Capital Budgeting and Risk Management

Paul H. Décaire *

ABSTRACT

Do managers adjust their discount rate to account for projects idiosyncratic risk? To examine this question, I exploit a revealed-preference strategy to extract firms' discount rate. First, using exogenous variation in the level of idiosyncratic risk, I show that on average, firms inflate their discount rate by 7.90% to account for a one-standard-deviation increase in projects idiosyncratic risk. Second, I show that, on average, pricing idiosyncratic risk has a sizable negative impact on firms performance. Finally, I document two empirical channels clarifying how and why the discount rate adjustment for idiosyncratic risk is consistent with a risk management explanation. I first find that firms adjust their discount rate as a risk management tool when facing high cost of external funding. Also, I show that for less diversified managers, greater exposure to project-specific outcomes can affect the price of idiosyncratic risk.

JEL classification: G30, G31, G32.
Keywords: Empirical Corporate Finance, Corporate Investment, Capital Budgeting, Risk Management

*Department of Finance, The Wharton School, University of Pennsylvania, Steinberg-Dietrich Hall office 2425, 3620 Locust Walk, Philadelphia, PA 19104. Email: pdecaire@wharton.upenn.edu. I thank Erik P.Gilje, Michael R. Roberts and Lucian A. Taylor, my dissertation committee, for their continual support and guidance. I also thanks Jules Van Binsbergen, Sylvain Catherine, Vincent Glode, and Jérôme P. Taillard for helpful comments and discussions. I am also grateful for the financial support from the Kleinman Center for Energy Policy, The Mack Institute for Innovation Management, and the Social Sciences and Humanities Research Council of Canada.

One of the most important financial decision problem managers face is to select the best projects among competing investment proposals. To evaluate projects, classical corporate finance theory prescribes that firms discount rate accounts for the systematic risk of a firm's investment opportunities, dismissing the idiosyncratic risk altogether (Bogue and Roll, 1974; Myers and Turnbull, 1977; Constantinides, 1978). Similarly, many academic textbooks warn future managers about the temptation of incorporating a fudge factor in the calculation of the discount rate to account for idiosyncratic risk (e.g., Brealey and Myers (1996)), because of the potentially significant capital allocation distortion. Despite these warnings, survey results of the Association for Financial Professionals (AFP) showed that nearly half of their respondents admitted to manually adjusting their discount rate to account for a project's specific risk[1]. Indeed, when asked managers reported using discount rates that are systematically and substantially greater than their cost of capital (Poterba and Summer, 1995; Graham and Harvey, 2001; Graham et al., 2015; Jagannathan et al., 2016). 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. Yet, despite the focus given to topics pertaining to the discount rate calculation in managers training and its key role in firms internal capital allocation, the empirical literature investigating managers' behavior on the subject remains scarce. In this light, providing empirical evidence on how idiosyncratic risk affects managers discount rate calculation is a first-order problem. To the best of my knowledge, this study is the first to provide direct empirical evidence on how managers adjust their projects discount rate for idiosyncratic risk, and the potential forces affecting this adjustment.

This papers goals are to (i) provide causal evidence that managers account for idiosyncratic risk exposure in the calculation of their discount rate, (ii) document the consequences of idiosyncratic risk pricing on firms performance, and (iii) shed light on the financial mechanisms inducing this phenomenon.

Properly characterizing firms' project-specific discount rate and the quantity of idiosyncratic risk for individual projects is empirically challenging. First, firms do not report this information. Second, it is not usually possible to observe specific firms' individual investment decisions. Third, it is generally difficult to clearly compare the investment 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, it is rarely possible to obtain precise estimates of individual projects expected cash flow.

I overcome these challenges by using a comprehensive and detailed dataset containing the universe of onshore vertical gas wells[2] drilled in the United States from 1983 to 2010, representing roughly $53.41 billion in capital expenditure. Specifically, the institutional setting enables me to

[1] See Jacobs and Shivdasani (2012).

[2] Throughout this paper, a *project* refers to the drilling of a new gas well.

observe individual 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. Effectively, each project in the sample is engineered with an identical drilling technology for which the production function of the projects is transparent, allowing me to compute the projects' expected monthly production. Additionally, every project in the sample produces to the same natural resource –natural gas– simplifying cross-project comparisons. Finally, I capitalize on the rich level of detail in my dataset and the vast literature on project-level production forecasting techniques in the oil and gas industry to obtain plausible expected cash flow for each analyzed project.

In the first part of the paper, I provide causal evidence suggesting that, on average, firms inflate their discount rate by 7.90% to account for a one-standard-deviation increase in projects idiosyncratic risk, contrary to the recommendation of traditional corporate finance theory. Empirically testing for this phenomenon requires a measure of (i) projects idiosyncratic risk, and (ii) an estimate of the firms project-specific discount rate. First, I introduce a novel measure of projects idiosyncratic risk based on the geographic cross-sectional dispersion of projects idiosyncratic profitability shocks. Specifically, for each project I construct a measure of idiosyncratic profitability shock, and then I estimate the dispersion of that measure at the township-year[3] level. Second, using a revealed preference strategy I estimate the firms yearly discount rate from their investment portfolio. To obtain an estimate of firms' discount rate, I proceed in three steps. In the first step, I individually estimate the expected internal rate of return of projects undertaken by the firms. In the second step, I sort the projects into two portfolios for every firm-year subsample, based on their level of exposure to idiosyncratic risk. Practically, for each firm-year I construct two portfolios containing the projects for which the level of idiosyncratic risk is high (low) depending on the fact that the projects' measure of idiosyncratic risk is above (below) the firm-year idiosyncratic risk median. Finally, I estimate the firm's discount rate from the projects undertaken that year with the lowest expected return for each portfolio respectively[4]. The logic is that the firm's discount rate must be at least this low, otherwise these projects would not have been undertaken. Finally, I test the validity of both measures by performing multiple sanity checks.

To mitigate endogeneity concerns, my main strategy relies on a set of fixed effects. The nature of my experiment design allows me of control for factors varying at the firm-year frequency. However, since I measure the managers price of idiosyncratic risk by looking at the discount rate estimate between two portfolios constructed at the firm-year level, a remaining concern as to do with a within-firm omitted variable bias. Precisely, unobservable within-firms characteristics, such as managers experience, could be correlated with my measure of idiosyncratic risk. For example, experienced managers could get assigned to riskier fields, effectively sorting managers on their type

[3]Townships are defines as a 6 miles by 6 miles square of land by the American Public Land Survey System.
[4]Appendix A.1. provide the detailed calculation of those variables.

between the two firm-year portfolios. To obtain exogenous variation on the managers assignment to regions with different risk level, I instrument the projects idiosyncratic risk with the firms peers largest idiosyncratic profitability shocks. Those shocks are obtained after controlling for multiple factors, including township-year (i.e., geographic) fixed effect. Thus, these shocks are controlled for unobservable characteristics that are correlated with their region. Also, after conditioning on my set of controls, the attributes of managers from peers firms should not be correlated with the characteristics of the firms own managers. Finally, since the measure of idiosyncratic risk corresponds to the dispersion of the idiosyncratic profitability shocks, it is reasonable to assume that larger idiosyncratic profitability shocks will have a positive relationship with the idiosyncratic risk variable, all things equal.

In the second part of the paper, I investigate the consequences of idiosyncratic risk pricing on firms performance. I introduce a measure of idiosyncratic risk pricing at the firm-year level to directly test its effect on key firms performance metrics. I find that for the average firm, a one standard-deviation increase in the price of idiosyncratic risk has sizable negative consequences on firms gross profit margin (-5.05%), gross profitability (-0.51%), investment rate (-0.75%) and year-over-year asset growth (-0.81%). These results shed light on the consequences of digressing from the classical corporate finance recommendation and adjusting the discount rate for the presence of idiosyncratic risk.

In the final part of the paper, I investigate why managers account for idiosyncratic risk in their discount rates. Various theories support the potential existence for external channels (frictions between the firms and the financial market) and internal channels (frictions between managers and their superiors). For the external frictions theory, Froot et al. (1993) predicts that in a world with costly external financing, managers would optimally adjust their discount rate to account for risks that cannot be offloaded in the financial market. They recommend that if firms cannot fully diversify their exposure to idiosyncratic risk at the firm level, then they should adjust their discount to account for that source of risk. To empirically test this hypothesis, I build on the empirical development presented in Hennessy and Whited (2007), and I construct five proxies of costly external financing to test its effect on the price of idiosyncratic risk. The empirical results of this section are mixed. Hennessy and Whited (2007) favored proxy of costly external financing produces results that are economically consistent and statistically significant with the prediction of Froot et al. (1993). For the average firm, a one-standard-deviation increase in the cost of external financing results in an increase of the price of idiosyncratic risk between 2.42% and 3.15%. However, although most of the other proxies are consistent with the theoretical prediction, they are not statistically significant. For the internal frictions channel, I analyze the effect of managers' diversification. Since firms allocate their budget across multiple managers, each in charge of a smaller fraction of the total budget. This delegation process results in a loss of diversification at the manager level, since managers' exposure to the specific projects is greater, all things equal.

