Risk Management and Capital Budgeting: Evidence from Project-Level Discount Rate *

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Abstract

I use a detailed and comprehensive project-level dataset to investigate how managers assess project risks. Exploiting a revealed preference strategy, I extract firms' project-specific implied discount rate and examine if their behavior is consistent with core corporate finance predictions. Using variation in the level of their potential projects' idiosyncratic risk, I document that, on average, firms inflate their discount rate in projects facing a high level of idiosyncratic risk. In a second step, I document a channel - firm hierarchical structure - that affects how managers price idiosyncratic risk.

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Classical corporate finance theory dictates that the discount rate should only account for the systematic risk component of a firm's investment opportunities, dismissing the idiosyncratic risk. Many warn about the temptation of incorporating a fudge factor in the calculation of the discount rate to account for idiosyncratic risk (e.g. **?**), because of the potentially significant allocation distortion. However, this contrasts with what often happens in practice. Indeed, survey results of the Association for Financial Professionals (AFP) showed that nearly half of their respondents confessed to manually adjusting their discount rate to account for a project's specific risk[1]. When asked, managers of all firm sizes reported using discount rates that are systematically and substantially greater than their cost of capital (**???**). These revelations are worrisome considering that even small deviations from the *true* discount rate can have sizable effects on managers' decisions to pursue a given project[2]. Yet, the empirical literature investigating managers' behavior on the topic remains scarce. In this light, providing empirical evidence on how managers assess idiosyncratic risk when computing the discount rate and the factors affecting the computation is a first-order problem.

In this paper, I use a detailed and comprehensive project-level dataset to investigate how managers assess project risk. Exploiting a revealed preference strategy, I extract firms' project-specific implied discount rate. To obtain an estimate of firms' discount rate, I proceed in two steps. First, I use the internal rate of return (IRR) rule to estimate the discount rate estimate of each project. Second, I restrict the analysis to a subsample of the observations that capture the features of the firm discount rate. To the best of my knowledge, this study is the first to provide direct empirical evidence on how managers compute their projects' discount rate and the potential forces affecting the calculation.

In the first part, I examine whether managers' behavior is consistent with core corporate finance predictions regarding the role of idiosyncratic risk in computing the discount rate. Using variation in the level of idiosyncratic risk in their potential projects, I document that, on average, firms inflate their discount rate in projects facing a high level of idiosyncratic risk, contrary to the prediction of traditional corporate finance theory.

[1] (**?**)

[2] For example, fudging an annual perpetuity true discount rate from 10% to an artificially inflated rate of 11% would decrease the project's cash flow present value by 10%, potentially altering the manager's investment decision.

In the second part of this paper, I identify a channel that affects how managers price idiosyncratic risk, specifically firms' hierarchical structure, and document that delegating investment decisions has an economically significant impact on the price of idiosyncratic risk. Given the growing literature indicating that within-firm delegation processes have a sizable effect on resource allocation (e.g. **???**), firms' hierarchy constitutes a plausible channel.

Measuring firms' project-specific discount rate is empirically challenging; firms do not report this information. Alternatively, extracting this information from firms' investment decisions comes with multiple complications. First, it is not usually possible to observe specific firms' individual investment opportunities and investment decisions. Second, it is generally difficult to compare the opportunity set across and within firms, limiting researchers' ability to properly control for all the potential unobservable factors that could impact the discount rate calculation. Finally, obtaining precise estimates of the managers expected cash flow is rarely possible. Capitalizing on the rich level of details in my dataset and the vast literature on project-level forecasting techniques in the industry analyzed in this paper, I obtain plausible expected cash flow for each investment opportunities.

This study uses the universe of onshore oil and gas wells drilled in the United States from 1983 to 2005, roughly $306 billion in capital projects. The specific nature of this environment enables me to make important progress on issues that previously limited researchers. Specifically, the institutional setting enables me to observe the projects' cash flows and capital expenditures, and to fully characterize each firm's investment portfolio annually. In addition, the projects are homogeneous and tend to be generic, thus providing a large set of uniform observations facilitating the comparison across projects. Since each project in a given period has the exact same exposure to systematic risk from an ex-ante project-level perspective, all differences in discount rate ought to come from other potential distortions, such as the idiosyncratic risk. Effectively, the projects systematic exposure is mainly driven by the resource price variation. Second, the production function of the projects is transparent, which facilitates the computation of the projects' expected quantities.

This paper relates to several streams of research in corporate finance.

First, it contributes to the empirical literature on capital budgeting. **?**, **?**, and **?** provide survey evidence on firms' capital budgeting practices, indicating that more than 90% of managers use either the capital asset pricing model (CAPM) or the internal rate of return (IRR) when deciding which projects to pursue. Additionally, it provides a partial answer to the puzzling large gap between firms' observed weighted cost of capital (WACC) and the managers' effective discount rate raised in **?**. I show that the presence of project-level idiosyncratic risk has an economically significant effect on the size of the project's discount rate.

Second, this paper contributes to the micro-level empirical literature investigating the nature and role of firms' internal allocation mechanisms. Closely related to this paper, **?** shows that firms improperly adjust their discount rate to account for the systematic risk exposure of their different investment opportunities, leading to sizable distortion in the optimal allocation process. In contrast, I study the internal allocation mechanism within a firm division, rather than across divisions. Finally, while their paper focuses on the role of systematic risk exposure on firms' internal resource allocation, I focus on the role of idiosyncratic risk.

Third, according to the Modigliani-Miller paradigm, managers should not be concerned about projects' idiosyncratic risk, since individual investors can easily diversify away their exposure to this source of risk. This contrasts with a vast literature that evaluates how firms' boundaries mediate capital market imperfection (**?**, **?** among others). Theories focusing on the role of firms' internal capital market on optimal resource allocation have produced conflicting results. Some studies suggest that there are positive effects because managers have more information than the market (**?**). However, some authors (**??**) suggest that managerial socialist concern could have a negative effect on the optimal allocation of capital.

Equally, a large literature has produced results suggesting that firms' internal structure - firm hierarchy - plays a critical role in the optimal allocation of resources. On one hand, theoretical work by **?** suggests that delegating investment decision making to the agents with the highest amount of information regarding a specific decision improves resource allocation. This increases the likelihood that people most familiar with investment-specific details will make the decision with limited interference. Recent empirical results indicate that the intensity of the delegation between senior managers and junior managers increases with the amount of specific information required to make the investment decision (?). On the other hand, strong decoupling between the capital allocation and the investment decision might lead to a misalignment of incentives between the different levels of management (?). This could have a deleterious effect on the efficient allocation of resources. In this paper I investigate these two competing views, looking specifically at the consequences of capital allocation by senior managers across multiple oil and gas fields [see figure 1]. When senior managers allocate the budget across multiple oil and gas fields, field managers' idiosyncratic risk exposure to a specific project realization is greater than that of senior managers. As a field manager's budget increases, his exposure to a single well realization decreases. Consequently, a field manager's price of idiosyncratic risk should depend in part on his ability to diversify that risk away.

Finally, while most of the literature on firm risk-taking behavior is centered on how managers shift the riskiness of the investment portfolio, this paper focuses on the effect of firms' hierarchical structure on managers' price of idiosyncratic risk.

1 Oil & Gas Industry: Institutional Background

The commercial life cycle of oil and gas formation is in two stages: (1) the exploration stage, and (2) the development stage. According to the *U.S. Energy Information Agency*, the exploration stage first documents the geological potential of the field and its economic viability. Once firms have sufficient information to confirm the economic potential of the field, it is classified as a proven reserve[3] and the development stage begins. In the development stage, firms still face a high level of idiosyncratic risk such as knowing (1) the exact

[3] Definition for proven reserves: The amount of oil and gas is estimated with reasonable certainty to be economically producible, source: `https://www.americanbar.org/content/dam/aba/publications/litigation_committees/energy/glossary-oil-gas-terms.authcheckdam.pdf`

delineation of the oil field, (2) the structure of the rock formation, (3) the expectation over the production potential of each drilling location, and, (4) the technical expertise required to optimally extract the resource. For example, in figure 2, we see the development of the Panhandle oil field in Texas over the years 1960 to 2010. Figure 2.1 represents the initial estimation of the field boundary, while figure 2.2 represents the realized boundary of the field. There are notable differences between the expected and the realized boundary of the field. Additionally, looking at figures 2.3 to 2.5, it is possible to observe that firms have difficulty finding the best drilling area. The blue circle shows the region of the field where initial wells were drilled but no further development was done because wells performance was poor. Alternatively, the red circle identifies a region with high drilling success. These contrasting examples provide a clear illustration of how idiosyncratic risk remains at the micro-level, although the field potential has been confirmed at the macro-level.

In this paper, I focus on the development stage. During this stage, firms have sufficient information to have reasonable expectation over the production of the field in general but still face a high amount of idiosyncratic risk about the potential of a specific location within the field. However, this idiosyncratic risk steadily declines as firms exploit the field; they learn about the local specific potential and ultimately obtain more granular and precise information. A salient example of how learning translates into lower idiosyncratic risk relates to the probability of drilling a dry hole, a well incapable of economically producing oil or gas[4]. There is a 27.6% probability of drilling a dry hole in the first half of a field development, compared to a 12.1% in the latter half [see table 1][5]. This indicates that wells drilled in the earlier portion of the development stage are 228% more likely to result in a dry hole, a substantial difference. The risk of dry hole depicted in this section nicely echoes the main example of idiosyncratic risk presented in (?, Chap.9, p.235), where the authors refer to the probability of drilling a dry hole as being a diversifiable risk that should not be included in the discount rate calculation.

[4]Definition from the American Bar Association

[5] These statistics are consistent with the unconditional probability of drilling a dry hole reported by the EIA agency.

2 Data

I use a dataset provided by DrillingInfo[6] covering the universe of onshore oil and gas wells drilled in the United States for the period ranging from 1983 to 2005 [see figure 3]. This dataset includes the monthly production of each project and a set of project characteristics such as the rock formation and the depth of the well. To obtain drilling cost estimates, I augment the dataset with a hand-collected set of project capital expenditures, which include the overall drilling cost and the estimated operational costs. Also, I augment this dataset with a hand-collected sample from the EIA of long-term oil and gas price forecasts, the NYMEX oil and gas futures contracts, and the regional spot prices. The EIA is a federal reporting agency producing an annual economic analysis for the oil and gas industry[7].

For a well to be included in the analysis, I require that the firm-year portfolio contains at least 10 wells drilled. Equivalently, for a field to be included in the analysis, there must be at least 10 wells drilled. Finally, I drop the wells with missing fields used in the analysis. Ultimately, the dataset contains 187,107,732 month-well observations used to estimate the well production function for a total of 344,729 distinct oil or gas wells.

Firms in the sample are relatively large, with on average 230 wells drilled over the entire period and 44 wells drilled per year. Considering that drilling a well costs on average \$608,908, these firms' average drilling budget roughly translates to \$26,5 million per year, and total \$139,7 million in value [see table 2]. Also, firms in the sample operate in multiple rock formations, where the average firms are active in roughly 24 fields over the sample period. Additionally, fields in the sample are large, with the average field totaling 466 wells over its lifetime, which corresponds to an average total investment of \$283,6 million. Finally, over the average field commercial life 45 firms will drill wells to extract the resource. Put together, these numbers indicate

[6]DrillingInfo is a trusted data provider from multiple federal agencies reporting on environment and energy matters. Studies conducted by the U.S. Environmental Protection Agency (EPA) and the U.S. Energy Information Administration (EIA) *Inventory of U.S. Greenhouse gas emissions and Sinks, 1990-2016* by the EPA and *Petroleum Supply Monthly (PSM)* by the EIA, for example.

[7]The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. EIA is the nation's premier source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. government. Source: `https://www.eia.gov/about/mission_overview.php`

that firms in my sample are large and well diversified at the firm level, and that multiple firms operate in the fields investigated in this study.

