use innovative methods to attack the investment analysis problem, which nonetheless, require some assumptions to bridge between available data and our desired variables. Exploiting the fact that crude oil is a commodity, we assumed that past prices can serve as a proxy for past earnings. Considering the institutional settings in the drilling industry and our equilibrium pricing of the drilling equipment, we are able to construct our panel data model specification.

Our empirical results are generally consistent with our hypothesis. Nonetheless, the effect of uncertainty on the investments of oil and gas companies is not fully captured in our model as expected. Finding better proxies for future uncertainty and better controls, which could increase the power of our tests, remains an open task for future research.

Our theoretical model needs to be expanded to capture more aspects of the investment decisions of oil companies, specifically the effect of financial frictions. Finally, our investment dataset includes up to end of 2010. To have a better picture of the effect of 2008 financial crisis on the investments, we need to obtain updates to our database to include more of the post 2008 crisis so that we can split our sample into two distinct periods, before and after the crisis. We suspect that updated data will give us interesting new insights into the dynamics of offshore investment in petroleum projects.

Chapter 3: Effect of Shale Gas Revolution on U.S. Energy-Intensive Manufacturing

3.1. Introduction

Recent technological advances in natural gas production have made large deposits of untapped natural gas reserves available for extraction, which in turn caused a steep decline in U.S. natural gas prices during past decade. Rapid and unexpected improvements in horizontal drilling and hydraulic fracturing have made natural gas production from huge shale beds economically viable, creating an unprecedented natural gas production boom, often referred to as “Shale Gas Revolution” or “Shale Rush”.

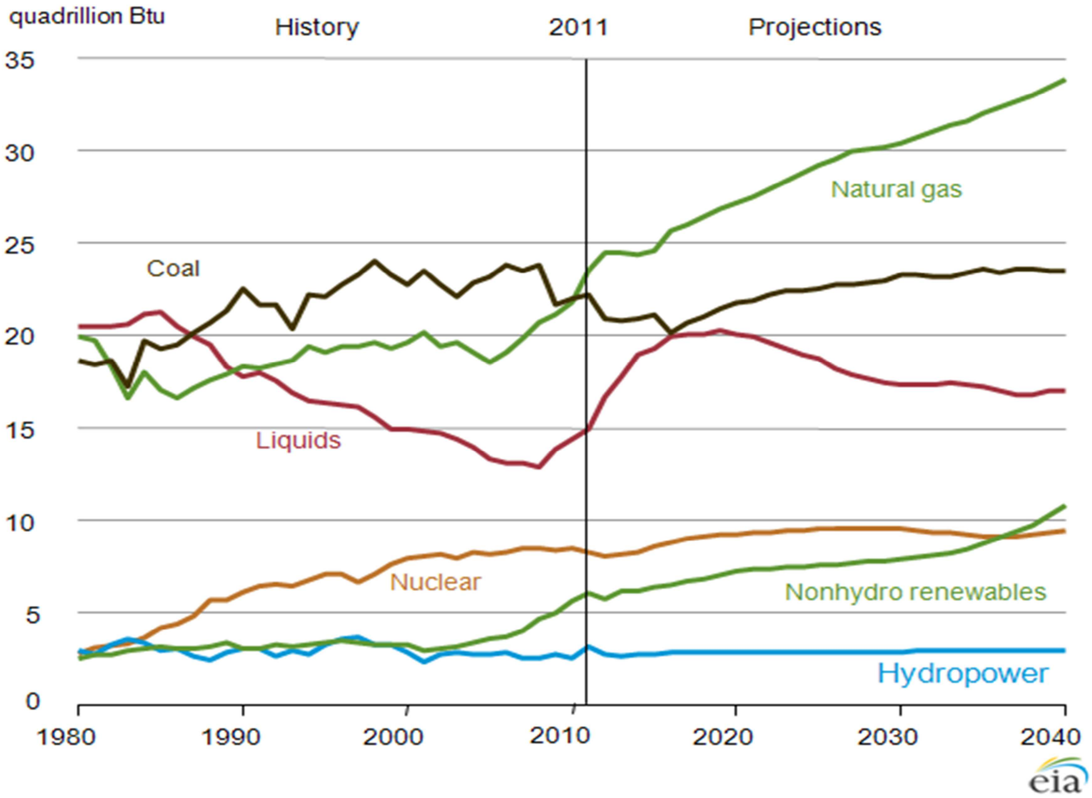

Figure 3.1: U.S. energy production by fuel (1980-2040)

Energy industry experts' estimates of recoverable natural gas in USA, which has been in steady decline during past few decades, have suddenly increased significantly to the point that Energy Information Administration predicts that USA will become a net exporter of natural gas by 2020.

Transportation of natural gas is relatively costly. Unlike crude oil that can be transported via large tankers, natural gas is mostly transported using pipelines or in the form of Liquefied Natural Gas (LNG), both of which require large infrastructural investments. This creates isolated markets in different regions of the world allowing for large price dispersions in different markets. The United States and Canada are connected through a large and geographically broad network of pipelines hence natural gas prices are highly correlated within North America. However, transportation of natural gas across oceans is prohibitively expensive and capital intensive. This makes natural gas markets and its price dynamics completely different from crude oil.