To obtain a prediction for the effect of managers budget size, I build on the insight developed in Diamond (1984). For risk-averse managers, a larger budget has two effects: (i) it reduces the total quantity of idiosyncratic risk they face, and (ii) it decreases the managers idiosyncratic risk premium[5]. In line with Diamond, I find that managers budget size diversification has a meaningful impact on the firms price of idiosyncratic risk. A one standard deviation increases in firms average managers budget results in a reduction in the price of idiosyncratic risk between -1.13% and -0.62%.

Although there is an important theoretical and surveyed-based literature on firms capital budgeting practices and firms project evaluation processes, this is the first study to provide a data-driven analysis of the phenomenon. Therefore, this represents one of the first attempts to (i) empirically estimate and characterize the role and effect of idiosyncratic risk on the discount rate calculation, (ii) quantify the effects of suboptimal adjustment to the discount rate on firms performance, and (iii) identify the mechanism driving the phenomenon. Below, I review each in greater detail.

First, by estimating that the firms price idiosyncratic risk, this study provides one of the first empirical contributions to the capital budgeting topics discussed in the survey-based literature (Poterba and Summer, 1995; Graham and Harvey, 2001; Graham et al., 2015; Jagannathan et al., 2016). Those papers document and discuss the existence of a puzzling gap between firms estimated weighted cost of capital (WACC) and the discount rate reported in their surveys but do not characterize the magnitude, the consequences, and the mechanisms of how idiosyncratic risk affects to the discount rate. I contribute to this literature by providing a causal interpretation of the role of idiosyncratic risk on the firm discount rate and by providing a direct measurement of its magnitude. This study also contributes to the well-established theoretical literature providing guidance on how managers should effectively compute their discount rate (Bogue and Roll, 1974; Myers and Turnbull, 1977; Constantinides, 1978) among others. This paper establishes that contrary to the classical recommendation for the discount rate calculation, managers appear to include a projects' idiosyncratic risk premium in the calculation of their discount rate.

Second, this paper contributes to the micro-level empirical literature by investigating how managers adjust their discount rate to account for different types of risk. Closely related to this paper, Kruger et al. (2015) 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. While Krugers paper focuses on the role of systematic risk exposure on firms' internal resource allocation, I focus on how idiosyncratic risk distorts the discount rate calculation. Similarly, to the results of Kruger et al. (2015), I find that improperly

[5]Diamond (1984) highlights that a sufficient condition to obtain this phenomenon is to assume that managers have decreasing absolute risk aversion (i.e., DARA) utility function.

adjusting firms discount rate has sizable adverse effect on firms performance.

Third, a vast literature has analysed the effect of costly external financing frictions on firms policies. Miller and Orr (1966) provides a theoretical argument for the role of cash when firms face costly external financing. Bolton et al. (2011) analysis the effect of the cost of external funding on firms investment and financing policies. Fazzari and Petersen (1993) provide empirical evidence on the importance of firms working capital in mediating costly external funding friction. Lyandres (2007) empirically investigates how costly external financing affects the timing of firms investment decision. More directly related to this paper, Froot et al. (1993) studies the relationship between capital budgeting and risk management in the context of costly external financing, at a theoretical level. The authors predict that firms facing costly external financing would adjust their discount rate to account for risks that cannot be hedge or diversified away. I contribute to this literature by providing direct empirical evidence suggesting firms utilize capital budgeting strategies as a risk management tool, in support of (Froot et al., 1993) argument.

In addition, multiple streams of finance literature have investigated how firms characteristics and corporate policies affect managers risk preference. First, to mitigate risk preference misalignment between managers and their superiors, the role of compensation contract has received a substantial amount of attention (Ross, 1973; Holmstrom and Weiss, 1985) among others. To increase managers incentive to pursue riskier projects, market-based contracts have been suggested as a solution (Lambert, 1986). Effectively, a rich empirical literature indicates that market-based compensation contracts affect managers risk preference (Agrawal and Mandelker, 1987; Tufano, 1996; Guay, 1999; Rajgopal and Shevlin, 2002; Coles et al., 2006; Armstrong and Vashishtha, 2012; Gormley et al., 2013) among others. However, theoretical works suggest that market-based compensation contracts can shift managers focus from long-term value maximization to pursue short term benefits (Narayanan, 1985; Bolton et al., 2006). Equivalently, empirical evidence suggests that market-based compensation can induce managers to take on excessive risk (Bebchuk and Spamann, 2010; Dong et al., 2010; Hagendorff and Vallascas, 2011). These results indicate that owners solely using wage contract to align their managers risk preference are exposed to potential negative drawbacks. Second, the finance literature acknowledges the role of firm capital structure in affecting managers risk preference. For example, Jensen and Meckling (1976) and Leland (1998) suggest that as firms leverage increases, managers appetite for risk increases, while Gilje (2016) finds that leverage is negatively related risk appetite when firms are in distress. More closely related to this study, Holmstrom and Costa (1986) provide a theoretical argument suggesting that capital budgeting policies can be used as a complement to compensation contracts to better align managers risk preference. I contribute to this literature by empirically identifying the role of managers budget size as a tool to alter managers risk preference. Precisely, I find that firms superiors can increase the risk tolerance of managers by increasing the size of their allocated budget, suggesting a diversification effect as discussed in Diamond (1984).

The paper proceeds in the following order. Section 1 offers background information on the natural gas industry. Section 2 outlines the data that is used. Section 3 discusses the methodology used to obtain firms' expectation. Section 4 presents the revealed-preference strategy to estimate the discount rate. Section 5 introduces the methodology used to measure the project's idiosyncratic risk. Section 6 discusses the results and the instrumental variable strategy. Section 7 presents the robustness analysis and section 8 concludes.

I. Natural Gas Industry: Institutional Background

A. Project Overview: The Drilling Technology

Two prominent technologies exist to drill natural gas wells: vertical drilling and horizontal drilling (See figure 1). Vertical drilling has been the principal technology in the sample period, representing roughly 89.83% of all the natural gas wells drilled in my dataset. Horizontal drilling technology is more recent and has gradually gained some mainstream appeal only in the later part of the analyzed sample. Furthermore, obtaining precise production forecast for wells drilled using vertical technology is less challenging. Indeed, the number of necessary parameters to observe to make reasonable production forecast is substantially smaller. For example, Covert (2015) provides a great illustration of the high level of detail necessary to properly characterize horizontal wells expected production. Obtaining this level of detail is hardly possible over a long period and across the entire United States. Alternatively, producing good production forecast for vertical wells is possible using information available from major data providers such as Drilling Info. For this reason, focusing on vertical natural gas wells provide a simpler and cleaner way to directly compare projects.

B. Natural Gas Formation Life Cycle

The commercial life cycle of natural gas formation is in two stages: (i) the exploration stage, and (ii) 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[6] and the development stage begins. In the development stage, firms still face a high level of idiosyncratic risk such as not knowing (i) the exact delineation of the natural gas field, (ii) the structure of the rock formation, (iii) the expectation over the production potential of each drilling location, and, (iv) the technical expertise required to optimally extract the resource. For firms drilling wells, these risks translate into tangible operational risks, such as the risk of drilling a dry hole. For example, in figure 2, we see the development of the Panhandle oil field in Texas over the

[6]The American bar association define a proven reserves when 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`

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 50 years later. There are notable differences between the expected and the realized boundary of the field. Large sections that were initially identified as promising appear to have had limited potential ultimately. 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 enough information to form 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.

C. Hierarchical Structure of Natural Gas Firms

Like most firms, oil and gas companies establish their strategy at the upper level of the corporate tree (Graham et al., 2015), but the evaluation and selection of specific projects are mainly conducted by the lower-level managers (Bohi, 1998). For example, upper managers lay the strategies such as designating specific regions of operation, but they tend to leave the detailed works to more junior managers, the geologists and the engineers. Indeed, specific drilling decisions require precise technical expertise and important amount of detailed information that can be best produce by on-site regional teams (Kellogg, 2011; Covert, 2015; Dcaire et al., 2019). For that reason, oil and gas company usually organize their exploration and production activities into regional units (Bohi, 1998). The organization tree of Exxon Mobil exploration and production activities provide a good example of such strategy (See figure 3). Similarly, energy firms' shareholder communication documents provide salient examples of how the geological formations impact firms' structure[7]. By allocating fractions of the firms total budget across multiple managers, this has for effect to increase the investment decision makers (e.g., the junior managers) exposure to the specific outcome of fewer projects. This creates a wedge between the idiosyncratic risk diversification measured at the firm level, and the one measured at the managers' level, potential leading to incongruity in risk preference.