3 Methodology: Revealed Preference

Inferring agent unobservable characteristics through revealed preference is a well-established strategy in economics but it comes with a set of caveats. The main issue relates to the distinction between the agent's normative preference (the agent's actual interests) and the observed revealed preference (the agent's interests that rationalize the observed actions). Multiple factors can affect the disparity between the two preferences, notably (1) the nature of the decision process (active versus passive decision-making), (2) the complexity of the decision rule, and, (3) the agent's experience (**?**). In this study, firms actively make the decision to invest in projects that maximize the net present value (NPV), a simple decision rule. Firms in the sample drill on average 16 wells per year, indicating a substantial level of experience, and they can access information on the outcomes of their competitors' wells from publicly available sources (**?**).

To obtain an estimate of firms' discount rate, I proceed in two steps. First, I use the internal rate of return (IRR) rule to translate the discount rate estimate of each project into a regression framework. Second, I restrict the analysis to a subsample of the observations that capture the features of the firm discount rate.

3.1 Estimating Projects' Internal Rate of Return

First, I compute the implied IRR (μ_i) of each project for firm "i" on year "n" such that:

$$\mathbb{E}[\sum_{t=1}^{T} \frac{1}{(1+\mu)^t} \tilde{Q}_{i,t}] P_i - C_i = 0 \tag{1}$$

Where μ_i corresponds to the projects' monthly expected rate of return (i.e. the project IRR), $\tilde{Q}_{i,t}$ corresponds to the monthly production for well "i" at age "t" months adjusted for the probability of a well having no production (i.e. $Q_{i,t}$ * (1-P(No production))). P_i corresponds to the price the manager will receive net of the operational cost (20%) and royalty rate (18.5%)[8], and C_i corresponds to the initial drilling cost incurred when the well is drilled. Finally, the average well in my sample will produce for 224 months (i.e. T=224).

Calculating projects' IRR can, in some situations, have complications. First, if the projects' cash flows change sign multiple times during the projects' life cycle, it is possible that I obtain multiple estimates of the IRR. Fortunately, wells' cash flow patterns are such that there is one negative cash flow at the beginning of the projects' life, followed by a stream of costs that are proportional to the project revenue flow. Thus, this issue should not affect my IRR calculation. Second, an important critic of the IRR calculation pertains to the project scale. Precisely, it is argued that managers should not solely base their investment decision of the expected IRR, but also on the project size. However, projects in the sample are highly homogeneous and generic, such that drilling costs are similar across projects for a given time period. Figure 4 illustrates that total drilling costs are almost exclusively driven by the wells' depth. For this reason, it is unlikely that such an issue affects the validity of the IRR estimation.

3.2 Estimating Firm-Year discount rate

The strategy used in the first step produces the implied IRR for all the wells drilled for a given firm-year. However, the expected projects' returns often exceed the minimum rate of return set by the firm: the discount rate. For example, oil firms might discover regions with exceptional potential, such that the yield of each project drilled there will far exceed the minimum investment requirement [see figure 5.1]. Managers should invest in all the projects for which the expected return is above their discount rate and avoid investing in projects with poor expected returns. In this study, I only observe the entire set of completed projects for each firm in a given year. In other words, I observe a truncated version of the distribution of projects' returns [see figure 5.2]. In this situation, estimating the firm-year discount rate is equivalent to estimating the truncation threshold of that distribution, the dotted line of figure 5.2, to find the lowest expected rate of return the managers require for a project.

[8] P_i = Oil Price * (1- Royalty - Operational Cost)

However, I do not observe the managers' expectation perfectly, their expectation estimates likely include measurement error. This measurement error affects the truncated distribution of returns I effectively observe as schematized in figure 6. To obtain a reasonable estimate of the firm-year discount rate, I need to define an interval of the distribution to approximate the firm-year effective discount rate, such as the dotted lines in figure 6. This approach enables me to approximate the firm marginal discount rate: the expected rate of return on the least productive project the firm decided to complete. Put differently, I find a proxy for the lowest project's IRR that the firm was willing to take in that given year such that $r \in [p_{k^{th}}, p_{k+n^{th}}]$, where r is the estimate firm-year discount rate, and $p_{k^{th}}$ corresponds to a percentile of the IRR (μ) distribution.

4 Firms' Expectation

To recover an estimate of the project expected discount rate, I need to have the firms' expectation over the project production level (i.e. the number of barrels of oil extracted each month) and the prices at which they will be able to sell their product, the oil or gas prices.

In general, computing the expected quantities independently from expected prices leads to potential biases. In most economics situations the expected production flow of the project is correlated with prices [9]. However, in this specific situation, once the decision to drill has been made, the wells' level production flow does not depend on the state of the market. Rather, expected wells' production flow equation depends on time-invariant local geophysical parameters (i.e. the rock type, viscosity of the resource, etc.). For this reason, the wells' production flow should not be correlated with the variables moving oil prices, making the variation of a given well's production flow independent from the fluctuation in oil prices. Thus, I can independently estimate the expected prices and the quantities.

[9] $E[P_t \cdot Q_{i,t}] = Cov(P_t, Q_{i,t}) + E[P_t] \cdot E[Q_{i,t}]$

4.1 Expected Quantities

4.1.1 Type of Wells and Production Evaluation

We can broadly break down the types of wells drilled in the United States into two categories: (1) vertical and, (2) horizontal wells [see figure 7]. Vertical wells represent a much simpler type of project, they require a more limited set of inputs and have a simpler production function. For this reason, it is easier to generate reasonable expected production level and drilling cost, in comparison to the horizontal wells. Thus, I restrict my sample to all the vertical wells drilled in America, excluding the horizontal wells.

Vertical wells drilled during the sample period share a set of characteristics making them perfect candidates for the type of analysis conducted in this study.

First, the production function (i.e. the monthly production of the wells) can be approximated using a petroleum-engineering model such as the Arp model (**??**). The Arp model is the classical production-forecasting equation, and nowadays it is taught in most energy engineering courses (e.g. Engineering in Oil, Gas and Coal course (Penn ENGR 503)). Using the Arp model, one can compute the well-predicted monthly quantities such that:

$$q_{t,i} = A_i(1 + b\theta t)^{\frac{-1}{b}}$$

Where $q_{t,i}$ is the well's monthly production level (e.g. the monthly production of oil or gas for well "i" at age "t" month), A_i is the baseline production level, and b and β are two decline rate elasticity parameters, and t is the number of months since the well has been drilled. The production baseline, A_i, represents the well initial quantities of oil or gas initially produced by the well. It is conditioned on a firm-year "j", and a region-year "k" fixed effect such that $A_i = A_j + A_k$[10]. I determine the region using a regional cluster strategy based on the wells' latitude and longitude. This is an intuitive choice since wells that are geographically close mostly share

[10]To estimate the production function, I linearize the equation. See Appendix I for more detail on the linearization strategy.

the same geophysical attributes (e.g. quantity of oil available, type of rock, etc.). Identifying oil & gas-rich producing regions via cluster analysis, a machine learning technique, has recently gained traction among academic and practitioners in the oil & gas industry (See **??** among others). Effectively, oil experts are looking for a geographic cluster of rocks with similar characteristics to identify the potential of the rock formation.

Second, I distinctly estimate the decline rate for both oil and gas wells, using a sample of 187,107,732 month-well observations[11]. Figure 8 provides a graphical illustration for the median well production function over time and contrasts it with the estimated production output. Clearly, the estimates convincingly reproduce the production patterns for the median well.

Finally, I use the estimated well production function parameters to obtain an estimate of the managers' wells' production. A striking feature of oil and gas production function pertains to the depletion rate. Since the speed at which the oil or gas is produced depends heavily on geophysical parameters, such as pressure in the natural reservoir (i.e. the depletion rate is not constant over time for a given well) [see figure 8]. Effectively, the pressure is greater in the early moment of the well, making the depletion rate steadily decline over time.

4.1.2 Expected Price

I measure the expected oil and gas prices using the EIA oil and gas price forecast[12]. The EIA price forecast is closely followed by governmental organization, financial institutions, and energy companies. Considering that the discounted projects' half-life[13] in my sample is 2.6 years, I focus on the 36-month forecast horizon.

[11]The oil well and gas well regressions contain respectively 94,664,756 and 92,442,976 well-month observations [see table 3]

[12]Alternatively, I considered running the experiment with two other price specifications. In the first alternative specification, I used the 36-month NYMEX future contract prices. In the second specification, I used the spot prices at the regional level to account for price heterogeneity across states. Effectively, oil and gas prices can slightly vary across regions, depending on the *quality* of the extracted resource, and the distance it takes to be transported to a refinery site. For example, regions with a resource that is less expensive to refine (e.g. less sulfur content) will receive a better price. Source: `https://www.eia.gov/todayinenergy/detail.php?id=33012`. These two additional specifications did not change the results qualitatively and quantitatively.

[13]The discounted project half-life corresponds to the amount of time required for managers to obtain half of the discounted project's expected cash flow

5 Measurement error

Empirical implementation of any discounted cash flow valuation model involves simplifying assumptions. The most important of these pertains to wells' production and oil and gas price forecast. Precisely, the estimated discount rate can be characterized such that $\tilde{r} = r + \nu$, where $\tilde{r}$ is the estimated firm-year discount rate, r is the true discount rate, and $\nu(\epsilon)$ corresponds to the discount rate measurement error, which is a function of the measurement error in the expected quantities, ϵ. To clearly illustrate the measurement error problem, it is useful to simplify the IRR equation (1)[14], and add some measurement error in the expected baseline quantities (i.e. $\widetilde{BQ}_i = BQ_i + \epsilon_i$) such that:

$$\mu_i = \frac{P_i \cdot \widetilde{BQ}_i}{C_i} - \eta \tag{2}$$

$$\mu_i = \frac{P_i \cdot BQ}{C_i} + \underbrace{\frac{\epsilon_i}{C_i}}_{\text{Estimation Bias}} - \eta \tag{3}$$

In this case, ϵ can be interpreted as the deviation between the manager's true expected quantities and my estimate. If firms systematically had different expectations than the one modeled in this study, the quantities estimates could be biased. However, the nature of this bias will likely be small given that the use of geophysical models such as the one I use is widely established in the oil and gas industry. Equally, if the measurement error of the expected quantities were to be correlated with the variable of interest (i.e. $E[\epsilon|IdiosyncraticRisk] \neq 0$), the estimate would be biased. To alleviate this issue, I am working on introducing an instrumental variable.

However, an additional source of biases arises from my strategy to extract the discount rate. Realistically, managers' expectation over the wells' quantity is likely to be more volatile in the early stage of the field's life cycle than in the more mature stage. Indeed, as more information becomes available the variance of their beliefs should decline. Therefore, the conditional variance of the measurement error[15] of the wells in the high idiosyncratic exposure section of the sample should be greater than for the wells in the low idiosyn-

[14] I assume that the well is infinite-lived and that the depletion rate is constant over time. These additional assumptions enable me to derive a closed-form solution. The full derivation of equation (2) can be found in appendix II.

[15] $Var[\epsilon|IdiosyncraticRisk = 1] \geq Var[\epsilon|IdiosyncraticRisk = 0]$

cratic exposure section. This directly impacts the measurement error of the discount rate $\nu(\epsilon)$. However, it is possible to characterize the direction of the bias and show that it goes in the opposite direction of the result [see Figure 9]. As the variance of the expected quantities measurement error increases, the left tail of expected returns distribution I estimate extends further to the left. Thus, for a fixed confidence interval assumed to capture the firm-year discount rate, I obtain downward-biased estimates. This implies that the estimate of the idiosyncratic risk coefficient will likely provide a lower bound estimate of the relationship between discount rate and idiosyncratic risk.