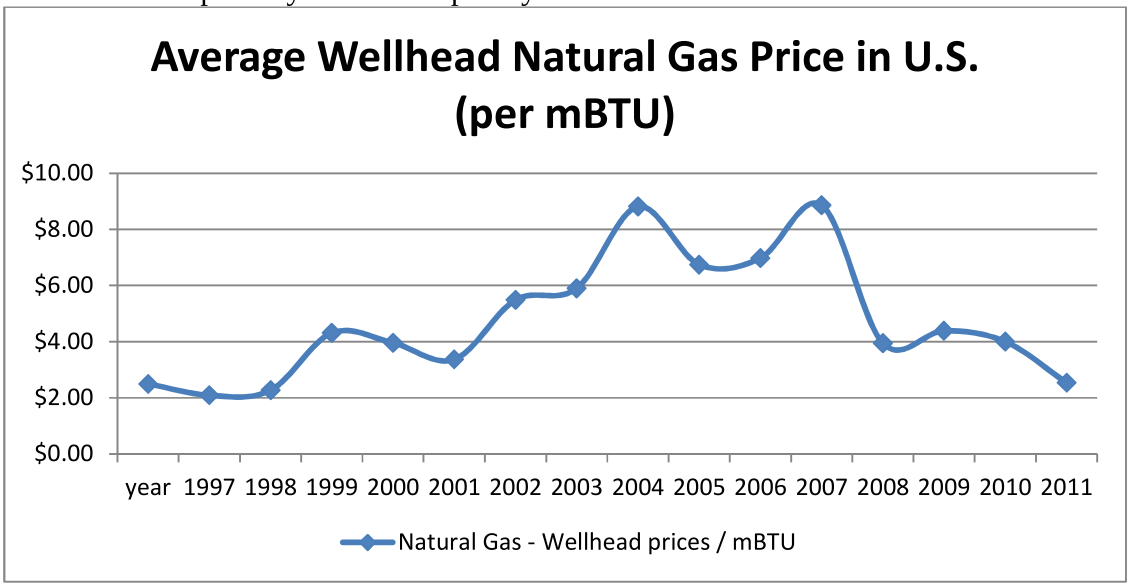

Figure 3.2: Average wellhead natural gas price in U.S. 1996-2011. (Source: EIA)

In contrast to crude oil which has highly correlated prices, natural gas prices may differ significantly across the world. In North America, natural gas sells for around \$4 per million British thermal units (mBTU) while in Europe it costs around \$12 mBTU and it may reach up to \$20 mBTU in Asia. This gap has specially widened recently because of increased shale gas production which caused the prices of natural gas to decline significantly in U.S.

Natural gas serves as a major source of energy for a variety of energy intensive industries such as Iron and steel, rubber and plastic products, foundries, chemical processing units, glass blowing factories and paper production. Wide dispersion of natural gas prices in different regions of the world can become a significant competitive advantage for firms that have access to this input factor at a cheaper rate. These industries have been losing their competitive advantage to countries with low labor cost. Hence, a small cost advantage may increase their competitive advantage and even reverse the offshoring trend of energy intensive industries. A recent report from Boston Consulting Group (BCG), *"U.S. Manufacturing Nears the Tipping Point: Which Industries, Why, and How Much?"* identifies seven industry groups including energy intensive industries such as plastic & rubber products and fabricated metal products that are at a tipping point and may become competitive within United States in near future, given the changing scene of global economy.

Energy intensive manufacturing companies certainly prefer lower natural gas prices, but energy companies are suffering from historically low natural gas prices so they are pushing for obtaining LNG export licenses to benefit from price dispersions between U.S. and the rest of the world, especially Europe and Asia. Obama administration has issued the first such licenses to Cheniere Energy in March 2012, planning to start exporting LNG in 2015. A second license has been issued in June 2013.

The long delay between these two licenses is partly due to debates between opponents and supporters of natural gas exports. If the barriers to export is removed, the U.S. natural gas producers will gain as the prices will get closer to that of Europe and Asia, although it will remain at least $5 lower than any export destination, due to conversion and transportation costs given currently available technologies. The energy intensive industries will clearly lose in this scenario, hence they are fiercely lobbying for restricting LNG export permits to help domestic manufacturing survive global competition, obviously at natural gas producers' loss.

American Chemistry Council (ACC) has recently published two reports about the effect of Shale Gas discoveries on U.S. manufacturing arguing that low natural gas prices will help ailing U.S. manufacturing sector to recover. In *"Shale Gas, Competitiveness and New U.S. Investment: A Case Study of Eight Manufacturing Industries"* ACC concludes that if U.S. natural gas prices continue to remain lower than $5/mBTU, resulting competitive advantage will spur more than $72 billion of new investments in energy intensive manufacturing and 1.2 million new jobs in U.S. over the next decade.

The purpose of this research is to investigate the effect of low natural gas prices on energy intensive U.S. manufacturing industries using widely available data. I empirically evaluate the stock market reactions of publicly traded companies to arrival of new information about the evolution of the cost of an input factor in future, namely 12-month natural gas futures contracts prices.