II. Data

I use a dataset provided by DrillingInfo[8] covering the universe of gas wells drilled in the United States for the period ranging from 1983 to 2010 (see figure 4). This dataset includes the monthly

[7]For example, the Devon's shareholders *Operations Report of 2018* Source: `https://s2.q4cdn.com/462548525/files/doc_financials/quarterly/2018/q2/Q2-2018-DVN-Operations-Report-FINAL.pdf`

[8]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.

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 per-foot drilling cost and the estimated operational costs. Also, I augment this dataset with a hand-collected sample from the EIA of 3 years natural gas price forecasts, and two alternative sources of natural gas prices (the Bloomberg natural gas futures contracts, and the EIA wellhead regional natural gas price). Those alternative price sources are used in the robustness analysis section 10. The EIA is a federal reporting agency producing an annual economic analysis for the oil and gas industry[9]. For the public firms in my sample, I augment the dataset with Compustat data. Finally, I augment the dataset with the 10-year risk-free rate available on the Saint-Louis Federal Reserve website, the CRSP weighted market return, the Kenneth French oil and gas industry return[10], the Robert Shiller price-earnings ratio, and credit rating information from Capital IQ to compute firms weighted cost of capital.

I restrict the analysis to firms drilling at least 10 gas wells in a given year. Since I estimate the discount rate from the lower boundary of the firms exercised portfolios, it is reasonable to focus on firms that are minimally active during the year of analysis. Otherwise, it is harder to distinguish between the firms' discount rate and the quality of their opportunity set when applying my revealed preference strategy. Also, I remove the township-year with fewer than 3 wells, because my measure of idiosyncratic risk corresponds to the township-year standard deviation. Computing such measure with a smaller number of observations is not realistic. To ensure consistency across the results of the main analysis, I remove the observations with missing information. Finally, I remove wells for which the initial production date occurs before the drilling date, because it corresponds to a data entry error. Ultimately, the dataset contains 30,420,544 month-well observations used to estimate the well production function for a total of 114,969 distinct gas wells, and 3,946 firm-year-portfolio observations.

Firms in the sample are relatively large, with an average asset value of $229.17 million. On average, the total annual drilling budget is $60.34 million. The average firm invests $11.30 million per year for a given field, or $19.37 million per year for a given state [see table I]. Put together, these numbers indicate that firms in my sample are large, and active in multiple regions. Finally, the average vertical gas well in my sample cost $465,652.90 and produces 570,049 thousand cubic feet of natural gas over its lifetime.

[9]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`

[10]Precisely, I use the oil and gas industry return available in the 49 industries return breakdown. I verified the robustness of the results using the various industries breakdown available on Kenneth French website, and all specifications where the breakdown exist for either the oil and gas industry or the energy industry yield similar results.

III. Firms' Expectations

To recover an estimate of the project expected discount rate, I need an estimate of the firms expectation for the wells' monthly production and the prices at which they expect to sell it, the price of natural gas.

In general, computing the expected quantities independently from expected prices leads to potential biases. In most economic situations, projects expected production flow is correlated with prices [11]. However, in this situation, once the decision to drill the well has been made, the well's monthly production is independent from the state of the economy. Indeed, once a well starts producing managers have little ability to influence the production level without risking damaging it. Effectively, wells' production flow depends on local geophysical parameters such as the local rock type, and the density of the natural gas. For this reason, the wells' production flow is not correlated with the variables affecting gas prices in the global, making the variation of a given well's monthly production flow independent from the fluctuation in gas prices. Thus, independently estimating expected quantities from expected prices should not result in some biases.

A. *Expected Quantities*

Vertical gas wells monthly production can be approximated using a petroleum-engineering model such as the Arp model (Fetkovich, 1996; Li and Horne, 2003). 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:

$$q_{j,m} = A_j(1 + b\theta m)^{\frac{-1}{b}}$$

Where j identifies a specific well, m corresponds to the number of months since the well has been drilled. To estimate the Arp model using a linear framework, I linearize the equation to obtain[12] :

$$ln(q_{j,m}) = \alpha_1 + \alpha_2 + A_j + \sum_{k=1}^{K} \beta_k m^k$$

$q_{j,m}$ correspond the wells monthly production level, α_0 and α_1 are two time dummy variables for the first and second month of production to account for the wells' ramping production[13], A_j correspond

[11] $E[p_m \cdot q_{j,m}] = Cov(p_m, q_{j,m}) + E[p_m] \cdot E[q_{j,m}]$

[12] See appendix C for the full derivation.

[13] Wells ramping period usually corresponds to the first two months of production during which the firms engineers optimize and adjust the well's production to reach peak production (Dennis, 2017). Then, the monthly production gradually declines over time.

to the well's baseline production level, b and β are two decline rate elasticity parameters, m is the age of the well in month, and K is the order of the linear approximation (i.e., 7). The production baseline represents the expected initial quantity of gas produced by the well. I define the baseline production level, as a function the firm total experience (i.e., the total number of wells the firm has drilled at the time of drilling well j), the firm local experience (i.e., the number of wells the firm has drilled in the specific township at the time of drilling well j), the local level of available information (i.e., the total number of wells that have been drilled in the township at the time of drilling well j), a firm-year fixed effect, and a township-year fixed effect such that:

$$A_j = ln(\text{Firms Local XP}_j) + ln(\text{Firms Total XP}_j) + ln(\text{Local Info}_j) + \alpha_{i,t} + \alpha_{p,t}$$

Where i identifies the firms that drilled the well, p identifies the township in which the well was drilled, and t is the year the well was drilled.

Recently, a rich empirical literature both in financial economics, and energy economics suggest that firms own experience, peer's effects, and local access to information influence the quality and the type of projects a firm will endeavor (Covert, 2015; Dcaire et al., 2019; Hodgson, 2019). More experienced firms are more likely to produce high quality wells or identify regions with better potential. Equally, regions with more activity are more likely to have wells of higher quality, while at the same time, having more precise information about how to best extract the resource. Since the goal of this part of the analysis is to both obtain precise estimates of the wells expected production flow and a reasonable measure of the wells idiosyncratic shock it is important to controls for these dimensions of the firms.

I use the Arp model to estimate expected production flow of the wells, using a sample of 30,420,544 month-well observations [see table II]. Figure 5[14] provides a graphical illustration for the median well production function over time and contrasts it with the estimated production output. The figure also includes the empirical decline curve of wells producing at the 10th and 90th percentile in the sample. Strikingly, the decline curve of the median wells, but also the wells on the extreme margins of the production spectrum, decline in a similar fashion.

I use the estimated well production function parameters to obtain an estimate of the managers' wells' monthly gas production. A striking feature of gas production function pertains to the depletion rate. The speed at which the gas is extracted 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 5). Effectively, the pressure usually reduces as wells get older, making the depletion rate to steadily decline over time.

[14] I exclude the ramping up period (i.e., the first 2 months of production) to present the well production decline from peak production on this figure.

B. *Expected Price*

I measure the expected gas prices using the Energy Information administration (EIA) 36-month natural gas price forecast. The EIA forecast is closely followed by governmental organization, financial institutions, and energy companies. In the robustness section 10, I explore how the use of Bloomberg natural gas futures prices, and wellhead spot prices varying at the states level impact the results. I favor the EIA over these alternative price specifications for two reasons. First, the EIA forecast has been consistently published since 1983, while the 36-month natural gas futures started traded only in 1995. This enables me to extend my analysis over a longer period. Second, while the wellhead states prices provide me with price variation across state during a given year, it fails to account for managers expectation of price variation. Finally, I focus on the 36-month forecast because the projects discounted half-life[15] in my sample is 31 months.

IV. Estimating Firms' Discount Rate

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 agents normative preference (the agent's actual interests) and the observed preference (the agent's interests that rationalize the observed actions). Multiple factors can affect the disparity between the two preferences, notably (i) the nature of the decision process (active versus passive decision-making), (ii) the complexity of the decision rule, and, (iii) the agents experience (Beshears et al., 2008). In this study, firms actively make the decision to invest in projects that maximize the net present value (NPV), a simple decision rule. The median firm in the sample drills 49 wells per year, indicating a reasonable level of experience. I detailed the methodology used to obtain an estimate of firms' discount rate in the next two subsections.

A. *Estimating Projects' Expected Rate of Return*

In the first step, I compute the implied expected rate of return (μ_j) of each project j such that:

$$\sum_{m=1}^{M} \frac{1}{(1+\mu_j)^m} \mathbb{E}[q_{j,m} P_m] - C_j = 0$$

Where μ_j corresponds to well j monthly expected rate of return, $\mathbb{E}[q_{j,m}]$ corresponds to the expected monthly production for well j at age m months[16], $\mathbb{E}[P_m]$ corresponds to the expected price

[15] 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.