6 Results

6.1 Do managers price idiosyncratic risk

The main regression of this section investigates the role of idiosyncratic risk on managers' discount rate calculation. The unit of observation is at the firm-idiosyncratic exposure-year level[16]. The basic regression goal is to evaluate if idiosyncratic risk exposure impacts the project discount rate calculation. Table 4 shows that idiosyncratic risk appears to be priced by managers, where column 1 presents the baseline threshold interval for the discount rate approximation, while columns 2-5 replicate the results under different threshold definitions as a robustness exercise.

6.1.1 NPV decision rule and model mispecification

One hypothesis imposed by the revealed preference strategy is that firms base their investment decision on the NPV rule. Although managers overwhelmingly report using the NPV decision rule when making investment decisions (**???**), empirical evidence suggests that firms also consider the option value of their investment when deciding to invest (e.g. (**?**). In a world where managers use a model incorporating the project's option value to determine their investment decision, the optimal investment trigger then includes the project's

[16] $r_{i,j,t}$, where i corresponds to the firm index, j corresponds to whether the observation is from the high or low idiosyncratic area and t corresponds to the year the well was drilled.

idiosyncratic risk[17]. However, there are two key reasons why this distortion does not alter the core results discussed in the next section.

First, the main goal of this study is to investigate how firms' hierarchy structure mediates the effect of project-level idiosyncratic risk on the discount rate calculation. In other words, I decompose the firms' discount rate sensitivity to the project-level idiosyncratic risk to find how much can be attributed to the firms' hierarchical structure. It is unlikely that the firms' decision to use the NPV versus the real option decision rule is related to the firms' hierarchical structure.

Second, I am working on two robustness test specifications to directly rule out the real option problem. In the first specification, I make use of the fact that the real option value of a project depends among other things on the time-to-expiration. For example, the shorter the amount of time firms have to decide when drilling their well, the smaller is the real option value. Thus, as a robustness exercise, I derive the results working exclusively with wells close to the lease expiration, which is when the firms have limited timing flexibility. In the second robustness specification, I plan to directly estimate the discount rate using a real option framework.

6.2 What affects managers' price of idiosyncratic risk?

In this section, I first provide an overview of the existing theoretical and empirical evidence relating managers' career concerns to risk-averse behavior. Then, I introduce the role of firm hierarchical structure and its effect on managers' price of idiosyncratic risk. Finally, I test how field managers' ability to diversify project-level idiosyncratic risk (i.e. the number of wells they can drill) impacts the price of idiosyncratic risk.

Managers are concerned about the ultimate consequences of their decisions on their career outlook, specifically their reputation (**?**). Indeed, managers care both about today's investment outcomes and the impact of their decisions on their future career prospects, their human capital (**?**). However, firms' owners solely care about the financial performance of the firm. The manager's dual objectives create tension and could

[17] see appendix III

ultimately lead to incentive misalignment with the firm's owners. (?) provides empirical evidence that reputation concern negatively impacts managers' preference for risky investment opportunities. This relationship is not limited to the owner-manager relationship, but also applies to the relationship between senior managers and their subordinates (?).

Indeed, a growing body of research suggests that firms are not the monolithic blocks often portrayed in the finance literature. Instead, they are composed of a complex hierarchical structure, in which senior managers oversee the strategic imperative and delegate operational tasks to junior staffs. In the oil and gas industry, such junior employees hold a crucial decision-making role (?). Indeed, knowledge of local geological characteristics and precise technical know-how is crucial to making optimal investment decisions over a large number of small investment decisions[18]. Consequently, most firms design regional business units, each in charge of spending an allocated budget. In support of such a strategy, theoretical work by ? suggests that delegating investment decision making to the agents with the highest amount of information regarding a specific decision improves resource allocation. Empirically, the delegation of authority has been linked to team specialization (e.g. ???), where workers in jobs that require technical skills usually benefit from a greater level of authority. This approach increases the likelihood that people most familiar with the local rock formation specificity will make investment decisions with limited interference[19]. For example, Exxon Mobil Corporation publicly revealed its North American upstream business structure [see figure 10], which is explicitly organized into regional units. Similarly, oil and gas firms' shareholder communication documents provide salient examples of how the geological formations impact firms' hierarchical structure[20].

The decoupling between capital allocation and the investment decisions might lead to misalignment of incentives between senior managers and field managers (?). For example, when senior managers allocate the budget across multiple field managers, the idiosyncratic risk exposure of a given field manager will be

[18]The average firm in this study invested in 44 projects per year and drilled a total of 230 projects between 1983 and 2005.

[19]"Chevron's North America upstream business is headquartered in Houston, Texas, and is organized into regional business units that explore for, develop, and operate oil and gas assets." Source: `https://www.chevron.com/operations/exploration-production/exploration-production-in-north-america`

[20]Generally, basins are constituted of multiple fields [see figure 11], which provide a logical structure for firms to organize the information provided to shareholders. Source: `https://s2.q4cdn.com/462548525/files/doc_financials/quarterly/2018/q2/Q2-2018-DVN-Operations-Report-FINAL.pdf`.

greater than that of the senior manager. Therefore, the loss of diversification arising from the hierarchization potentially increases field managers' concerns about idiosyncratic risk, pricing it more aggressively than the better-diversified senior manager. We see a similar story in the asset pricing literature, in which the loss of diversification due to the delegation process distorts the lower-level managers' risk-return preference from the senior managers (**?**).

Additionally, field managers' private benefits (e.g. career concerns or desire to increase their share of the budget next period) might induce them to account for idiosyncratic risk (**?**). Survey evidence reported in **?** indicates that for 65% of American CFOs, previous performance of business units is a key determinant for next period capital allocation. This dynamic is captured in table 5, where the number of projects a given field manager will drill at period "t' depends on his portfolio's relative success at period "t-1'. More importantly, this relation is decreasing in the field maturity. For example, bad performance in the early stage of the field development will more drastically reduce the number of projects the field manager can develop than a similar performance in a more mature field. The theoretical finding presented in **?** translates nicely into this result. Senior managers' tolerance level for failed drilling attempts increases as more information about the field quality accumulates (i.e. lowering the level of idiosyncratic risk). Thus, the probability of canceling the field development becomes less sensitive to poor performance as more information is available to the senior manager.

Consequently, this suggests that firms in which field managers are on average less diversified (i.e. lower number of projects per fields) are more exposed to the idiosyncratic realization of a single well because field managers have an incentive to take it into account. We should expect that after controlling for the total number of wells drilled by a firm in a given year, field managers with many wells to drill should price idiosyncratic risk less than a similar field manager with a smaller number of wells. Effectively, as field managers become more diversified, they price idiosyncratic risk less aggressively, as illustrated in table 6[21].

[21] The results presented in table 6 are obtained using the baseline confidence interval around the discount rate threshold (i.e. 5th to 15th percentile). As a robustness exercise, I run the same regression around other thresholds (Tables 7, 8, 9) to verify how the results are sensitive to the threshold definition. The results appear to be strongly robust to these specifications.

The results provided in this section highlight how the firm hierarchical structure can mediate managers' price of project-level idiosyncratic risk. Through changes in their allocation of the firm budget, bigger (smaller) share of the budget increase (decrease) the number of wells managers can drill, which in turn decreases (increases) their exposure to project-level idiosyncratic risk.

6.3 Endogeneity

Firms unobserved characteristics could be correlated with the field managers diversification level. To alleviate endogeneity concerns, I introduce an instrumented variable. Conceptually, the instrumental variable is the firms newly discovered diversification potential. precisely, every year, I construct a variable that is equal to the average size of the newly discovered field in the firms region of operation. To obtain the instrumental variable, I first measure a given field size as the surface area covered by the field as of 2018[22]. Second, I compute the average size of the newly operational field in a given year in the region of operation of each firms. For example, if a firm operates in Texas and Oklahoma 1983, the instrument variable would correspond to the average size of the fields discovered in 1984 for those two states.

This variable should not be correlated with the firm uncontrolled characteristics. The fact that field get discovered is not by itself random. Indeed, firms actively explore and develop their surrounding region. However, conditional on a field being discovered, its effective size is random. Indeed, in each states, some field turn out to be large, whereas some others end up being small. Thus, it should satisfy the exclusion restriction.

Alternatively, this variable is strongly correlated with the variable of interest, which is the field managers diversification level (i.e. the average number of wells field managers

[22]Since I study the period 1983-2005, measuring the field size as of 2018 provides me with enough time lag to have a proper measure of the effective field size

7 Discussion

Why would senior managers expose field managers to a high level of idiosyncratic, given that they will price it as shown in this study? If the senior manager behaves in an optimal fashion, she should internalize the field managers' high exposure to idiosyncratic risk and consider it when deciding the number of fields to develop and the budget allocation for each field. To explain these seemingly contradictory states, I propose that there is a trade-off taking place, which I describe below.

We can think of the senior manager optimization decision as a two-steps problem. First, she must choose "N" fields with uncertain underlying quality, and then she must decide how much of her budget to allocate to each of the assigned field managers [see figure 1]. Second, each field manager decides which wells they want to develop considering the budget they have been provided with. All things equal, a larger budget implies a greater diversification effect at the field manager level. Thus, from the senior manager perspective, there are two sources of diversification with different implications. First, because there is risk regarding the underlying quality of each field, it might be interesting to diversify part of her budget across multiple fields to reduce her exposure to field-specific idiosyncratic risk. However, as she increases the number of fields to develop, the number of wells her field managers will be able to drill declines, for a fixed senior managers' budget, decreasing the field managers' diversification. Thus, this strategy illustrates a trade-off between reducing her exposure to field idiosyncratic risk while simultaneously increasing the field managers' exposure to projects' idiosyncratic risk.

8 Conclusion

In this paper, I provide a novel and original approach to extract a firm's project-level discount rate. Using a dataset covering the universe of oil and gas wells drilled in the United States between 1983 and 2005, I first find that managers price idiosyncratic risk contrary to traditional corporate finance theory. The empirical results presented in the paper suggest that firms' hierarchical structure plays an economically and statistically important role in mediating the phenomenon. Effectively, because senior managers split their budget across multiple field managers, this makes the field managers less diversified than the senior manager at the project level. This loss of project-level diversification translates into a more aggressive pricing of idiosyncratic risk by the field managers. Although the results of this paper suggest that well-diversified firms appear to price project-level idiosyncratic risk because of the hierarchical structure, it does not discuss if the phenomenon deviates from optimal behavior. Future research should investigate if the loss of diversification at the field level (i.e. division level in a traditional firm) is value maximizing for the firm because it increases the number of divisions it can run at the same time. The overall consequence of such a trade-off has not yet been investigated in the literature.

9 Appendix

9.1 Appendix I: ARP model adjustment for empirical evaluation

To estimate this nonlinear model, I linearize the equation such that:

$$
\begin{aligned}
q_{t,i} &= A_i(1+b\theta t)^{\frac{-1}{b}} \\
ln(q_{t,i}) &= ln(A_i) - \frac{1}{b} ln(1+b\theta t) \\
ln(q_{t,i}) &= ln(A_i) + Ramp_1 + Ramp_2 + \sum_{k=0}^{K} \beta_k t^k
\end{aligned}
$$

Where the last step is obtained from doing a taylor expansion of the term $ln(1+b\theta t)$. For a fixed "t" sufficiently small, the expansion terms converge to 0, since the product of b and θ is close to zero. In other words, I can approximate the hyperbolic decline curve using an order "K" polynomial. Finally, I include two dummy variables, $Ramp_1$ and $Ramp_2$, respectively equal to 1 for the first and second month of the wells production, to account for the wells production ramp-up patterns [See wells first two months of production of figure 8].