Futures contracts are signed between two parties for delivery of a specified good at certain point of time in future at agreed upon price. The commodities futures contracts are widely traded and help the two parties avoid price risks or hedge their investments. It also aggregates and reflects the available information in the market about suspected price shocks in the future. For instance, discovery of a new gas reserve that will come on line in two years will be comprehended by the industry experts, who have the knowledge and expertise about the industry. They can predict the effect of the new discovery on prices after the newly discovered reserves start production. As a result, they will have incentive to sell more 2-year futures contracts to lock in higher prices at the maturity date of their contracts. The increased supply of 2-year futures contracts will reduce the prices of these contracts. Hence, assuming that the markets are efficient, any newly available information will be reflected in futures contracts prices. Even non-experts can rely on futures contracts –and the evolution of their prices– as a gauge of what the informed market players believe about the innovation of prices. Thus, futures contracts also play an important role as aggregators of available information in the market.

The buyer of a futures contract may gain or lose because of the arrival of new information. If new natural gas resources are discovered and market players believe that the price of natural gas will decline, the long term contract with a future maturity date will be less valuable hence the buyer will lose from the arrival of new information. Similarly, if new information is revealed indicating that the prices are expected to rise, the value of a futures contract at hand will increase and its owner will gain from expected upward movements in the market.[38]

Both manufacturers and stock market participants who are interested in learning about expected future prices of natural gas but lack the knowledge and expertise to analyze the energy markets in detail, can take note from the evolution of these futures contracts prices. My hypothesis is that if natural gas prices are significant factors in the core competiveness of energy intensive industries, the stock prices of these companies should react negatively to positive price innovations of futures contracts as these positive

[38] The exact amount of return that one obtains from engaging in these contracts will depend on the margin limits for these contracts, which may be variable in different circumstances but are mostly in 5%-10% range.

shocks are indicative of an increase in expected price in future. The direction of the price innovations and their magnitude can be perceived by considering the unanticipated gains/losses in buying these contracts and holding them over time.

To obtain a measure of these unanticipated gains/losses arising from buying natural gas futures contracts, I construct a time series of gains/losses from buying and holding these contracts. If these gains are positive, there has been an unanticipated news in the market regarding the future prices of the underlying commodity, namely natural gas. Hence, the stock market participants can benefit from the information aggregation role of futures markets to learn about the future profitability of energy intensive industries. If the price of natural gas is in fact a substantial element in profitability of these industries, it will in turn be reflected in the stock value of the corresponding companies.

To test this hypothesis, I regress the monthly stock returns of energy intensive industries[39] on the gains/losses from buying 13-month natural gas futures contracts and holding them for one month. I control for Fama-French three factors to account for common risk factors that may affect the stock returns. To better present the effect of natural gas I divide the energy intensive industries into highly energy intensive and moderately energy intensive industries using a measure constructed from estimates by Energy Information Administration and Census Bureau.

The rest of this paper is organized as follows. In section 2, an introduction the institutional setup and background of the research is presented which includes a quick overview of shale gas revolution, the market for natural gas futures contracts and a discussion of energy intensive industries. Section 3 is dedicated to discussing the

[39] I will discuss the selection process of these companies in more detail.

empirical strategy. I describe the data in section 4. The discussion of the results are presented in section 5. Section 6 concludes the paper with some suggestions for extending this research project.

3.2. BACKGROUND AND INSTITUTIONAL SETUP

3.2.1 Shale Gas Revolution

The estimates for total natural gas reserves by Energy Information Administration shows that in 1970's the total natural dry gas reserves in U.S. was around 280 TCF which declined to 160 TCF in 2000. Recent technological advances in natural gas production have made large deposits of untapped natural gas reserves available for extraction hence increasing the total dry natural gas reserves to more than 350 TCF in 2012. This has caused a steep decline in U.S. natural gas prices during past decade. The revolution has been even more astonishing in shale gas reserves. National Petroleum Council's 2003 estimate of technically recoverable shale gas reserves was around 38 trillion cubic feet (TCF) while the lower bound of more recent estimates are around 600 TCF (out of U.S. total natural gas reserves of 2500 TCF).

Unconventional natural gas resources have been geologically present and widely studied. However, the prohibitively high extraction costs have made them economically infeasible to extract given the existing technologies. Rapid and unexpected improvements in horizontal drilling coupled with hydraulic fracturing techniques have made natural gas production from huge shale beds economically viable. The learning curve effect of implementing more and more of these type of production procedures has reduced the extraction costs, bringing in more production on line, creating an unprecedented natural gas production boom, often referred to as "Shale Gas Revolution" or "Shale Rush".

Energy industry experts' estimates of recoverable natural gas in USA, which has been in steady decline during past few decades, have suddenly increased significantly to the point that Energy Information Administration predicts that USA will become a net exporter of natural gas by 2020.