[16] I adjust the expected quantities from the Arp model for the probability of having no production during a given month. Adjusting for the probability of no production is necessary since the Arp regression uses the natural logarithmic value of the well production, thus excluding production event equal to 0. Precisely, $\mathbb{E}[q_{j,m}] = \mathbb{E}[q_{j,m} *$

managers receive net of the operational cost and royalty rate[17], and C_j corresponds to the initial drilling cost incurred when the well is drilled. Finally, the average well in my sample produces for 264 months (i.e., M=264). This strategy provides me with an estimate of the internal rate of return for each project in my sample.

Calculating projects internal rate of return can, in some situations, have complications. If the projects cash flows change sign multiple times during the projects life cycle, I could obtain multiple estimates of the expected rate of return. 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 can be reasonably assumed to be proportional to the projects cash flow. Thus, this issue should not affect my calculation.

B. Estimating Firm-Year Discount Rate

In the second step of the revealed preference strategy, for all the wells a firm completes in a given year, I split the wells into two portfolios based on their level of idiosyncratic risk. Projects with a measure of idiosyncratic risk above (below) the firm-year median are put in the high (low) idiosyncratic risk portfolio. Finally, for both firm-year portfolios, I estimate the discount rates as the lowest expected return among the projects undertaken for each portfolio, respectively. The logic is that the firm's discount rate for that risk profile must be at least this low; otherwise these projects would not have been undertaken.

Estimating the discount from two firm-year portfolios provides me with multiple benefits. First, it enables me to build a measure of firm-year price of idiosyncratic risk, to directly test its effect on firms performance in section 8. Second, it enables to control for firm-year factors in my regression specification. However, to show that my results are not sensitive to this experimental design choice, I provide an alternative specification where I estimate the discount rate from one portfolio per firm-year in section 10.

In this study, I only observe the set of projects each firm completes in a given year. In other words, I observe a truncated distribution of the projects expected internal rate of return, because it is not possible to systematically observe the expected return for all the projects the firms did not pursue. Realistically, most projects a firm undertakes have positive net present value (i.e., the NPV is greater than zero), because managers invest in all projects for which the expected internal rate of return is above the firms discount rate, indicating that on average the project internal rate

$(1 - Pr(\text{zero production in month } m))]$. I follow the methodology presented Covert (2015) to adjust the production estimates for the zero production events. Precisely, I estimate a linear probability model to estimate the probability of having a no-production event, such that probability of a month with zero production is 0.028 in the first year, 0.029 in the second year, 0.031 in the third year.

[17] $\mathbb{E}[P_m] = \mathbb{E}[\text{Gas Price}]$ * (1- Royalty - Operational Cost)

of return would be greater than the firms discount rate.

To validate that my estimate captures the main features attributed to firms discount rate, I conduct two validity tests. First, I restrict my analysis to the subset of firms for which I observe the full capital structure and the credit rating. For those firms, I compute the weighted average cost of capital (WACC). To obtain an estimate of the cost of equity, I first estimate the one-year oil and gas industry capital asset pricing model (CAPM) beta at the monthly frequency, using Kenneth French industry return data. Then, to finally obtain the price of equity, I multiply the industry beta with the earnings-over-price ratio net of the risk-free rate, obtained from Robert Shiller website. Finally, to obtain the cost of debt, I obtain the firms most recent credit rating from Capital IQ (See Appendix A.2.). Columns 1 to 4 of table IV present the results of those regression specifications. There exist a reasonable and statistically significant relationship between the discount rate estimates and the component of the WACC as well as between the discount rate estimates and the WACC. Coefficient β_2 indicates that a one-unit shock to the firm WACC results in a 1.14% to 1.27% increase in the discount rate[18]. The results presented in columns 3 and 4 suggests that the idiosyncratic risk premium is added to the discount rate on top of the WACC. The results presented in table IV indicate that the discount rate measure behave in a consistent fashion with the firms cost of capital.

For the second set of tests, I extend the analysis to the full set of observation. However, because I do not observe the full capital structure for all my firms, I focus on how the discount rate covaries with the cost of equity. Finally, for this specification, I subtract the risk-free rate from the discount rate estimate. In this first specification, I am using the entire sample including the firms for which I do not observe the full capital structure. Columns 5 to 8 of table IV present the results of the test. The coefficient β_1 captures the relationship between the cost of equity and my estimates of the firms discount rate. I find that there exist a positive and statistically significant relationship between the cost of equity and my estimate of the discount rate. In terms of economic magnitude, a one-percent increase in the cost of equity corresponds to an increase between 0.97% and 1.95% of my discount rate estimate. Although, this regression is incomplete because the industry cost of equity does not fully capture firms true cost capital, it provides results that are qualitatively consistent with the WACC regression for my entire sample.

V. Measure of the Well's Idiosyncratic Risk

To construct the *Projects Average Idiosyncratic Risk* variable, I proceed in three steps. First, I define the wells idiosyncratic profitability shock as the ratio of the first year cash flow forecast

[18] In all specifications, the value of 1 is included for the coefficient β_2 confidence interval.

error on the well's drilling cost such that:

$$\zeta_j = \frac{\sum_{m=1}^{m=12} p_m * q_{j,m} - \sum_{m=1}^{m=12} \mathbb{E}[p_m * q_{j,m}]}{Cost_j}$$

Second, for each township-year subset, I define the idiosyncratic risk measure by computing the cross-sectional dispersion of the wells idiosyncratic profitability shocks. This provides me with a measure of idiosyncratic risk at the township-year level, that I can attribute to each well that was drilled in the specific township, on that given year. Finally, to obtain a measure for the firm-year-portfolio level, I take that average of the projects idiosyncratic risk.

Focusing on the first-year idiosyncratic profitability shock is naturally appealing. First, it corresponds to the level of profitability uncertainty managers' face, for 1$ of invested capital in the first year. Small value indicates that for each invested dollar, the managers face little uncertainty regarding the profitability of the well, while large value indicates that each invested dollar is exposed to a greater deal of uncertainty. Second, firms tend to pay close attention to the information generated by the drilling outcome of the geographic peers in those wells early months of production, suggesting that updating the measure of idiosyncratic risk every year likely capture features of the idiosyncratic risk sensed by managers. Third, the analysis is conducted at the yearly frequency. Thus, it enables me to work with a measure of risk that is computed at the frequency of the analysis.

Finally, the information contained in the well's idiosyncratic profitability shock (i.e., ζ_j) is plausibly orthogonal to the firms characteristics. The Arp regression controls include a firm-year fixed effect, a township-year fixed effect as well as the firms local experience, the firms global experience, and the available amount of local information at the time of drilling. Thus, the information contained in the wells idiosyncratic profitability shock likely corresponds to information that is orthogonal to the firm-year and geographic characteristics.

To verify the validity of the Arp regression specification, I first test see if there is any spatial correlation of these wells production forecast error. My goal is to make sure that the variation in the forecasting error is not driven by other important spatial-economic factors omitted from the conditioning information in the Arp model. I measure spatial correlations using the Moran's I. The Morans I coefficient values range between 1 and -1. A coefficient equal to zero indicates no spatial correlation, while positive coefficients implies clustering of forecasting errors. In the context of my analysis, this would suggest that the Arp model has omitted spatial factors. My estimate of the Morans I coefficient is close to zero (i.e., 0.01) suggesting that the Arp model captures the spatial factors adequately.

Finally, to validate that my measure of idiosyncratic risk is effectively related to greater occurrence of bad drilling outcomes, I first look at the number of dry holes in the township-year,

conditioning on my estimates of idiosyncratic risk. For the township-year in the upper (lower) half of the idiosyncratic risk distribution, there is on average 0.39 (0.04) dry holes drilled. This corresponds to a one-order of magnitude difference between the two subgroups, suggesting that the township-year with a greater level of idiosyncratic risk effectively experience more bad drilling outcomes. To control for additional elements, I also estimate a Poisson regression[19]. Table III reports a positive and statistically significant relationship between the projects idiosyncratic risk and the probability of drilling a dry hole across all specifications. This result provides empirical support for the relationship between the measure of idiosyncratic risk and adverse drilling outcomes.