9.2 Appendix II: Simplified model

Under the assumption that the model is infinite lived, and that the depletion rate is constant over time, it is possible to rewrite the model in continuous time such that:

$$
\begin{aligned}
0 =& E_0\left[\int_{t=0}^{\infty} P_t \cdot \widetilde{BQ}_i e^{-(\eta+\mu_i)t}\right] - C_i \\
0 =& \frac{P_i \cdot \widetilde{BQ}_i}{\eta + \mu_i} - C_i \\
\mu_i =& \frac{P_i \cdot \widetilde{BQ}_i}{C_i} - \eta \\
\mu_i =& \frac{P_i \cdot BQ_i}{C_i} + \frac{\epsilon}{C_i} - \eta
\end{aligned}
$$

Where $B\tilde{Q}_i$ is the baseline production level of well "i" with measurement error such that $\widetilde{BQ}_i = \widetilde{BQ}_i + \epsilon$,

η is the constant depletion rate, P_i is the three-year forecast of oil or gas price, C_i is the drilling cost, t is the number of months since the well has been drilled, and μ_i is the project IRR. It is important to note that for this derivation I no longer work with the monthly production of well "i" ($\tilde{Q}_{i,t}$). Instead, the production function is written as a function of the baseline production level. This is possible to rewrite the problem in this fashion because the depletion rate does not depend on the time since the well was drilled.

9.3 Appendix III: IRR versus Real Option

The goal of this section is to illustrate the effect of a manager using a real option decision rule would have on the discount rate estimation.

For example, assume that managers exercise project based on an NPV rule (i.e. invest when $V \geq I$), and my strategy to extract the discount rate relies on an internal rate of return (IRR) rule. For simplicity, assume that wells produce for one period such that, the manager invest at t=0 and get the cash flow (i.e. the oil, V) at t=1. Such a rule implies that managers will invest whenever $\frac{V}{1+r} \geq I$. If we estimate the IRR here, we get: $r_{NPV} = \frac{V}{I} - 1$.

Now, assume that instead of using an NPV rule, managers use a real option decision rule (i.e. invest when $V^* \geq I$ and $V^* \geq V$). If we estimate the IRR here, we get: $r_{RO} = \frac{V^*}{I} - 1$. Comparing both estimated discount rate yield: $r_{RO} \geq r_{NPV}$. Importantly, r_{RO} depends on V^*, which in turn depends on the level of idiosyncratic risk of each project. This happens because real option optimal threshold incorporates the investment cash flow uncertainty. In other words, for projects with greater idiosyncratic uncertainty, r_{RO} will be mechanically greater if firms use a real option decision rule.

Interestingly, as the time-to-expiration of the real option converges to zero (i.e. the firms no longer have timing flexibility) and $r_{RO} = r_{NPV}$.

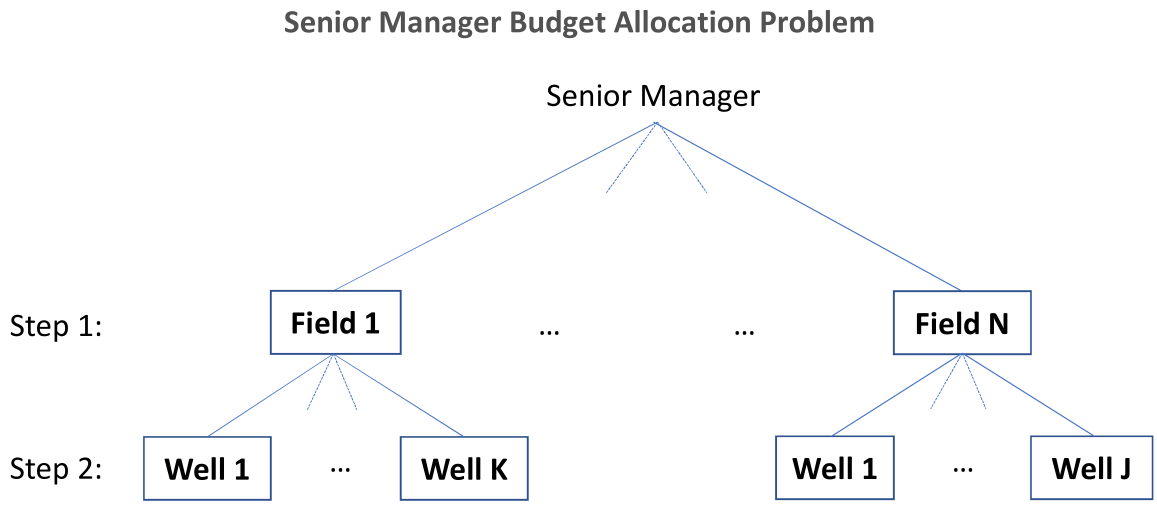


Figure 1: The senior manager allocation problem.
This figure provides a graphical illustration of the senior manager budget allocation problem. In the first step, the senior manager must choose the number of field she wants to develop. Then, in the second step the senior manager must decide how much budget she wants to allocation to each of the field she decided to develop (i.e. this is equivalent to deciding the number of wells she want to have drilled in each field).

Progression of field development over time - Panhandle Oil Field (Texas)

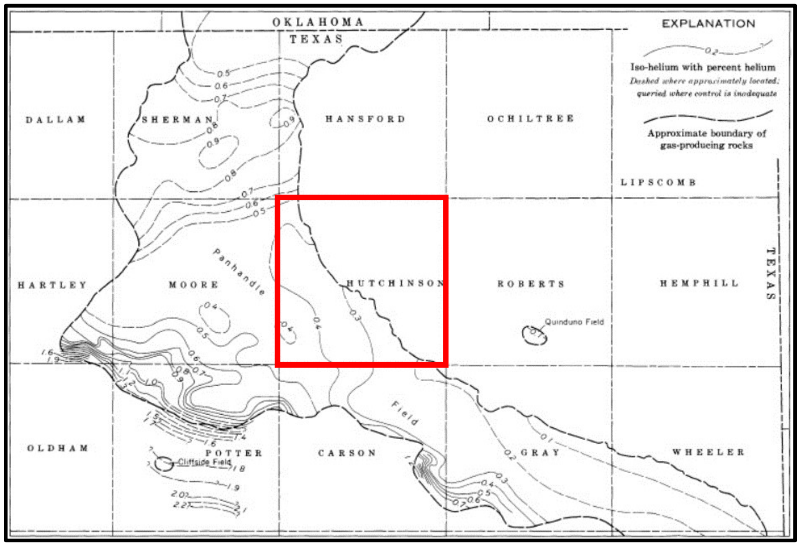


Figure 2.1 - 1961 map of approximate boundary of Panhandle oil and gas field producing region. Source: *Anderson and Hinson, 1961; Boone 1958; and G.B. Shelton, U.S. Bureau of Mines, written communication, 1958* .

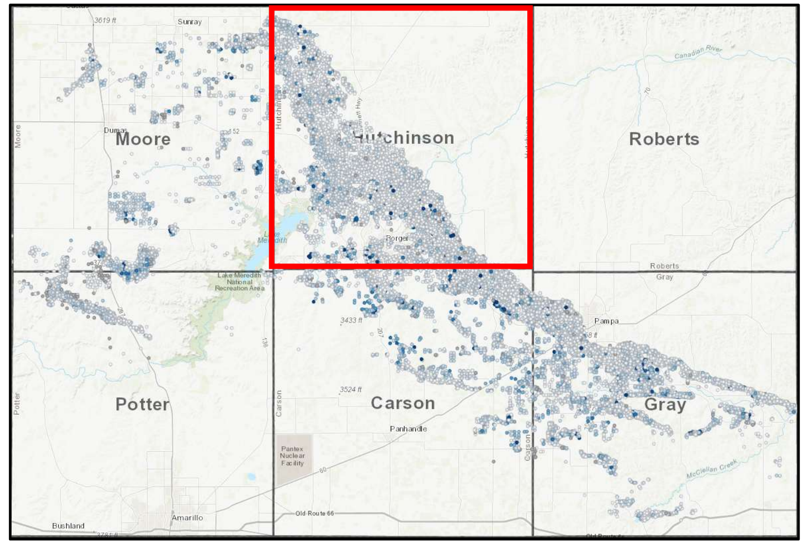


Figure 2.2 - 2010 map of cummulative oil and gas wells drilled in the Panhandle field.

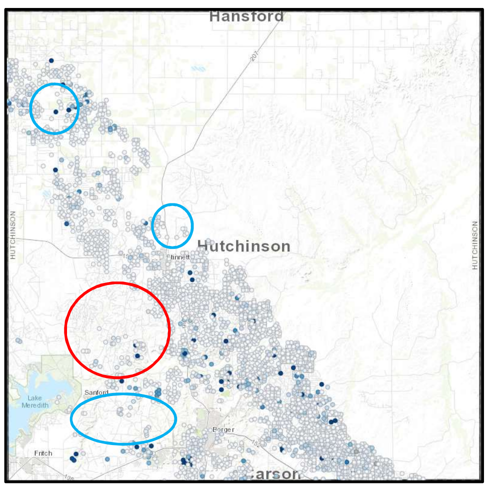


Figure 2.3 - Field development in 1960

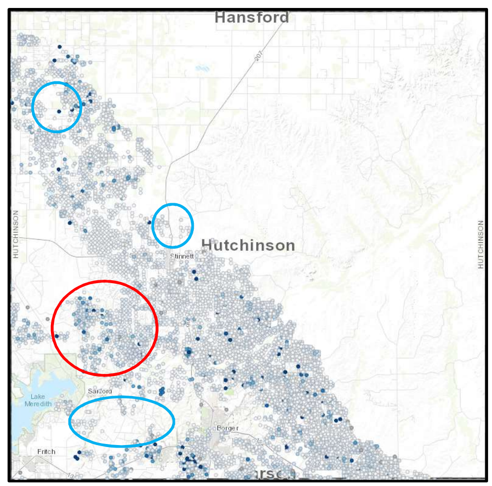


Figure 2.4 - Field development in 1985

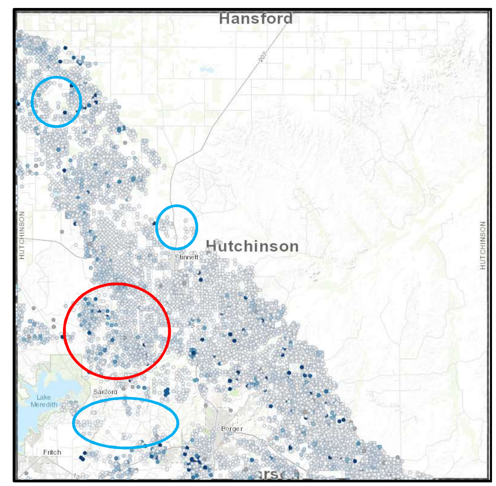


Figure 2.5 - Field development in 2010

Figure 2: Panhandle Field (Texas) Development Progress Over Time

This panel of figure plots the evolution of the Panhandle field development over time. Figure 2.1 provide the initial expectation of the field boundary. Figure2.2 provide an updated view of the field development and figure 2.3 to 2.5 illustrate the evolution of a portion of the field.