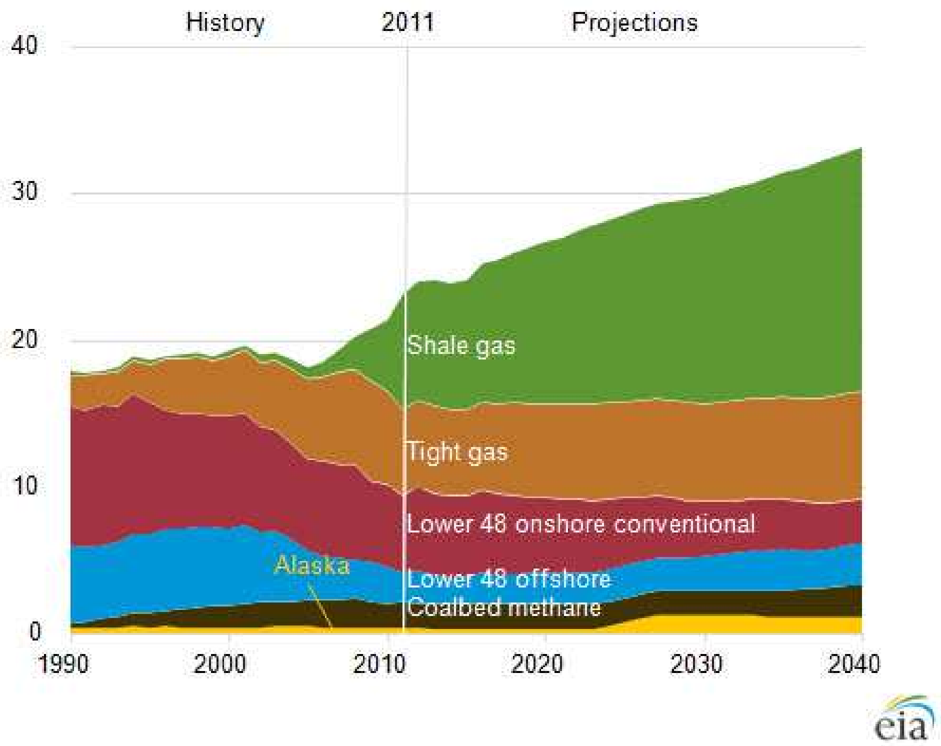

Figure 3.3: Natural Gas Production by Source, 1990-2040 (trillion cubic feet) Source: EIA (2012)

Transportation of natural gas is relatively costly compared to other types of fossil fuels. Unlike crude oil that can be transported via large tankers, natural gas is mostly transported using pipelines or in the form of Liquefied Natural Gas (LNG). The United States and Canada are connected through a large and geographically broad network of pipelines. However, building pipelines require large investment and maintenance costs and is not economically viable for transportation of natural gas across oceans. To overcome this barrier, natural gas exporters (and importers) resort to LNG technology, which requires converting the natural gas into liquid using large compressors. The LNG is then stored in huge high-pressure storage tankers in special carrier ships and transported to destination. The LNG is than converted back into gas at destination ports and connected to the domestic natural gas network of pipelines. All three steps of the LNG exporting procedure require huge investments in the underlying infrastructure. For instance, American corporations have invested more than $200 billion only in Gulf of Mexico LNG importing facilities during past decade. The huge upfront investments required for import/export of natural gas -and its inherently costly procedure- creates relatively isolated markets in different regions of the world. This makes natural gas markets and its price dynamics completely different from crude oil. Different types of crude oil may have different prices in different regions of the world but crude oil prices are often highly correlated. In contrast, natural gas producers often face barriers to entry to other markets; hence price dispersions can be significant in different regions of the world. In North America, natural gas sells for around $4 per million British thermal units (mBTU) while in Europe it costs around $12 mBTU and it may reach up to $20 mBTU in Asia. This gap has specially widened recently because of increased shale gas production, which caused the prices of natural gas to decline significantly in U.S.

The vast number of natural gas producers in U.S. allows for competition so the U.S. natural gas prices are determined competitively and may be highly volatile depending on new discoveries and demand prospects.

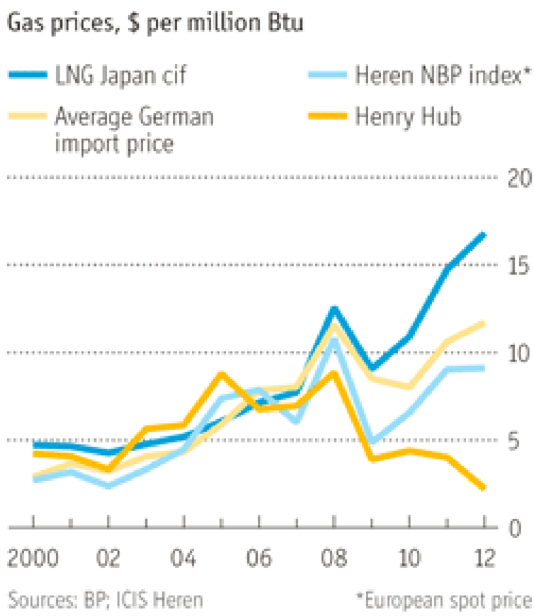

Figure 3.4: Significant price dispersions in different natural gas markets

In contrast, the natural gas market is highly concentrated in Europe, with a large share of its natural gas being imported from Russia via pipelines. Building a pipeline between two countries is a customer-specific investment, which raises special contractual concerns. If any of the two parties decides not to engage in the envisioned trading scheme, the investments on the pipeline will be wasted. To avoid this hold-up problem, the parties involved in natural gas exports/imports usually sign long term contracts, in some cases lasting for decades. Because of the localized markets of natural gas, devising a reasonable pricing mechanism is crucial in designing these long-term contracts. A common approach in long term natural gas contracts is indexing the natural gas price to the price of an specified type of crude oil. For instance, Russia is a major supplier of Europe’s natural gas and the price of its natural gas is mostly indexed to crude oil prices. As a result, natural gas prices in Europe have remained high, in tandem with oil prices, although they have experienced a downward swing in U.S. after increased production from shale resources.