VI. Results

A. *Do managers price idiosyncratic risk?*

I begin by directly testing if managers price idiosyncratic risk. Specifically, I regress firms discount rate on projects idiosyncratic risk. The unit of observation is at the firm-year-portfolio level[20]. Table V shows that idiosyncratic risk appears to be positively priced by managers. Column (1) present the simple regression, with no additional controls. Columns (2) to (6) introduce a set of controls and show that the regression results in robust to these specifications. Column (7) in include a firm-year fixed effect, to control for firms characteristics that are time varying. The source of variation in this regression specification comes from the relationship between the level idiosyncratic risk and the estimated discount rate of the two firm-year portfolios. To facilitate the interpretation of economic magnitude of the coefficient of interest across all tables presented in this paper, I scale the variable *Projects' Average Idiosyncratic risk* by its standard-deviation to directly obtain the effect of a one-standard-deviation increase on the discount rate[21]. Then, for the average firm, a one standard-deviation increase in idiosyncratic risk results in a 7.80% to 12.68% increases of the discount rate. I address the potential concerns regarding the limitation of the revealed preference strategy, such as the effect of real options, in the robustness section 10.

B. *Instrumental Variable*

In this study, I measure the price of idiosyncratic risk by looking at the discount rate of two portfolios (both with different exposure to idiosyncratic risk) computed at the firm-year level. To control for potential omitted variable problems, my favored specification includes a set of firm-year fixed effect. However, if within-firm unobservable characteristics, such as managers experience or managers preference are correlated with projects idiosyncratic risk, this would potentially bias my

[19] A Poisson regression is the appropriate model when the dependent variable is a count, such as the number of dry holes in a township-year (Greene, 2003).

[20] Discount $\text{Rate}_{i,t,k}$, where i corresponds to the firm index, t corresponds to the year, and k corresponds to whether the observation is from the high or low idiosyncratic portfolio.

[21] Scaling the variable by a constant only affects the size of the regression coefficient, but not its statistical properties (Greene, 2003).

estimates, even after conditioning with controls and a firm-year fixed effect. To be concrete, this could be a problem if more experience managers systematically get assigned to riskier fields, or vice versa. Alternatively, if managers assigned to riskier fields have different expectations on natural gas prices. In this situation, my fixed effects strategy would not be enough to deal with the endogeneity problem.

To mitigate the omitted variable endogeneity concerns, I complement the fixed effects with an instrumental variable approach. To instrument for the projects idiosyncratic risk, I use the firms peers largest idiosyncratic profitability shock in their township for every given year. Figure 6 provides a graphical example of how these shocks are identified. Practically, for each firms well in my sample I find the largest idiosyncratic profitability shock experience by their peers, in the wells township-year. Then, I define the instrumental variable as the average value of those peers shocks for each firm-year portfolios.

First, to understand how the instrument variable satisfies the relevance condition, it is useful to remember that the measure of projects idiosyncratic risk corresponds to the cross-sectional dispersion of all the idiosyncratic profitability shocks occurring at the township-year level. Thus, this measure is a function of all the individual idiosyncratic profitability shocks happening at the township-year level. It is reasonable to assume that the firms peers largest township-years idiosyncratic shock is likely to be mechanically correlated with this measure of risk. Panel A of table VI reports the first stage of the instrumented regression. First, the coefficient β_1 indicates that empirically, there exist a positive relationship between the peers largest idiosyncratic profitability shock and my measure of idiosyncratic risk. Second, to address the weak instrument concern, the bottom section of panel A reports the Kleibergen-Paap first stage f-statistic. For each regression specification, the statistics are substantially greater than the minimum threshold (i.e., $\sim$10) to test for weak instruments.

Second, to address the exclusion restriction I turn to the information content included in the projects idiosyncratic profitability shocks. The shocks are orthogonal to township-year characteristic, the firms local experience, the firm global experience, the local information and the other characteristics associated to the township-year (Section 4 provides a full discussion on the idiosyncratic shocks calculation). For example, if managers characteristics affect their assignment to specific townships, such as their level of experience, the set of controls included in the Arp model should reasonably account for this dynamic.

Panel B of table VI reports the second stage results of the instrumented regression. The second stage results are slightly smaller than the one obtained in the reduced form regression, but the magnitude remains economically meaningful. For the instrumented regression, a one-standard-deviation increase in the projects idiosyncratic risk results in an increase between 5.23% and 10.45%

in the firm discount rate.

C. Idiosyncratic Risk Premium and Firms Performance

The classical corporate finance literature recommends that managers should not adjust their discount rate. Failing to follow the literature recommendations could result in assets misallocation. As a consequence, pricing idiosyncratic risk should have negative consequence of firms performance. However, aside from the direct theoretical recommendation, the existing literature lack empirical evidence to relate idiosyncratic risk pricing to adverse consequence to firms performance.

To directly test for the effect of idiosyncratic risk pricing on firms performance (e.g., gross profit margins, gross profitability, asset growth (YoY), and investment rate), I introduce a measure of firms price of idiosyncratic risk, to use as my independent variable. To construct this variable, I define the numerator as the difference of the discount rate between the high idiosyncratic risk portfolio with the low idiosyncratic risk portfolio, and the denominator as the difference of the projects idiosyncratic risk measure of the two portfolios[22]. Precisely, this measure is the discount rate increase for a one-unit increase in projects idiosyncratic risk, for each firm at a yearly frequency.

Table VII reports the results of this section analysis. I find that for the average firm, a one standard-deviation increase in the price of idiosyncratic risk has sizable negative consequences on firms gross profit margins (-5.05%), profitability (-0.51%), investment rate (-0.75%) and year-over-year asset growth (-0.81%). The negative relative relationship between firms performance and the firms price of idiosyncratic risk suggest that idiosyncratic risk pricing is related to a form of resource misallocation.

D. Mechanisms

I investigate two potential mechanisms to evaluate how and why managers account for idiosyncratic risk in their discount rates. Various theories support the existence for external channels (frictions between the firms and the financial market) and internal channels (frictions between managers and their superiors).

D.1. Costly of External Financing and Idiosyncratic Risk Pricing

Firms dispose of multiple tools to manage their exposure to risk. While most of the discussion in the literature has focused on the use of financial derivative, other mechanisms have long been acknowledged. Studying the interaction between risk management and capital budgeting, Froot

[22]The calculation details are available in appendix A.1.

et al. (1993) make empirical prediction that managers would adjust their discount rate to account for risk that cannot be offloaded in the financial market in the presence of costly external financing. Risks that cannot be hedged expose the firm to variability in cash flows. In the context of this paper, this can be understood as drilling wells that would not produce natural gas (e.g., a dry hole). If the projects the firms pursue fail to produce cash flow, the firms must then turn external markets to raise additional funds and continue its operations. However, if the cost of marginal funds increases with the amount raised, the firm will have to limit its investment in the next period. In this sense, greater variability in the wells' outcome exposes firms to greater probability of having to raise external funds at a premium. Since this source of risk directly translate into greater capital cost, Froot et al. (1993) suggest that managers should adjust their discount rate calculation.

Obtaining a measure of the cost of external financing is challenging, researchers do not directly observe this variable. To empirically test Froot et al. (1993) hypothesis, I build on the empirical work of Hennessy and Whited (2007). In their analysis, they provide empirical guidance to select the best proxy of costly external financing. The core of their analysis focuses on four measures: (i) the Cleary index, (ii) the Whited-Wu index, (iii) the Kaplan-Zingales index, and firms size. They conclude that firms size is the best variable to proxy for the costs of external financing, where larger firms face lower cost of external finance than their smaller counterpart. Indeed, they find that the Cleary index and Whited-Wu index, properly capture most of the dynamics attributed to the cost of external financing, but failed to behave adequately with bankruptcy cost, making them an overall inaccurate measure to proxy for cost of external funding. Finally, the authors note that the Kaplan-Zingales index improperly capture most of the dynamics attributed to the cost of external financing. The authors concluded that firms size is the best variable to proxy for costly external financing, noting that the three indexes are better suited to proxy for the need of external funding. To make the analysis transparent, I also include the three indexes in alternative specifications. Finally, I include a final specification with the firms public/private status, using a dummy variable equal to one if the firm is private, and zero otherwise. Private ownership status has been associated with higher financing frictions in the finance literature (Gao et al., 2013).

Tables VIII to XII presents the results of the five proxies of costly external financing. For each table respectively, the coefficient β_2 measure the effect of costly external financing on firms price idiosyncratic risk. Columns 5-8 of the tables present the instrumented results where two variables are instrumented; the projects average idiosyncratic risk variable, and the interaction term of projects average idiosyncratic risk with the costly external financing proxies (i.e., β_1 and β_2).

Table VIII reports the results of firm size. Consistent with the analysis of Froot et al. (1993), I find that as the cost of external funding decreases, firms price idiosyncratic risk less aggressively. The results are robust across all specifications, for both reduced form and the instrumented regression. On average, a one-standard-deviation reduction in firm size results in an increase between

2.423% and 3.150% for the price of idiosyncratic risk. Specifically, columns (3), (4), (7) and (8) introduce a proxy for firm diversification[23]. I include this variable, because size is associated with firms' ability to diversify idiosyncratic risk away (Demsetz and Strahan, 1997). Larger value of this variable indicates that idiosyncratic risk is more diversified at the firm level.