Geographic Distribution of the Projects

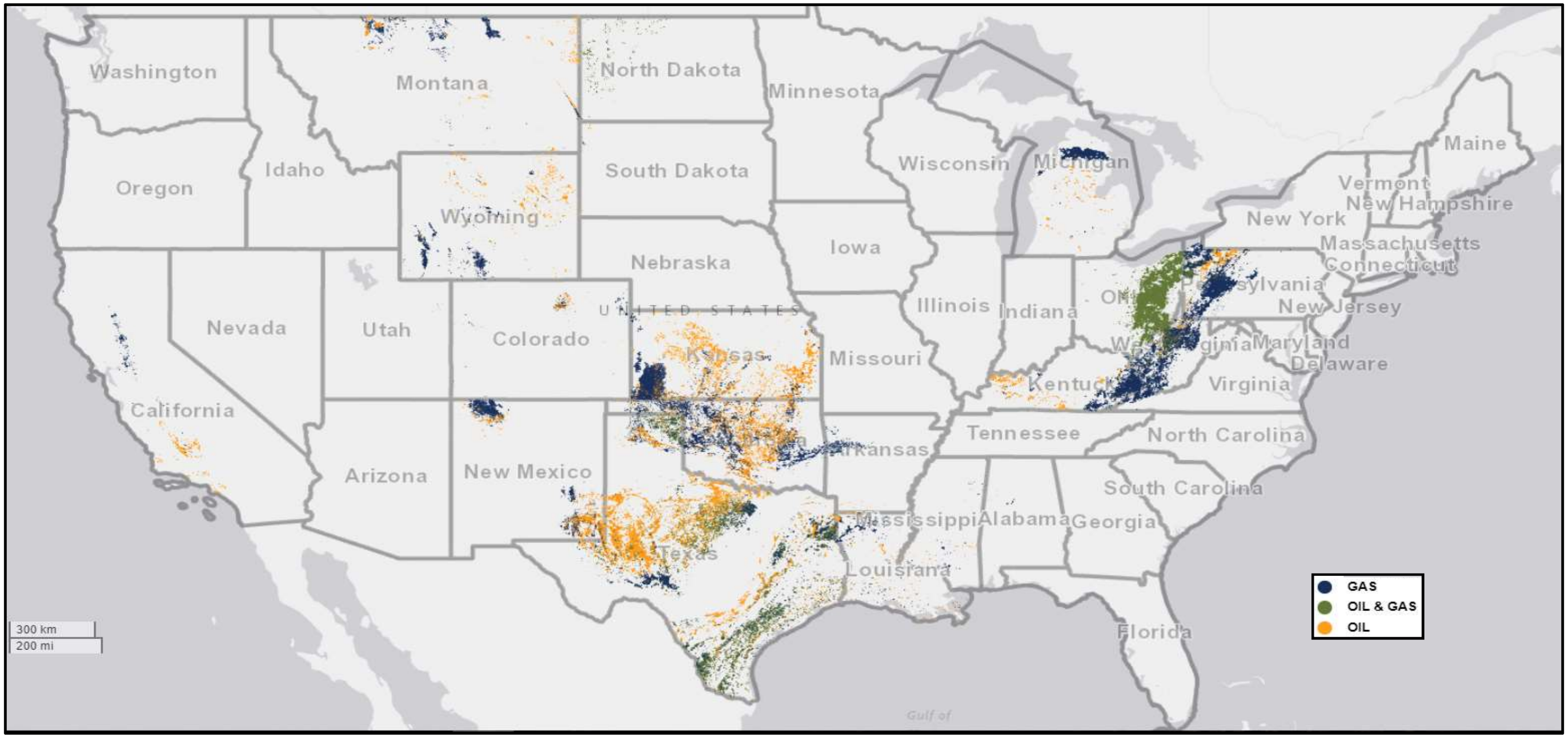


Figure 3: Projects Geographic Distribution

This figure plots the full sample of projects included in the analysis. In total, 651,033 vertical wells were completed for the period ranging from 1983-2005. The map provides information on the regional intensity, and the types of resources extracted at each geographical location.

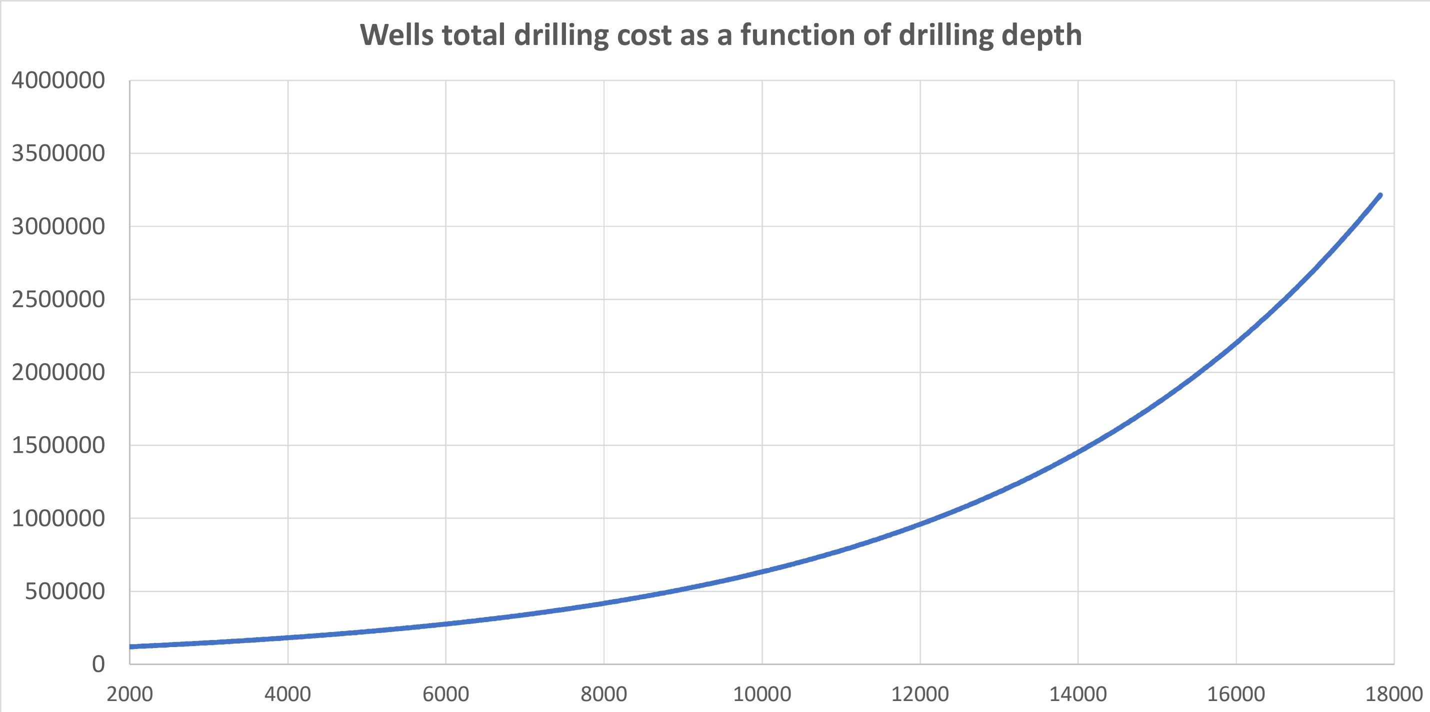


Figure 4: Well Cost as a function of drilling depth

This figure plots the estimated relationship between drilling cost and wells depth for the average well, filtering out year and firm fixed effects. The total drilling cost is on the y-axis and the well's total depth is on the x-axis. Deeper wells are exponentially more expensive, as illustrated by the graph. The R-squared 0.8230, indicating that most of the relation can be explained by the depth of the well.

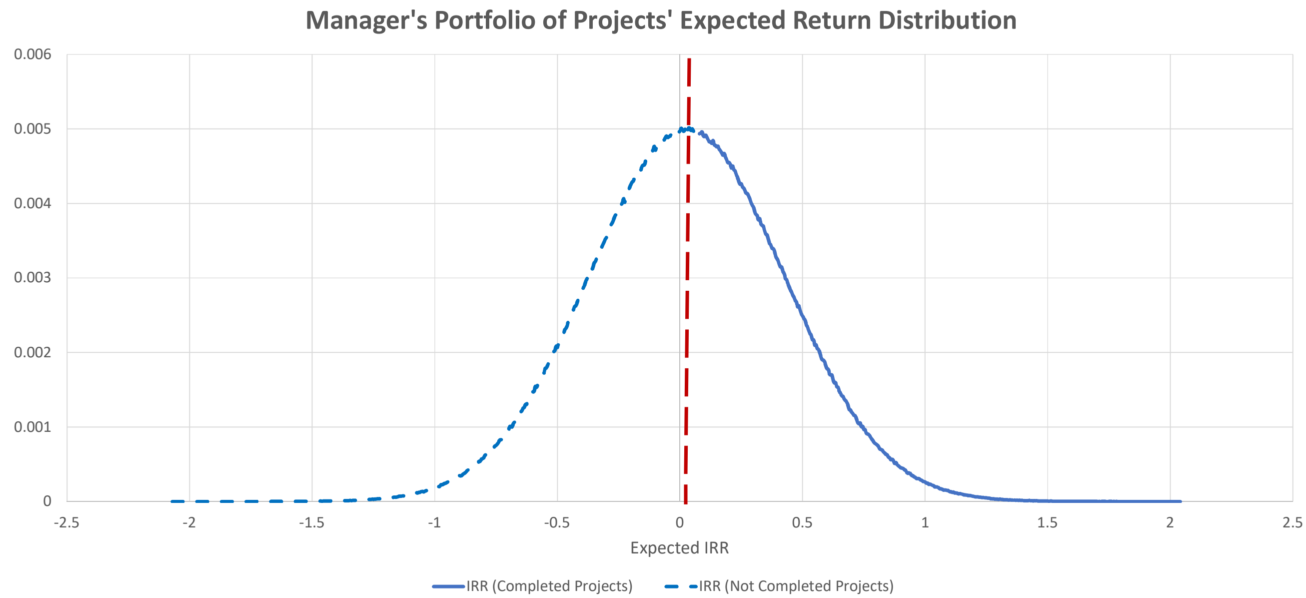


Figure 5.1: Distribution of Projects Expected Returns

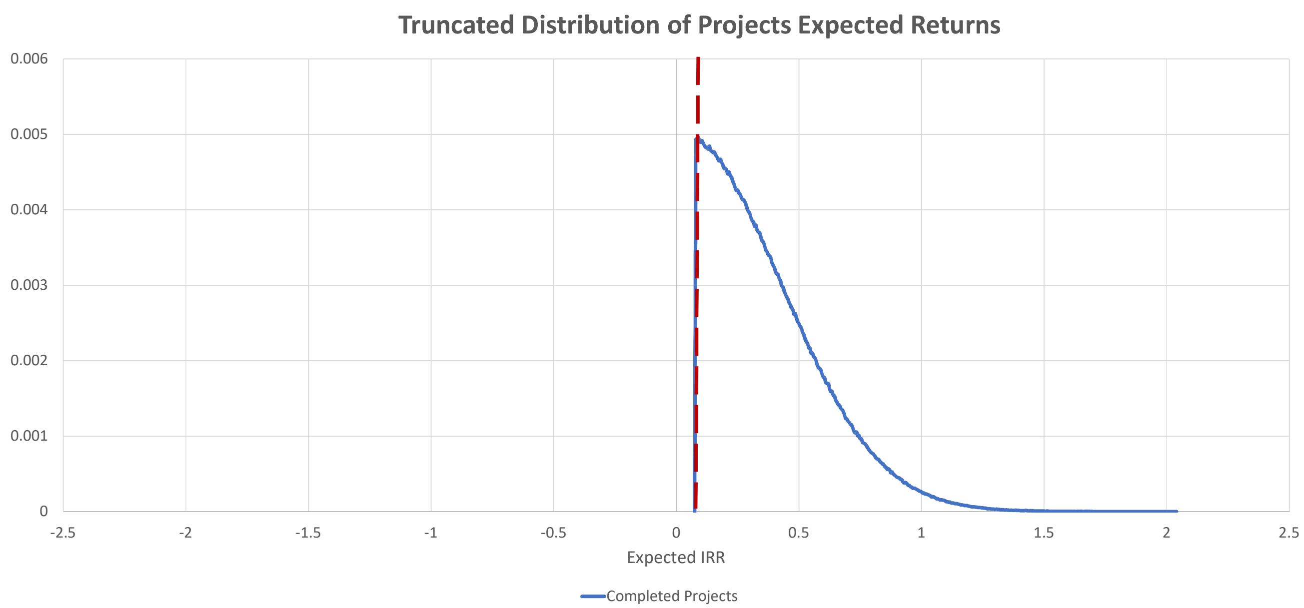


Figure 5.2: Truncated Distribution of Completed Projects

These figures schematize the true distribution of the projects' internal rate of return for a given firm year. In figure 4.1, the red dash line represents the minimum discount rate required for the firm to complete a given project. Figure 4.2 plot the truncated distribution of projects expected returns.