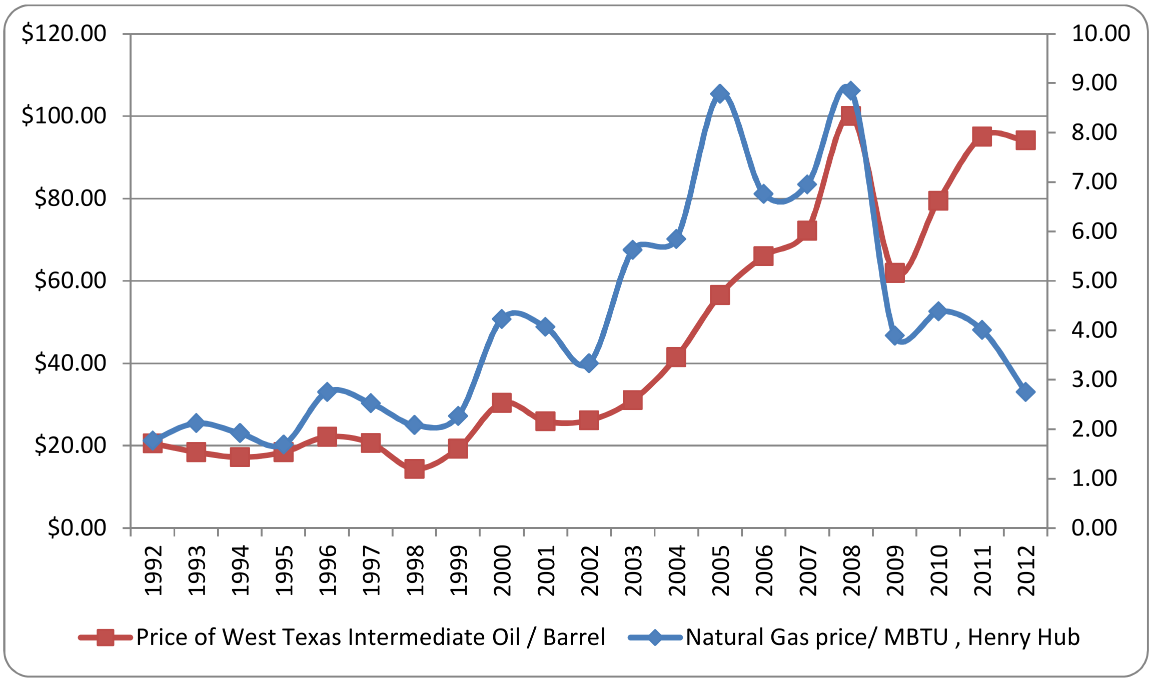

Figure 3.5. divergence between the price of crude oil natural gas after shale gas revolution in US.

3.2.2. Natural Gas Futures Contracts

Futures contracts are signed between two parties for delivery of a specified good at certain point of time in future at agreed upon price. The commodities futures contracts are widely traded and help the two parties hedge their investments. It also aggregates and reflects the available information in the market about suspected price shocks in the future. For instance, discovery of a new gas reserve that will come on line in two years will be comprehended by the industry experts, who have the knowledge and expertise about the industry. They can predict the effect of the new discovery on prices after the newly discovered reserves start production. As a result, they will have incentive to sell more 2-

year futures contracts to lock in higher prices at the maturity date of their contracts. The increased supply of 2-year futures contracts will reduce the prices of these contracts. Hence, assuming that the markets are efficient, any newly available information will be reflected in futures contracts prices. Even non-experts can rely on futures contracts –and the evolution of their prices– as a gauge of what the informed market players believe about the innovation of prices. Thus, futures contracts also play an important role as aggregators of available information in the market.

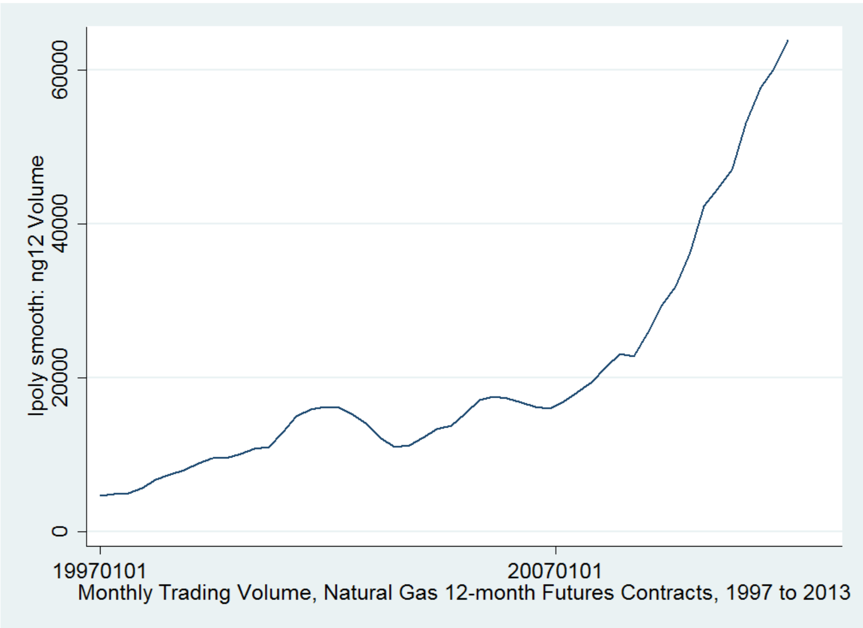

Figure 3.6: Increasing trading volume for natural gas 12-month futures contracts, over time (for delivery at Henry Hub). The trading volume was less than 6000 in each month during early 1990's but has increased to more than 10000 after 2000's and it is growing significantly.