Table IX presents mixed results for the effect of firms ownership status. For the specification excluding a firm fixed effect, I obtain dynamics that are consistent with the prediction of Froot et al. (1993), such that private firms price idiosyncratic risk more than public firms, but the difference is not statistically significant. Tables X and XI report the Cleary and Whited-Wu index results. They are directional consistent with the theoretical prediction developed in Froot et al. (1993), but they are not statistically different from zero. Also, table XII reports the results of this test for the Kaplan-Zingales index. The Kaplan-Zingales produce results in opposition to the prediction in Froot et al. (1993). However, Hennessy and Whited (2007) analysis suggests that the Kaplan-Zingales has the worst performance when trying to capture the cost of external funding, among the proxies discussed in this section.

Overall, the results presented in this section suggest that firms cost of external finance can have a meaningful impact on how firms adjust their capital budgeting policies. Focusing on Hennessy and Whited (2007) favored measure, I find that costly external financing can induce managers to price idiosyncratic risk. While the additional proxies tested in this section do not provide results that are statistically significant, the nature of the effect in those specification is at least directionally consistent with the theoretical prediction.

D.2. Managers Budget Size Diversification and Idiosyncratic Risk Pricing

Survey evidence collected by Graham et al. (2015) suggests that specific investment decisions are formulated at the lower level of the hierarchical tree, while budget allocation is decided by the firms superiors. Geanakoplos and Milgrom (1991) 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., Caroli and Reenen (2001); Colombo and Delmastro (2004); Acemoglu et al. (2007)), where workers in jobs that require technical skills usually benefit from a greater level of authority. In the context of gas exploration and production company, this approach increases the likelihood that people most familiar with the local rock formation specificity will make investment decisions with limited interference. However, the decoupling between the capital allocation choice and the decision to investment in specific projects, the delegation process, has been argued as a potential source of agency conflict between the managers and its superiors (Aghion and Tirole, 1997).

[23] Appendix A.1. provides the calculation details

A direct consequence of the delegation process implies that firms superiors allocate a fraction of the firm total budget across multiple managers, each tasked to evaluate and select projects to maximize the firm value. The fact that managers receive a fraction of the firms budget can result in a loss of diversification at the managers level in the sense of Diamond (1984). For a risk-averse manager, if the projects idiosyncratic shocks are not perfectly correlated, a larger budget has two effects: (1) it reduces the total quantity idiosyncratic risk they face, and (2) it decreases the managers idiosyncratic risk premium. Diamond (1984) intuition predicts that firms for which managers have a larger budget should, all things equal, price idiosyncratic risk less aggressively.

To directly test this hypothesis, I first construct a measure of managers' annual budget size. Exploration and production gas companies organize their activities into regional business units. Although it is difficult to directly observe the exact region covered by each manager, I construct two proxies of the managers budget, based on plausible definitions of region of activity. Indeed, looking at firms job posting[24] and when possible firms organization trees, oil and gas companies appear to organize their unit on at a geographical scale. It is then possible to create reasonable measure of the managers budget. Precisely, I assume two potential scenarios such that managers can either be individually assigned to a specific field or a specific state. Assuming that managers are assigned to specific fields constitutes a reasonable assumption, as each field possesses unique characteristics for which the necessary expertise can hardly be directly applied into other fields (Kellogg, 2011). These particularities imply a steep learning curve, limiting managers' ability to easily transfer their knowledge in a given year. At the other extreme, using states as the managers assigned territory represents a plausible upper boundary, since job postings and firms organization trees generally identify regions of activity at the state level, at most (see figure 3). For these two specifications, I define the managers budget size in two steps. First, I measure the total cost of the wells drilled in a given field or state for each firm and year. Then, I take the average at the firm and year level. This provides me with the average budget size of the firms managers on that given year.

Table XIII presents the results of the regression specification using the fields as the managers' region of activity. Coefficient β_2 measure the effect of managers budget size on firms price idiosyncratic risk. In line with Diamond insight, I find that managers budget size diversification has a meaningful impact on the firms price of idiosyncratic risk. On average, a one-standard-deviation increases in firms average managers budget results in a reduction between -1.131% and -0.621% in the price of idiosyncratic risk. Tables XIV reports the results for this section using states as the manager's region of activity. The results are robust to this alternative specification. Finally, table XV shows a positive and statistically significant relationship between managers budget size and individual projects level of risk. This suggests that managers risk appetite increases as a result of increasing their budget size.

[24] Example of projects' manager's job description are available on `https://www.rigzone.com/oil/jobs/postings/`

To provide further evidence in support of the agency channel, I test to see if the effect of managers' budget size is more salient in firms experiencing more agency problem. To obtain a measure of agency, I build on the insight that proximity facilitates monitoring and information acquisition for the firms owners or superiors. A rich literature present evidence illustrating the benefits of proximity in reducing the cost of acquiring information and improving monitoring. Giroud (2013) present evidence suggesting that proximity between firms' headquarters and plants reduces agency conflict by improving the ability of superiors to directly monitor plants' managers. Similarly, Coval and Moskowitz (1999) and Coval and Moskowitz (2001) show similar results with mutual fund managers, where proximity enables them to obtain better results with the shares of firms located geographically closer, suggesting better monitoring capabilities and access to private information. My measure of proximity is obtained by calculating the median distance between the wells drilled by a firm in a given year[25]. In the context of this literature, a greater median distance between the firms' wells indicates greater difficulty for the superiors and the firms owners to directly monitor the quality of the projects, thus a greater level of agency problem. Then, if budget size affects managers risk preference through the agency channel, one would expect that effect of budget size will be more salient in firms experiencing greater agency. Table XVI reports the result of this additional test. The variable of interest is associated with the coefficient β_3. The negative coefficient suggest that as firms face more agency problem (i.e., a greater distance between the wells) the effect of budget size in mitigating the agency friction becomes stronger.

The results of this section suggest that managers budget size has a meaningful effect in reducing managers' exposure to projects idiosyncratic realization, ultimately reducing managers price of idiosyncratic risk. It suggests that for the average firm, the set of available tools to alter managers risk preference extends beyond compensation contract. By shifting the allocation of resources among its managers, firms can provide some form of insurance to its managers against projects' specific realization.

VII. Robustness Analysis

I conduct several robustness tests to ensure that my results reflect the discount rate adjustment for the exposure to idiosyncratic risk.

[25] In a first step, I measure the distance between all the wells a firm drilled in a given year. Then, I take the median value of those distances.

A. The Effect of Real Options

A potential concern with my strategy to estimate the firms discount rate is whether I fail to account for important aspects of how firms select which project to pursue. Instead of using the wells cost to compute the projects net present value, managers could use a real option investment threshold. In the context of my analysis, improperly assuming managers' valuation strategy, could have an important implication on the interpretation of my results. Indeed, real option optimal exercise threshold (Dixit and Pindyck, 1996) is a function of the idiosyncratic risk. In this sense, failing to account for the optionality value of the firms investment opportunities could affect my main result.

Empirical evidence suggests that managers behave in a way that is consistent with the real option theory (Bloom et al., 2007; Kellogg, 2014; Dcaire et al., 2019), although they systematically exercise their investment opportunities significantly before the real option recommendation. Brennan and Schwartz (1985) in the case of gold mines, Kellogg (2014)[26] in the case of crude oil wells, and Dcaire et al. (2019) in the case of shale gas wells provide micro-level empirical evidence in support of this claim. This suggests that managers do not strictly follow the recommendation of the real option theory, as documented in multiple survey studies (Graham and Harvey, 2001; Jacobs and Shivdasani, 2012; Graham et al., 2015). Rather, managers report to favor straightforward and less capricious valuation strategies such as the net present value (NPV) or the internal rate of return (IRR) to select projects in more than 90% of the cases (Graham and Harvey, 2001). In this light, it is reasonable to assume that managers acknowledge to some extent the value and importance of operational flexibility, but real option models might be too stylized to properly capture the full dynamic. However, to provide results robust to the real option effect, I introduce two empirical strategies.

First, to directly alleviate the concern that my analysis is biased by a real option factor I run the analysis on a restricted sample of projects that have limited operational flexibility. Indeed, real option value depends on the project timing flexibility; the more time the managers have to decide when to invest in their projects, the more the real option is worth, all things equal. In the United States there are two ways a firm can possess the right to develop a plot of land. First, the firms can acquire a lease, providing them with the exclusive right to the plot of land during a certain period. On average, a lease duration is three years. Second, firms can "hold by production" the development rights. This means that for as long as the firms has a producing well on the plot of land, they are entitled to further develop it to fully deplete the gas reserves. Usually, firms have 20 years or more to develop their plot of land in those cases. Papers investigating real option behavior have traditionally focused on the wells with plots of land that are held by production, because the real option phenomenon is more salient in those cases (Dcaire et al., 2019). However, empirically in the case with leased plot of land, oil and gas exploration companies tend to drill their first well just

[26] See figure 10 of Kellogg (2014).

a moment prior to the lease expiration (Herrnstadt et al., 2019), when the operational flexibility is limited. For those first wells, the effective value of the option-to-wait at the time of drilling is marginal. Indeed, as the option time to expiration converges toward zero, the value of the options also converges to zero. Thus, my first strategy limits the analysis to a subset of wells that are the first to be drilled on a given plot of land.