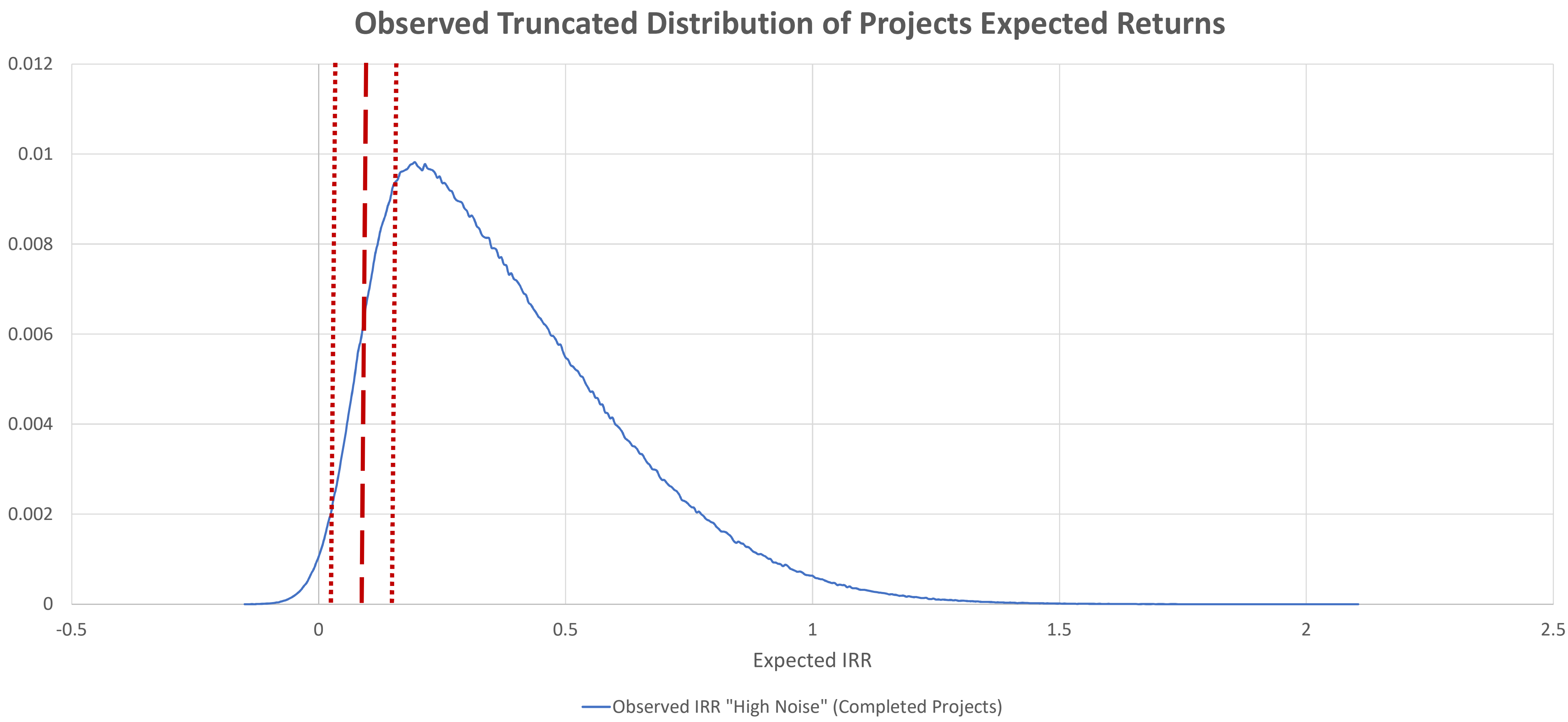


Figure 6: Observed Truncated Distribution of Projects Expected Returns

This figure schematizes the observed distribution of the completed projects' implied internal rate of return for a given firm-year. The red dash line represents the projects minimal rate required for the firm to complete them that was set in figure 4. Now, because of measurement error, it is no longer possible to look at the minimum rate to infer the firm discount rate. The red dotted line represents the interval used to estimate the firm discount rate.

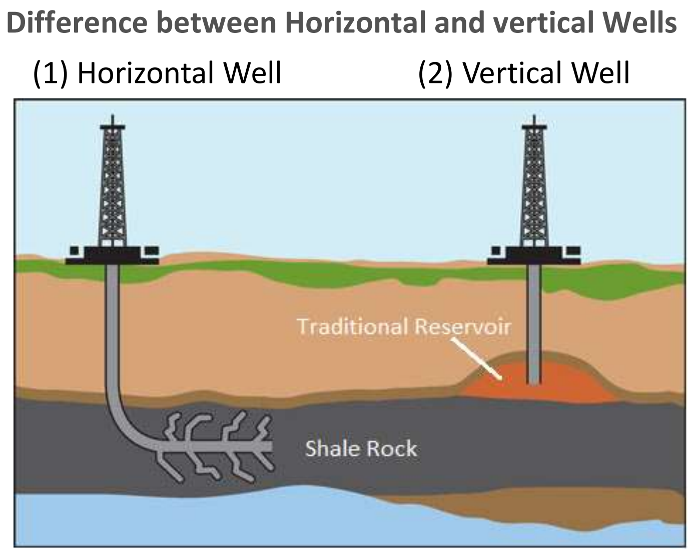
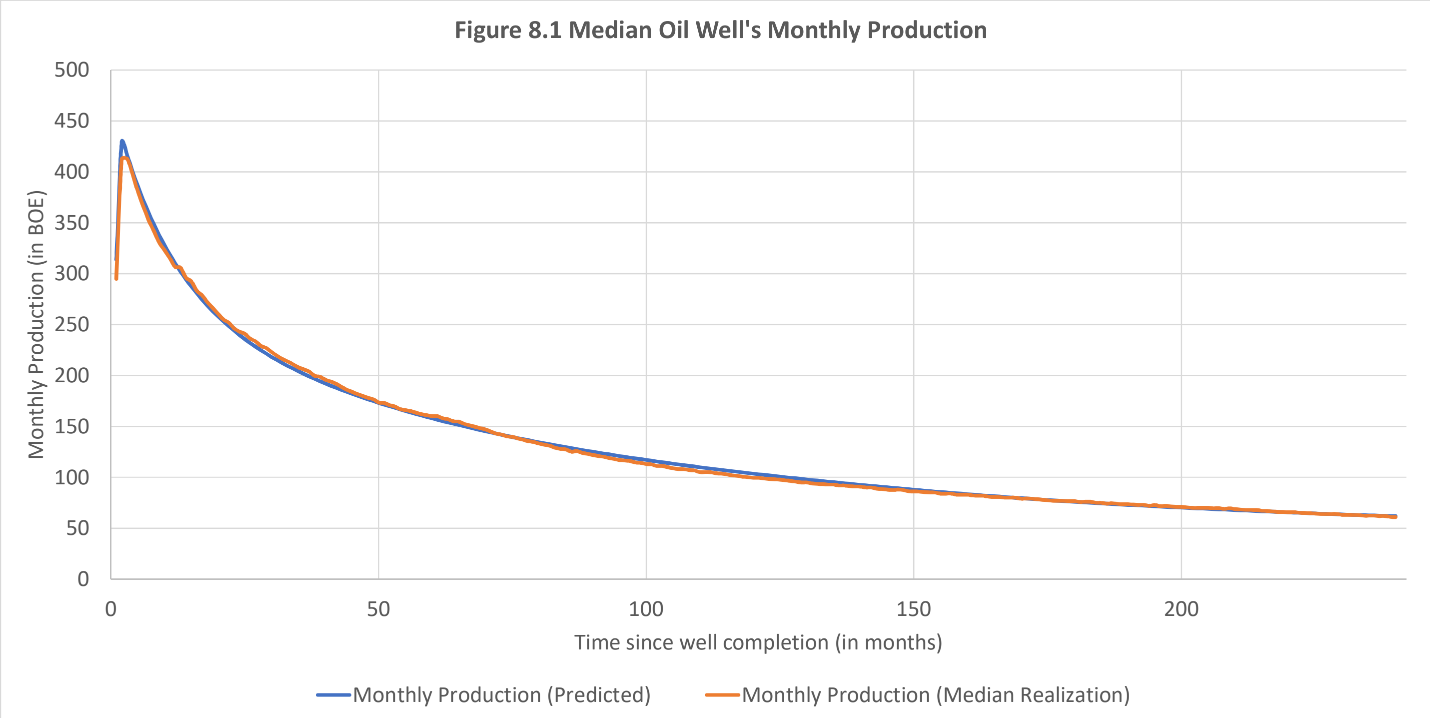


Figure 7: Vertical wells versus Horizontal Wells.

This figure provides a graphical illustration of the difference between horizontal and vertical well. Vertical wells represent the older technology, predominantly used in the first part of the American oil and gas development (i.e. 1900-2005). Vertical wells drilled in those years traditionally targeted oil or gas reservoirs that could roughly be represented by the drawing. In contrast, horizontal wells are generally used in region were vertical wells technology is not economically efficient.



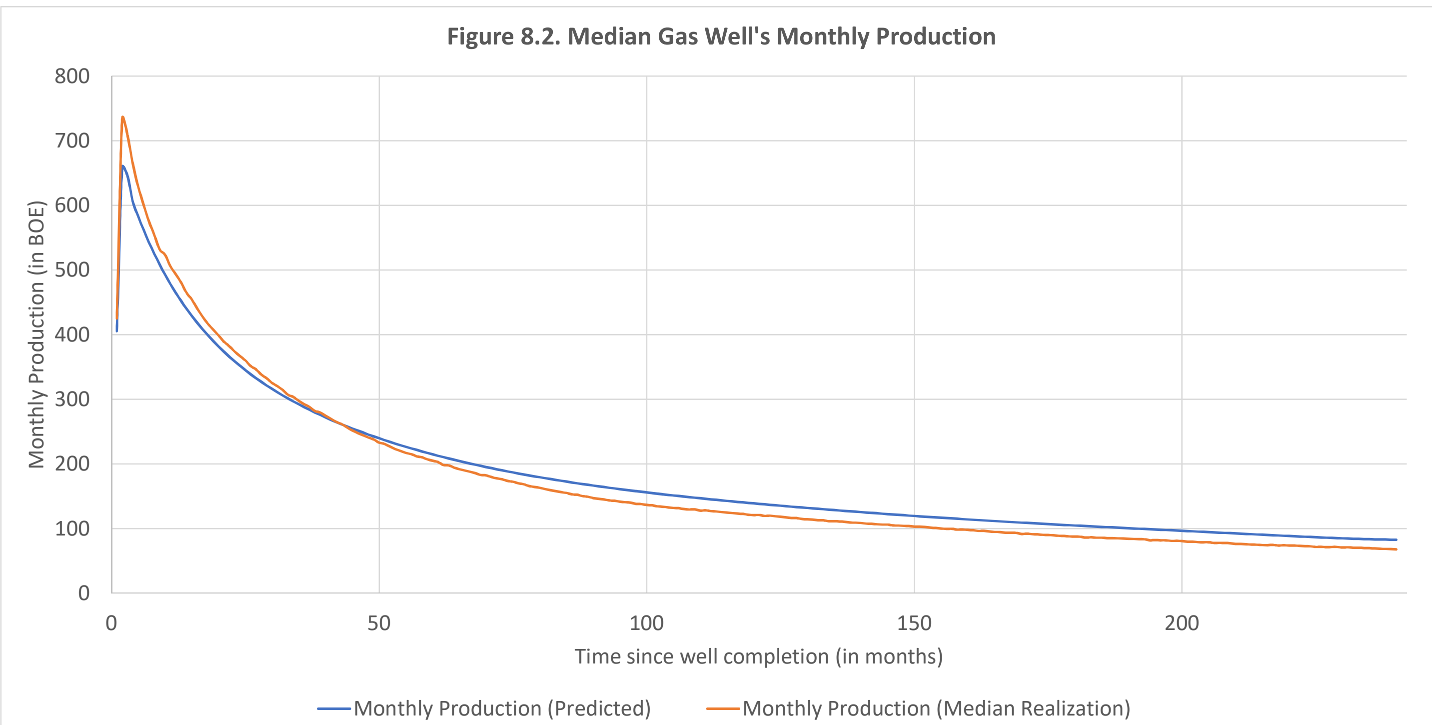


Figure 8. Realized Median Well Output versus Predicted median Well Output

These figure plots both the predicted monthly production and the realized monthly production for the median well in the sample. The monthly production is measured in barrel of oil equivalent (BOE) is represented on the y-axis and the time since well completion (in months) is on the x-axis.