In contrast to crude oil futures contracts that are widely traded across the world, the trading volume in natural gas contracts is significantly lower because of the localized nature of its markets. The natural gas futures contracts in U.S. are mostly traded based on delivery at the Henry Hub in Louisiana, which is the intersection of several interstate natural gas pipelines. Although these contracts have been traded since early 1990s, the trading volume has picked up from late 1990s. Hence, we will restrict our attention to the past 13 years in which trading volumes have been higher than 1000 contracts per month, which roughly corresponds to a daily average of 500 contracts.

The buyer of a futures contract may gain or lose because of the arrival of new information. Consider a buyer who purchases a natural gas futures contract in July 2013 who has agreed to pay $5/mBTU at the delivery date of July 1st 2014. If new natural gas resources are discovered and market players believe that the price of natural gas will decline to $4.8/mBTU in July 2014, the contract with the maturity date of July 2014 will now be worth only $4.8/mBTU but the buyer is committed to pay $5/mBTU hence she will lose $0.2/mBTU. Conversely, assume for instance that export restrictions are removed and prices are expected to rise to $6/mBTU in July 2014, the value of the contract at hand will increase and its owner will gain from expected upward movements in the market.[40]

Both manufacturers and stock market participants who are interested in learning about expected future prices of natural gas but lack the knowledge and expertise to analyze the energy markets in detail, can take note from the evolution of these futures contracts prices. My hypothesis is that if natural gas prices are significant factors in the core competiveness of energy intensive industries, the stock prices of these companies should react negatively to positive price innovations of futures contracts as these positive shocks are indicative of an increase in expected price in future. The direction of the price

[40] The exact amount of return that one obtains from engaging in these contracts will depend on the margin limits for these contracts, which may be variable in different circumstances but are mostly in 5%-10% range.

innovations and their magnitude can be perceived by considering the unanticipated gains/losses in buying these contracts and holding them over time.

To obtain a measure of these unanticipated gains/losses arising from buying natural gas futures contracts, I construct a time series of gains/losses from buying and holding these contracts. Consider an agent who buys a 13-month futures contract at time t and pays f_t^{t+13}. If he holds his/her contract for one month, it will be worth f_{t+1}^{t+13}, because the contract is now equivalent to a 12-month futures contract sold at t+1 and maturing at t+13. The difference between f_t^{t+13} and f_{t+1}^{t+13} will be the one-month gain from engaging in this trading activity. If this gain is positive, there has been an unanticipated news in the market regarding the future prices of the underlying commodity, namely natural gas. Hence, the stock market participants can benefit from the information aggregation role of futures markets to learn about the future profitability of energy intensive industries. If the price of natural gas is in fact a substantial element in profitability of these industries, it will in turn be reflected in the stock value of the corresponding companies.

To test this hypothesis, I regress the monthly stock returns of energy intensive industries on the monthly return of described trading strategies for 13-month natural gas futures contracts. I control for Fama-French three factors to account for common risk factors that may affect the stock returns.

3.2.3. Energy Intensive Industries

According to EIA, energy intensive manufacturing accounts for more than half of total industrial energy use. Energy intensive industries' share of energy use is roughly twice their share of gross output. Recent cheap natural gas prices has spurred investments in energy-intensive industries and increased the share of energy intensive industries. These industries may use different sources of energy such as electricity, coal, oil or natural gas. However, natural gas is one of the most important sources. According to the Department of Energy (2009), the source of 40% of total industrial energy consumption is natural gas.

In addition to industries that use natural gas as their major source of energy, there are some industries that are positively affected by shale gas revolution because they rely on ethane, propane which are by products of natural gas and their abundant supply has caused their prices to decline in tandem with natural gas.

There are different classifications of energy intensive industries by different sources. I use the classification by American Chemistry Council (2012) to obtain the list of these industries as presented in table 3.1. They include 7 major industry groups including Paper, Chemicals (excluding Pharmaceuticals), Plastic & Rubber Products, Glass, Iron and Steel, Aluminum and Fabricated Metal Products. After identifying these broad categories, I used the Fama French 49 industries classification to narrow down the list of SIC codes. I then manually went through the list of 4-digit Standardized Industry Classifications to identify corresponding SIC codes. I then used the list of these SIC codes to download relevant companies’ stock market data from Wharton Research Data Services (WRDS).

Industry	Fama French portfolios	4-digit SIC code
Paper	Building paper and board mills Paper and allied products Paper and allied products Manifold business forms Paperboard containers, boxes,	2600-2639 2640-2659 2670-2699 2660-2661 2760-2761
Chemicals (excluding Pharmaceuticals)	Chemicals and allied products Industrial inorganical chemistry Plastic material & synthetic resin Paints Industrial organic chemistry Agriculture chemicals	2800-2809 2810-2819 2820-2829 2850-2859 2860-2869 2870-2879
Plastic & Rubber Products	Reclaimed rubber Rubber & plastic hose and belting Gaskets, hoses, etc Fabricated rubber products	3031-3031 3041-3041 3050-3053 3060-3069 3070-3079
Glass	Pressed and blown glass Glass products Flat glass Glass containers	3229-3229 3230-3231 3210-3211 3220-3221
Iron and Steel	Primary metal industries Blast furnaces & steel works Iron & steel foundries Prim smelt-refinery nonferrous metals Secondary smelt-refinery nonferrous metals Rolling & drawing nonferrous metals Non-ferrous foundries and casting Steel works etc Misc primary metal products	3300-3300 3310-3317 3320-3325 3330-3339 3340-3341 3350-3357 3360-3369 3370-3379 3390-3399
Aluminum	Bauxite and other aluminum ores	1050-1059
Fabricated Metal Products	Fabricated metal, except machinery Fabricated plate work Sheet metal work Metal forgings and stampings Coating and engraving Metal cans and shipping containers	3400-3400 3443-3443 3444-3444 3460-3469 3470-3479 3410-3412