In the second specification, I adjust my revealed preference strategy to directly account for the real option value. Precisely, I modify the managers decision rule, when estimating each project expected internal rate of return. Instead of assuming that firms decide to invest in a project whenever the project expected cash flow is greater than the project cost, I assume that firms use a real option optimal exercise threshold[27]. The real option optimal threshold is increasing in the projects' level of idiosyncratic risk. A potential limitation of this strategy pertains to the amount of time to expiration for each well. I do not observe this information for most of the observations in my sample. Thus, to produce conservative results I assume firms have an infinite time horizon to exercise their projects. This assumption is conservative, because real option optimal threshold is increasingly sensitive to projects risk as the time to expiration increases (Dixit and Pindyck, 1996).

Table XVII and XIIX respectively report the result of the robustness test for the real option effect. Both regression specifications present results that are qualitatively and statistically similar to my main results, suggesting that a real option effect is not fully affecting my result. Not surprisingly, the estimated coefficients are lower in all specification, suggesting that some of the observed phenomena could be partially attributed to a real option effect. Also, the number of observations in table XIIX is lower than in the main regression table, because most of the projects evaluated in my analysis are infill wells (i.e., wells drilled when the plot of land is held-by-production). Finally, to test the robustnes of my results with the calibrated real option, I design a kill test. Precisely, when calibrating the real option optimal threshold, I increase the measure of idiosyncratic risk to find at which level my core result is no longer statistically significant. Multiplying my value of idiosyncratic risk magnifies the difference between the riskier wells and the less risky ones, ultimately widening the difference between the real option exercise threshold, which reduces the difference between the estimated IRRs. Ultimately, I find that I would need to magnify the difference between my measure of idiosyncratic risk by 28.8% to eliminate my main result in the real option specification.

B. The Effect of Firms Leverage

The firms cost of debt increases with the total amount risk measured at the firm level (Merton, 1974); systematic and idiosyncratic risk included. Taksler (2003) present empirical evidence in favor of Mertons theory. This suggests that firms weighted cost of capital should price firms idiosyncratic

[27] I use Dixit and Pindyck real option optimal threshold (V^*) such that $V_j^* \geq C_j$. Appendix 3 provides the calibration detail for the real option calculation.

risk, through its debt component. For most firms in my sample, my measure of idiosyncratic risk is not perfectly diversified at the firm level, suggesting that it is probably price by their debt. To test for this alternative specification, I include firms book leverage and an interaction term of book leverage with project-level idiosyncratic risk in my regression specification. In conduct this analysis for the subset of firms for which I can measure the book leverage. Table XIX reports the results of this test. Consistent with the effect of leverage discussed in Merton (1974), the interaction term between firms leverage and the projects average idiosyncratic risk (i.e., β_5) is positive. However, my estimates for the price of idiosyncratic risk are not economically or statistically affected by this alternative specification.

C. Alternative Price Specification

I verify that my results are robust to two alternative price specifications. In the first alternative price specification, I use the 36-month Bloomberg natural gas futures contract prices. Table XX reports the results of this specification[28]. In the second specification, I use the EIA regional wellhead prices to account for price heterogeneity across states (See figure 6). Effectively, the price firms obtain for selling their product can vary across regions, depending on the quality of the resource, and the distance it takes to be transported to a refinery site. Table XXI reports the results of the regional price specification. In both cases, the main results are not qualitatively and quantitatively altered.

D. Alternative Experimental Design

Finally, to address the concern that my analysis is affected by the specific nature of my experimental design, I use an alternative design specification. Instead of constructing two portfolios for each firm-year subsample, sorted on the idiosyncratic risk exposure of the projects, I work with only one portfolio per firm-year subsample. Table XXII reports the regression results when estimating the discount rate with this approach. The coefficient estimates are not meaningfully affected by this alternative experimental design. Effectively, coefficient β_1 lies within the confidence interval of my estimates in table V. The only practice difference is that I cannot include the regression specification that uses the firm-year fixed effect, as I only have one observation per firm-year.

VIII. Conclusion

In this paper, I analyze the relationship between projects idiosyncratic risk exposure and firms project-specific discount rate. My results establish that managers positively adjust their discount rate to account for idiosyncratic risk. Also, I provide empirical evidence suggesting that pricing

[28]The number of observations is smaller than the main specification of the sample, because 36-month natural gas futures prices are only available from 1995 the 2010 on Bloomberg. Thus, limiting the sampling period.

idiosyncratic risk appears to negatively affect firms performance. This is evidence in favor of the classic corporate finance recommendation suggesting managers not to adjust their discount rate for idiosyncratic risk. Further, consistent with risk management theory, managers appear to adjust their discount rate calculation to account for their exposure to unhedgeable risk, when facing costly external financing. Finally, I find that capital budgeting policies, such as the size of managers budget appears to provide firms' owners with an additional lever to insure managers to projects specific outcomes and better align their risk preference.

An interesting implication of these results is the role of alternative tools to align managers' preference. Most of the theoretical and empirical work in finance focuses on compensation contracts as the main nexus to insure managers in the firm. Similar to the theoretical insight of Holmstrom and Costa (1986), I find that capital budgeting policies, such as the size of managers' budget, can supplement the set of available tools to achieve this goal. More work focusing on how capital budgeting practices can be used as a complement to well-known risk sharing mechanism would have great benefits for academics and practitioners alike. In an era when most companies increasingly discuss the virtues of independent small units and the benefits of decentralization to organize the firms' portfolio of projects (McDowell et al., 2016), considering the potential distortion of such strategy is primordial.

My hope is that this paper with help generating greater interest in the analysis of the interplay between capital budgeting policies, risk management, and the organization of the firms. Finally, I hope that the results of this paper will help a future generation of managers to be more conscious about the consequences of adjusting the projects' discount rate for idiosyncratic risk and help them design better corporate policies to minimize the size of the distortions.

Appendix A. Variable Definition

In this appendix, I define how each variable discussed in the paper is constructed. Subscript i corresponds to a specific firm, t corresponds to the year, j indicates a specific well, f refers to a field or a state, p refers to a township, and k refers to the two portfolios at the firm-year level sorted on the idiosyncratic risk. A subscript with a minus sign such as X_{-i}, would indicate that the firm own observations are excluded from the observations used in the calculation of the specific variable.

Appendix A.1. Gas Well Variables

1. # of Wells in a Township-Year: $\mathrm{N}^{j}_{p,t}$ = Count the number of projects per township p and year t
2. # of Active Region: $\mathrm{N}^{f}_{i,t}$ = Count the number of fields or states the firm is active in during the year
3. # of Projects per Firm-Year Portfolios: $\mathrm{N}^{j}_{i,t,k}$ = Count the number of projects per firm i, Year t, and Portfolios k
4. Cost_j = The drilling cost of well j
5. Township-Year Average Well's $\mathrm{Cost}_{p,t} = \frac{\sum_{p,t} Cost_j}{N^j_{p,t}}$
6. $\mathrm{Asset}_{i,t} = \sum_i Cost_j$, for all producing wells on year t for firm i
7. $\mathrm{Budget}_{i,t} = \sum_{i,t} Cost_j$, for all the wells drilling on year t for firm i
8. Managers' $\mathrm{Budget}_{f,i,t} = \sum_{f,i,t} Cost_j$, for all the wells drilling on year t for firm i in field or state f
9. Average Managers' Budget at the Firm $\mathrm{Level}_{i,t,f} = \frac{\sum_{i,t} \text{Managers' Budget}_{i,t,f}}{N^j_{i,t,f}}$
10. Natural Gas $\mathrm{Price}_t = P_t$
11. Operational Cost (%) $= OP$
12. Royalty Rate_t (%) $= R_t$
13. Yearly Gas $\mathrm{Production}_{i,t}$ (in 1,000 cf) $= Q_{i,t}$
14. Operating $\mathrm{profit}_{i,t} = P_t Q_{i,t} * (1 - R_t - OP) - Budget_{i,t}$
15. Gross Profit $\mathrm{Margin}_{i,t}$ (%) $= \frac{OperatingProfit_{i,t}}{P_t Q_{i,t}} * 100$
16. Gross $\mathrm{Profitability}_{i,t}$ (%) $= \frac{OperatingProfit_{i,t}}{Asset_{i,t}} * 100$
17. Assets $\mathrm{Growth}_{i,t}$ (YoY) (%) $= \frac{Asset_{i,t+1}}{Asset_{i,t}} * 100$
18. Investment $\mathrm{Rate}_{i,t}$ (%) $= \frac{Budgeti,t+1}{Asset_{i,t}} * 100$
19. Discount Rate: $\mathrm{DR}_{i,t,k}$ = Lower bound of the firm-year portfolio IRR distribution.
20. Project's profitability shock: $\zeta_j = \frac{\sum_{m=1}^{m=12} p_m * q_{j,m} - \sum_{m=1}^{m=12} \mathbb{E}[p_m * q_{j,m}]}{Cost_j}$
21. Township-Year Idiosyncratic Risk: $\mathrm{IR}_{k,t} = = \frac{1}{N^j_{p,t}-1} \sum_{p,t} (\zeta_j - \bar{\zeta}_{p,t})^2$
22. Projects' Average Idiosyncratic Risk: Average $\mathrm{IR}_{i,t,k} = \frac{1}{N^j_{i,t,k}} \sum_{i,t,k} IR_{k,t}$