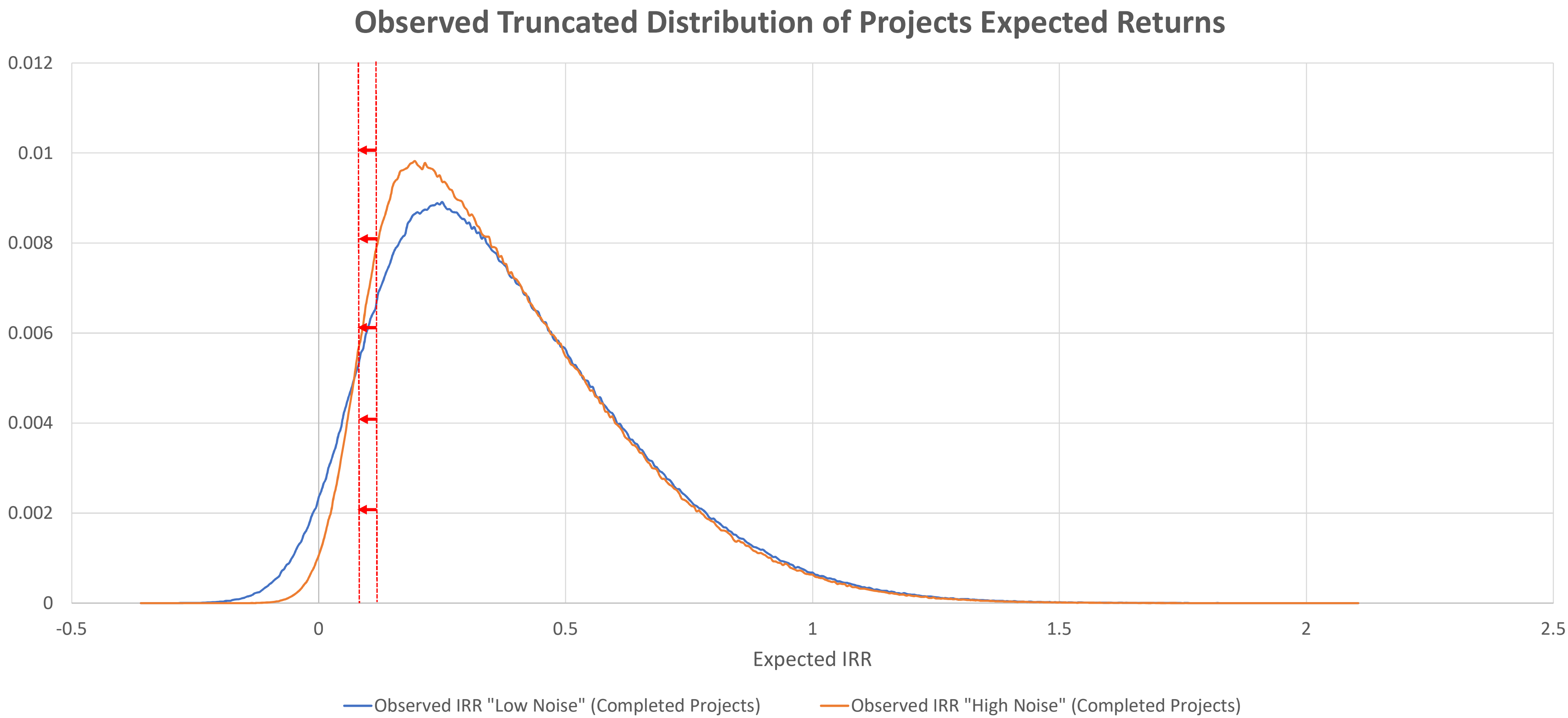


Figure 9: Observed Truncated Distribution of Projects Expected Returns
This figure schematizes the observed distribution of the completed projects' implied internal rate of return for a given firm-year when the expected quantities measurement increases. For illustrative purposes, I assume that the true discount rate defined in figure 4 could be approximate using the 10th percentile of the distribution. Thus, red dotted line illustrates how the downward bias would affect the estimated discount rate for an increase in the measurement error.

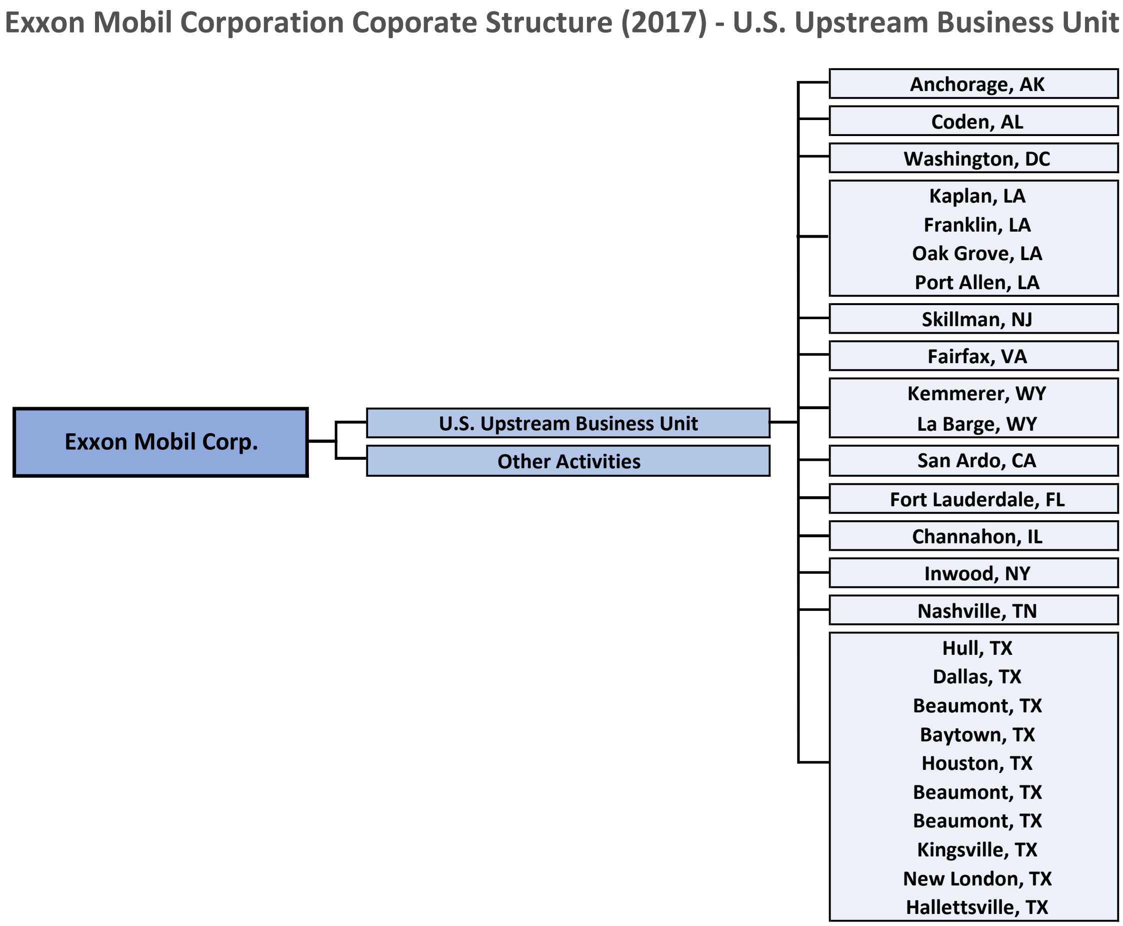


Figure 10: Corporate Structure of Exxon Mobil Corporation (2017).
This figure present a representative example of the corporate tree structure for a firm with upstream activities across multiple regions of the Unites States. As for most firms with upstream activity, the business unit are organized into geographic region. Source: Lexis Nexis Academic Edition.

Oil & Gas Basin and their Respective Fields

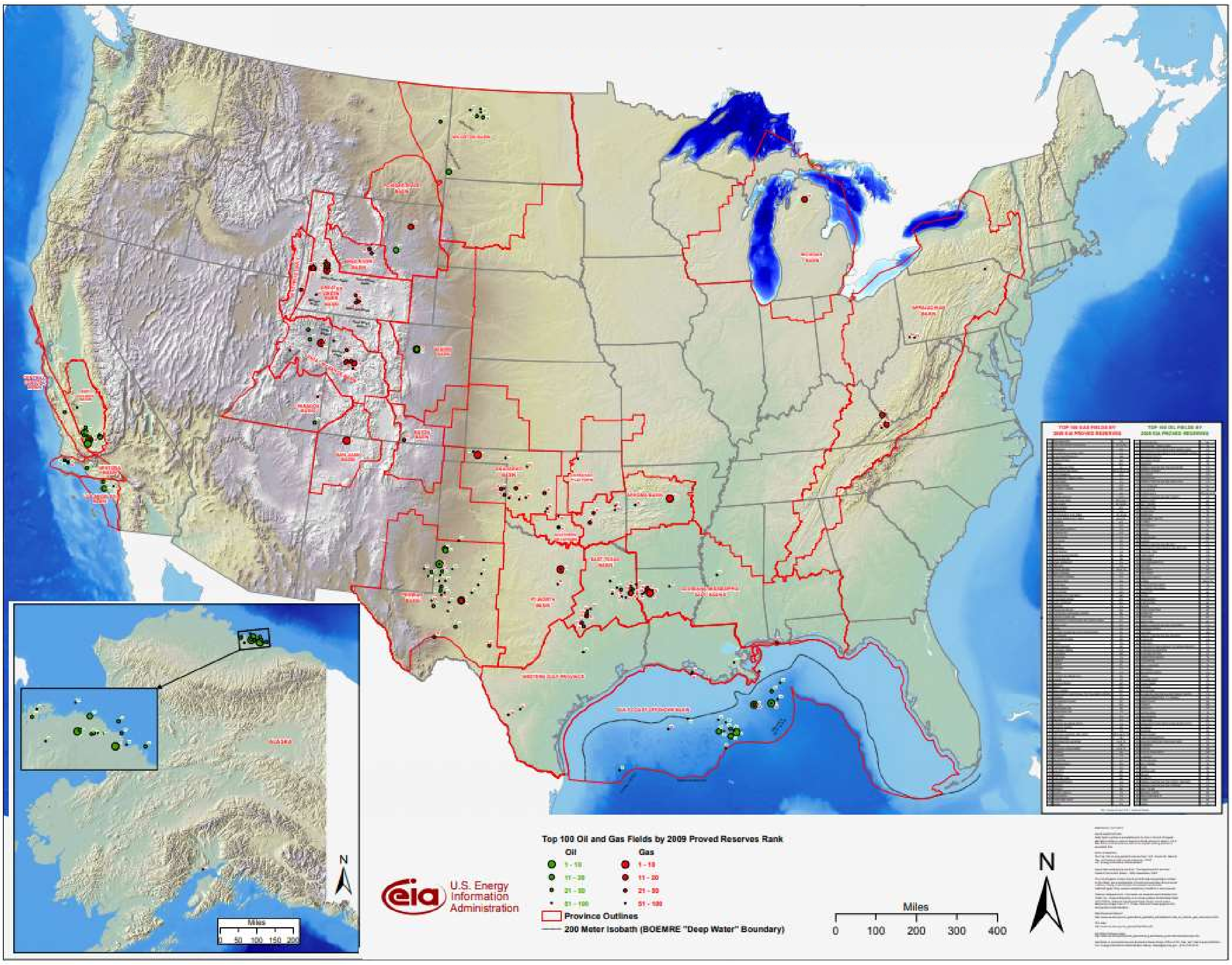


Figure 11: Oil & Gas fields and Basin.