Table 3.1 list of energy intensive industries and corresponding 4 digit SIC codes

To better present the effect of natural gas on industries with different levels on energy intensity, I divide the energy intensive industries into highly energy intensive and moderately energy intensive industries using a measure constructed from estimates by Energy Information Administration and Census Bureau. These measure are presented in Table 3.2. and obtained as follows. The total natural gas consumption in each industry is obtained from EIA and is presented in second column. The total shipment value of the products in these industries which roughly corresponds to their sales is obtained from the Census Bureau. Finally, the ratio of natural gas costs to total sales of the industry is calculated assuming an average delivery price of $8/MCF to industrial consumers.

Industry	Natural gas consumption, based on EIA estimates, 2012 (BCF)	Total shipment based on Census Bureau, 2012 ($billion)	Natural gas share (% of industry energy use)	Additional output based on ACC estimates ($billion)	Natural Gas Intensity Index: ratio natural gas expenditure from total sales (2012)
Paper	460	170.2	20	$3.70	2%
Chemicals (excluding Pharmaceuticals)	1700	483.6	33	70	2%
Plastic & Rubber Products	125	186	38	33	0.5%
Glass	150	20	53	0.66	6%
Iron and Steel	375	114	35	5	3%
Aluminum	180	22	49	1.69	3%
Foundries	120	26	44	0.62	4%
Fabricated Metal Products	235	327	61	5.81	0.6%

Table 3.2. Energy Intensity Index. Source: EIA and Census Bureau

3.3. EMPIRICAL STRATEGY

I empirically evaluate the stock market reactions of publicly traded companies in energy intensive industries to arrival of new information about the evolution of the cost of an input factor in future. To test this hypothesis, I regress the monthly stock returns of companies in energy intensive industries[41] on the gains/losses from buying 13-month natural gas futures contracts and holding them for one month. I control for Fama-French three factors to account for common risk factors that may affect the stock returns.

$$R_i = \alpha + \beta\left(R_m - R_f\right) + \beta_{SMB}\, SMB + \beta_{HML}\, HML + NGR + \epsilon \qquad (3.1)$$

where R_i is the monthly excess return (over risk free rate) of ith stock, $R_m - R_f$ is the monthly excess return of market over risk free rate, SMB is the difference between the return of the small cap stocks and large cap stocks, HML is the difference between high book-to-market ratio stocks and low book-to-market ratio stocks and NGR measures the innovations in future natural gas prices. The first three variables are Fama-French proposed risk factors and NGR is the difference between the 13-month futures contracts at the beginning of previous month and the 12 month futures contracts at present normalized by the 12 month futures contracts at present.

$$NGR_t = (f_{t-1}^{t+12} - f_t^{t+12}) / \, f_{t-1}^{t+12} \qquad (3.2)$$

where f_τ^t is the futures contract signed at time τ for delivery at time t and captures the gain from buying a 13 month natural gas futures contract during the last month and holding it for one period.

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[41] I have discussed the selection process of these companies in more detail in previous section.

To better present the effect of natural gas I divide the energy intensive industries into 2 distinct groups based on a measure I develop for the level of their dependence on natural gas. Define

$$NG_{intensity} = \frac{natural\ gas\ consumption * natural\ gas\ price}{Value\ of\ shipments} \qquad (3.3)$$

$Ng_{intnsity}$ measures the ratio of total sales to total money spent on natural gas consumption. We can define an indicator based on this measure which takes the value of 1 when an industry consumes high gas volumes compared to its total sales and takes o otherwise.

$$sNG = \begin{cases} 1 & if\ NG_{intensity} \geq 4\% \\ 0 & otherwise \end{cases} \qquad (3.4)$$

We can run separate regressions for highly gas intensive industries and low gas intensive ones to be able to compare the sensitivities of these industries to changes in gas prices.

3.4. DATA

This section is dedicated to describing the data that I use in my statistical analysis. The time window of our analysis is restricted by the trading volume of natural gas futures contracts which have been very low in 1990s. Hence I pick the January 2000 to present as my time window of analysis.

I obtained both the prices and trading volume of the futures contracts for natural gas from Bloomberg Terminal on a monthly basis from January 2000 to April 2013. The natural gas futures prices are quoted for delivery at Henry Hub in Louisiana.

The stock market data is obtained from CRSP through Wharton Research Data Services (WRDS). The universe of companies is restricted to all those that had one of their Standard International Classification Codes listed as energy intensive industries SIC4 (Table 3.1).

The monthly Fama-French three factors are available from Kenneth French's website.[42] The Fama French 49 industries classification is also obtained from the same website as a guideline for finding energy intensive industries, although not explicitly used in empirical analysis.