This figure provides a crude illustration of the number of oil and gas fields in a given geological basin. The red line represents the boundary limits of each geological basin, while the green and red dots map the position of oil & gas fields. The figure solely includes the 100 biggest fields ranked by their 2009 proved reserves. Source: https://www.eia.gov/oil_gas/rpd/topfields.pdf

Table 1: Dry Hole Probability during development stage of oil & gas field

This first part of this table reports the marginal probability of drilling a dry hole, estimated using a Probit regression, given the wells' percentile rank quartile. The period of the sample is from 1983 to 2005. The unit of observation is at the well level. In the sample, a well is identified as being a dry hole if it is found to be incapable of producing either oil or gas in sufficient quantity to be commercially profitable. The quartile represents the percentile of the Rank Order of the wells. For example, the wells included in the first quartile were among the first 25% of their respective rock formation to be drilled. The second part of this table present the marginal effect for the probability of a dry hole, for wells drilled in each of the 4 potential quartiles of a field development. Similar estimates, economically and statistically, are obtained when running a logit regression model. T-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Pr(Dry Hole)	Pr(Dry Hole)
	(1)	(2)
(β_1) Percentile Rank Order	-1.1600***	-0.3176***
	[-341.36]	[-43.18]
Year Fixed Effect	No	Yes
Log Likelihood	-2.85e+05	-2.71e+05
N	344,729	344,729

Sample Estimates	Marginal Effect	Z-Stat
First Quartile of Field Life Cycle	0.386***	[1191.77]
Second Quartile of Field Life Cycle	0.282***	[492.39]
Third Quartile of Field Life Cycle	0.193***	[277.13]
Fourth Quartile of Field Life Cycle	0.124***	[178.67]

EIA Estimates	Pr(Dry Hole)
Development stage	15.55%

Source: https://www.eia.gov/dnav/ng/ng_enr_wellfoot_s1_a.htm

Table 2: Summary Statistics for the period 1983-2005

	Mean	Median	Std. Dev.
Wells per Firm	229.5	65.0	909.3
Wells per Firm-Year	43.5	19.0	88.2
Fields per Firm	23.8	10.0	52.2
Wells per Field	465.7	213.0	1377.4
Firms per Field	45.1	27.0	70.3
Cost Data			
Drilling Cost	608,908	340,000	1,058,239
Drilling Cost (per foot)	83.21	54.54	150.11
Royalty Rate	18.17	17.19	3.05
Operational Cost (as a percentage of cash flow)	20%	20%	0%
Well First Year Production			
Oil (in Barrel)	9,805	258	87,675
Gas (in MBTU)	108,109	8,664	508,815
BOE (Barrel of Oil Equivalent)	27,823	3,722	139,522
Nominal Price			
Oil WTI (Per barrel)	42.82	38.03	15.65
Gas (Per mcf)	2.70	2.09	1.53

Table 3: Wells' Production Flow Estimates

This table reports coefficient estimates from an OLS regression. The production variable correspond to the well's production "t" months after the well was completed. The precision of those coefficient is important to properly match the realized production data. For this reason, I allow for 21 digits. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	(1) Gas Well	(1) Oil Well
(β_1) Rank^1	-0.0333509188349963***	-0.0323296057069219***
	[-196.65]	[-208.69]
(β_2) Rank^2	0.00050764761937399***	0.00058594568480729***
	[63.06]	[79.65]
(β_3) Rank^3	-0.0000063800489147***	-0.0000082830415717***
	[-36.86]	[-52.44]
(β_4) Rank^4	0.00000005270655559***	0.00000007234590972***
	[27.43]	[41.33]
(β_5) Rank^5	-0.0000000002575165***	-0.0000000003662680***
	[-22.55]	[-35.30]
(β_6) Rank^6	0.00000000000066687***	0.00000000000098003***
	[19.35]	[31.40]
(β_7) Rank^7	-0.0000000000000007***	-0.0000000000000010***
	[-16.98]	[-28.55]
(β_8) Ramp^1	-0.4285706419697133***	-0.2748617110648319***
	[-224.55]	[-159.18]
(β9) Ramp^2	0.0152751192772810***	-0.0185934528662633***
	[8.38]	[-11.26]
Firm-Year Fixed Effect	Yes	Yes
Year-Region Fixed Effect	Yes	Yes
R-Squared	0.6125	0.6681
N	92442976	94664756

Table 4: Idiosyncratic Risk and Firms Projects' Discount Rate

This table reports coefficient estimates from an OLS regression for the discount rate computed using the multiple interval to capture the firms effect discount rate. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate Threshold			
	5^{th} to 15^{th}	2.5^{th} to 12.5^{th}	2.5^{th} to 7.5^{th}	5th to 10th
	(1)	(2)	(1)	(2)
(β_1) Idiosyncratic Risk	4.1291***	3.7590**	3.6267**	3.7908**
	[3.00]	[2.42]	[2.26]	[2.11]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0111	0.0078	0.0097	0.0110
N	21429	20823	9076	9007

Table 5: Capital Allocation Across Firms Investment Portfolio

This table reports coefficient estimates from an OLS regression. The average Field Projects' Relative Performance variable correspond to a ratio of the wells in a given field average productivity divided by the overall productivity of the firms. The variable Interaction, correspond to the investment increase sensitivity to performance as the field becomes more mature. For example, a coefficient of -0.022 suggest that investment increase is less sensitive to well performance as the fields become more mature. The errors are cluster at the firm level. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Next Period Field Manager Budget Increase		
	(1)	(2)	(3)
(β_1) Average Field Projects' Relative Performance	3.027***	3.130**	3.282***
	[3.37]	[2.57]	[2.74]
(β_2) Percentile Rank in Formation	0.001	0.001	-0.010***
	[0.64]	[0.21]	[-3.52]
(β_3) Interaction	-0.022**	-0.025*	-0.021*
	[-1.98]	[-1.92]	[-1.67]
Firm Fixed Effect	Yes	Yes	Yes
Field Fixed Effect	No	Yes	Yes
Year Fixed Effect	No	No	Yes
R-Squared	0.0165	0.0256	0.0325
N	53824	53824	53824

Table 6: Firm Hierarchy and Price of Idiosyncratic Risk (5th to 15th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	4.1291***	4.9201***	6.5318***	6.2096***
	[3.00]	[3.47]	[4.26]	[3.64]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.0894**	-0.0927**	-0.1042***
		[-2.79]	[-2.70]	[-2.98]
(β_4) Idiosyncractic Risk * Number of Fields			-0.0297	-0.0581**
			[-1.23]	[-2.19]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0008	
			[-0.76]	
(β_6) Idiosyncractic Risk * Firm Size				0.0007
				[0.80]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0111	0.0121	0.0137	0.0146
N	21429	21429	21429	21429

Table 7: Firm Hierarchy and Price of Idiosyncratic Risk (2.5th to 12.5th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	3.7590**	4.6108***	5.2607***	4.9888**
	[2.42]	[2.92]	[2.91]	[2.35]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.0929**	-0.0801**	-0.1017**
		[-2.58]	[-2.36]	[-2.66]
(β_4) Idiosyncractic Risk * Number of Fields			-0.0050	-0.0433***
			[-0.32]	[-3.99]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0016*	
			[-1.96]	
(β_6) Idiosyncractic Risk * Firm Size				0.0008
				[1.06]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0078	0.0088	0.0094	0.0104
N	20823	20823	20823	20823

Table 8: Firm Hierarchy and Price of Idiosyncratic Risk (2.5th to 7.5th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	3.6267**	4.7065***	5.5503***	5.6319**
	[2.26]	[2.88]	[3.22]	[2.20]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.1133**	-0.0992***	-0.1232***
		[-2.78]	[-2.92]	[-2.91]
(β_4) Idiosyncractic Risk * Number of Fields			-0.0074**	-0.0336***
			[-2.69]	[-5.30]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0015**	
			[-2.32]	
(β_6) Idiosyncractic Risk * Firm Size				0.0003
				[0.50]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0097	0.0116	0.0126	0.0127
N	9076	9076	9076	9076

Table 9: Firm Hierarchy and Price of Idiosyncratic Risk (5th to 10th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	3.7908**	4.7738**	6.9504***	6.9617***
	[2.11]	[2.68]	[5.54]	[3.28]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.1079**	-0.1160***	-0.1270**
		[-2.50]	[-2.85]	[-2.75]
(β_4) Idiosyncractic Risk * Number of Fields			-0.0377*	-0.0541**
			[-1.72]	[-2.80]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0008	
			[-0.59]	
(β_6) Idiosyncractic Risk * Firm Size				0.0002
				[0.31]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0110	0.0127	0.0154	0.0155
N	9007	9007	9007	9007

Table 10: Firm Hierarchy and Price of Idiosyncratic Risk (7.5th to 12.5th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	3.7354**	4.5057**	4.8652*	4.5362*
	[2.26]	[2.65]	[2.02]	[1.84]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.0854**	-0.0706*	-0.0926**
		[-2.31]	[-1.77]	[-2.27]
(β_4) Idiosyncractic Risk * Number of Fields			0.0021	-0.0453*
			[0.07]	[-1.85]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0018	
			[-1.55]	
(β_6) Idiosyncractic Risk * Firm Size				0.0010
				[1.13]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0111	0.0124	0.0131	0.0152
N	9784	9784	9784	9784

Table 11: Firm Hierarchy and Price of Idiosyncratic Risk (10th to 15th)

This table reports coefficient estimates from an OLS regression for the discount rate computed using the interval between the 5th and 15th percentile of the return distribution. The idiosyncratic variable is a dummy variable equal to 1 for the wells were drilled in the first half of a field development, and 0 otherwise. The variable Field Managers Diversification counts the average number of projects each field managers can development in his own field in a given year. The variable Firm size count the total number of projects a firm decided to perform in a given year. The variable Number of Fields count the number of field a firm is active in, in a given year. The variable Firm Size counts the cumulative number of projects a firm drilled from the beginning of its operation up to a given year. For example, if a firm drills one project per year, Firm Size would take the value 1, 2, 3 for the first, second and third year of operation, respectively. Standard errors are cluster and the firm and year level. Terms in bracket correspond to the coefficient T-statistic, * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate	Discount Rate	Discount Rate	Discount Rate
	(1)	(1)	(2)	(3)
(β_1) Idiosyncratic Risk	4.2652***	4.9292***	6.2705***	5.7550***
	[3.54]	[3.84]	[2.96]	[3.07]
(β_2) Idiosyncractic Risk * Field Managers Diversification		-0.0754**	-0.0778**	-0.0879***
		[-2.57]	[-2.20]	[-2.90]
(β_4) Idiosyncractic Risk * Number of Fields			-0.0247	-0.0571
			[-0.61]	[-1.54]
(β_5) Idiosyncractic Risk * Firm Yearly Budget			-0.0007	
			[-0.41]	
(β_6) Idiosyncractic Risk * Firm Size				0.0008
				[0.91]
Firm-Year Fixed Effect	Yes	Yes	Yes	Yes
Within R-Squared	0.0200	0.0212	0.0230	0.0257
N	9667	9667	9667	9667