Natural gas prices are obtained from the Energy Information Administration (EIA)[43] portal for natural gas data. The industry sector revenue used for calculations of energy intensity index is also obtained from ACC (2012) which has in turn been gathered from the Census Bureau.

3.5. ESTIMATION RESULTS

The regression results are presented in this section. The model specification described in equation (3.1) is estimated. After observations with missing variables and implausible figures are dropped, there are in total 75571 month-firm observations in our sample.

There are multiple observations at any time period, corresponding to different companies. The stock market valuation of these stocks may be correlated across firms. Hence, the estimated standard errors may become higher than their true values if we do not address the correlation within each time period. To deal with this problem with cluster our observations at each point of time, allowing for correlation of error terms within each time period.

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[42] http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/Data_Library/

[43] http://www.eia.gov/naturalgas/data.cfm

The estimation results are presented in Table 3.3. We expect that positive shocks to futures prices of natural gas should have a negative effect on the stock returns of the energy intensive industries. Column 1 demonstrates the regression results for all energy intensive industries in our sample. In contrast to our expectation, the estimated coefficient for natural gas positive price shocks is positive though insignificant. We can conclude that price innovations in natural gas prices do not have a significant effect on profitability of energy intensive companies. This result has important implications as it shows that contrary to claims of natural gas exports critics, the competitiveness of the companies in these industries is not highly dependent on future gas prices.

Excess Return	(1) All Energy Intensive Industries	(2) High Gas Intensity industries	(3) Low Gas Intensity industries
Market-RF	0.965***	0.917***	0.975***
	(3.618)	(3.540)	(3.628)
HML	0.576	0.625*	0.571
	(1.494)	(1.672)	(1.472)
SMB	1.213***	1.324***	1.196***
	(3.434)	(3.942)	(3.351)
NGR	0.184	-0.282*	0.255*
	(1.194)	(-1.800)	(1.652)
Observations	75,429	10,145	65,284
R-squared	0.060	0.073	0.062

Robust t-statistics in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 3.3. Estimation Results: Effect of Natural Gas Futures on Market Return for different energy intensity case. Model (1) includes all energy intensive industries in U.S. Model (2) includes only industries with high natural gas intensity. The third column includes only firms with low natural gas intensity.

I split the sample into two groups, as described in the previous section, based on the ratio of their natural gas expenditure to their total sales. I call the industries with high spending levels on natural gas “high gas intensity industries” and the rest of the sample as “low gas intensity industries”. The estimation results for these two groups is presented in columns (2) and (3) of Table 3.3. The sample size for highly energy intensive industries is reduced to 9020 observations. Although the coefficients on other control variables are not affected substantially, the coefficient on NGR becomes significant and negative. It is important to notice that NGR is the rate of change between two futures contracts initiated in different dates but with the same maturity dates. This implies that a one percent change in natural gas futures contracts will cause the return on the stocks of gas intensive companies to decline by 0.28% after controlling for other risk factors that may affect the stock returns.

3.6. Conclusions and Extensions

New extraction technologies have made U.S. natural gas production from vast shale gas resources possible. The increased natural gas production reduced prices and kept them at a low level, which benefited energy intensive manufacturing industries. Debates about whether the government should allow natural gas exports or restrict it to keep prices low, have been pursued fiercely by both energy intensive industries and natural gas producers.

Shale gas has undoubtedly changed the global scene for the future of natural gas production in both in U.S. and the world. It will definitely affect overall U.S. competitiveness positively. However, this research empirically tests and documents that its role and importance is often exaggerated. In this research, I focused on the stock market reactions of companies in energy intensive industries to the unexpected price shocks in natural gas futures markets. My results show that stock markets do not react significantly to innovations in the expected price of natural gas, proxied for by natural gas futures contracts. This implies that either the effect is weak or that the market participants fail to incorporate the arriving information into their valuation of corresponding companies.

To better differentiate these effects for those industries that are highly dependent on natural gas from those that may be less energy intensive or more dependent on other forms of energy, I used a measure for natural gas intensity based on the ratio of natural gas expenditure to the size of the industry. The results show that the stock market value of more gas intensive industries are indeed negatively affected by upward innovations in natural gas prices and the rest of the industries do not show a significant reaction. This observation shows that although the cheaper natural gas prices may give substantial competitive advantage to a small group of U.S. manufacturing sector, the effect is not widespread enough to justify restricting natural gas exports especially since the price gap between U.S. and other parts of the world has been widening in recent years.

This research can be extended in several directions. One possible extension is to incorporate the past investment activity of energy intensive industries in our empirical analysis. Firms that have invested heavily in gas intensive industries should be more inclined to respond more severely to natural gas price shocks, which will be reflected in the monthly return of corresponding stocks.

A further step into evaluating the effect of long term cheap natural gas on energy intensive manufacturing will be to analyze the reverse channel, investigating how cheap natural gas has fostered investment. The main obstacle in implementing this approach is to pick the right control group for comparison. The best candidate is to select a group of similar companies outside U.S. that face higher natural gas prices but compete with U.S. companies in the same markets globally. The main constraint is to find the comparable and consistent measures on investment activity between companies inside and outside U.S. because datasets such as COMPUSTAT report different items for U.S. companies and global companies and the researchers should explore other alternatives to find suitable measures for investment activity.

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Vita

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