23. Price of Idiosyncratic Risk$_{i,t}$ $= \frac{DR_{i,t,High} - DR_{i,t,Low}}{\text{Average IR}_{i,t,High} - \text{Average IR}_{i,t,Low}}$, where High and Low corresponds to the two firm-year portfolios sorted on the exposure to idiosyncratic risk.
24. Largest Peers' Projects' Idiosyncratic Shock: Max Peer IR$_{p,t}$ $= max_{p,t}[\zeta_{-j}]$
25. Average Largest Peers' Projects' Idiosyncratic Shock: Average Max PIR$_{i,t,k}$ $= \frac{1}{N^j_{i,t,k}} \sum_{i,t,k}$ Max Peer IR$_{p,t}$
26. Firm Diversification$_{i,t}$ $= \frac{N^j_{i,t} - 1}{\sum_{i,t}(\zeta_j - \bar{\zeta}_{i,t})^2}$

Appendix A.2. Financial Market Variables

For the regressions using Compustat variables or other financial market variables, the variable definitions are below. Names are denoted by their Xpressfeed pneumonic in bold, when available.

1. Total Book Assets = **at**
2. Total debt = **dltt** + **dlc**
3. Book Leverage $= \frac{\text{Total Debt}}{\text{Total Book Assets}}$
4. Market Value of Equity: MVE$_{i,t}$ = **pstk** + **csho*prcc_c**
5. β^{OG}_t = One year CAMP Oil and Gas Industry beta, computed at the monthly frequency.
6. Risk-free rate: rf_t = 10-year risk-free rate from St-Louis Federal Reserve.
7. Industry Cost of Equity: $\text{r}^E_t = \beta^{OG}_t * \frac{E_t}{P_t}$
8. Cost of Debt: $\text{r}^D_{i,t}$ = Interest rate of trading bonds from firms of equivalent credit rating.
9. Weighted Average Cost of Capital: WACC$_{i,t}$ $= \frac{\text{MVE}_{i,t}}{\text{MVE}_{i,t} + \text{Total Debt}_{i,t}} * (\text{r}^E_t + rf_t) + \frac{\text{Total Debt}_{i,t}}{\text{MVE}_{i,t} + \text{Total Debt}_{i,t}} * r^D_{i,t}$
10. Cash Flow: CF $= \frac{\textbf{oancf} + \textbf{intpn}}{\textbf{at}}$
11. TLTD $= \frac{\textbf{dltt} + \textbf{dlc}}{\textbf{at}}$
12. TDIV $= \frac{\textbf{dvp} + \textbf{dvc}}{\textbf{at}}$
13. CASH $= \frac{\textbf{che}}{\textbf{at}}$
14. Market-to-book ratio: Q $= \frac{\text{MVE} + \text{Total Debt} - \textbf{txditc}}{\textbf{at}}$
15. DIVPOS = is indicator that equals one if the firm pays dividends, and zero otherwise
16. LNTA $= ln(\textbf{at})$
17. Three-digit industry YoY sales growth: ISG $= \frac{\sum_{3\ digit\ SIC} \textbf{sale}_{i,t+1}}{\sum_{3\ digit\ SIC} \textbf{sale}_{i,t}}$
18. Own-firm real Year-over-Year (YoY) sales growth: SG $= \frac{\text{Real } \textbf{sale}_{i,t+1}}{\text{Real } \textbf{sale}_{i,t}}$
19. CURAT $= \frac{\textbf{act}}{\textbf{lct}}$
20. COVER $= \frac{\textbf{oibdp} - \textbf{dp}}{(\textbf{xint} + \textbf{dvp})/(1 - \tau\_c)}$, where τ_c is the tax rate.
21. IMARG $= \frac{\textbf{ni}}{\textbf{sale}}$
22. SLACK $= \frac{\textbf{che} + 0.5 * \textbf{invt} + 0.7 * \textbf{rect} - \textbf{dlc}}{\textbf{ppent}}$

Appendix A.3. Costly external financial variables

In the paper, I use three indexes to proxy for the level of costly external financing by firms. To construct each three of the proxies (Cleary Index, Whited-Wu Index, and Kaplan-Zingales index), I process the data following the methodology presented in Hennessy and Whited (2007). For each index to have the same interpretation, I follow the recommendation of Hennessy and Whited (2007) and multiply the Cleary index by -1, such that it is increasing in the likelihood of facing costly external finance.

The indexes are constructed in the following way:

$$\begin{aligned}
\textit{Kaplan-Zingales index} &= -1.001909CF + 3.139193TLTD - 39.36780TDIV \\
&\quad - 1.314759CASH + 0.2826389Q \\
\textit{Whited-Wu index} &= -0.091CF - 0.062DIVPOS + 0.021TLTD - 0.044LNTA \\
&\quad + 0.102ISG - 0.035SG \\
\textit{Cleary index} &= -0.11905CURAT - 1.903670TLTD + 0.00138COVER \\
&\quad + 1.45618IMARG + 2.03604SG - 0.04772SLACK
\end{aligned}$$

Appendix B. Linearized ARP model

To estimate the Arp model using a OLS regression, I linearize the equation such that:

$$\begin{aligned}
q_{j,m} &= A_j(1 + b\theta m)^{\frac{-1}{b}} \\
ln(q_{j,m}) &= ln(A_j) - \frac{1}{b}ln(1 + b\theta m) \\
ln(q_{j,m}) &= \alpha_1 + \alpha_2 + A_j + \sum_{k=1}^{K} \beta_k m^k
\end{aligned}$$

Where the last step is obtained by doing a Taylor expansion of the term $ln(1 + b\theta m)$. For a fixed m sufficiently small, the expansion terms converge to zero, since the product of b and θ is close to zero. In other words, I can approximate the hyperbolic decline curve using a Kth order polynomial. Finally, I include two dummy variables, α_1 and α_2, respectively equal to 1 for the first and second month of the well's production and zero otherwise, to account for the wells production ramp-up patterns (Dennis, 2017).

Appendix C. Revealed Preference Strategy with Real Option

To account for the real option effect, I adjust the firms' decision rule, such that it is no longer optimal to investment when the expected discounted cash flow of the are greater than the well's cost (C_j), but when they are greater than the real option optimal threshold (V_j^*) such that:

$$\sum_{m=1}^{M} \frac{1}{(1+\mu_j)^m} \mathbb{E}[q_{j,m} P_m] - V_j^* = 0$$

To compute the real option optimal threshold (V_j^*), I follow the methodology introduced in Dixit and Pindyck (1996, Chapter 5) such that:

$$V_j^* = \frac{\beta_j^1}{\beta_j^1 - 1} * C_j$$
$$\beta_j^1 = \frac{1}{2} - \frac{r_t - \delta_t}{\sigma_j^2} + \sqrt{[\frac{(r_t - \delta_t)}{\sigma_j^2} - \frac{1}{2}]^2 + \frac{2r_t}{\sigma_j^2}}$$

where C_j denotes the well's drilling cost, r denotes the 10-year risk-free rate, δ_t corresponds to the project's dividend rate, and σ^2 is the project's risks.

I follow Brennan and Schwartz (1985) and set the dividend rate (i.e., δ_t) equal to the natural gas convenience yield. I compute the convenience yield using the natural gas spot and Bloomberg Natural Gas Future prices. Precisely, I obtain the natural gas convenience yield (i.e., δ_t) such that:

$$\delta_t = r + \frac{1}{T}(1 - \frac{F}{S})$$

Where F is the Bloomberg Natural Gas Future Price, and S is the spot price.

Finally, I define the project's risks as the combination of the project's idiosyncratic risk and price risk. The project's idiosyncratic risk is the same measure used throughout the paper. The measure of price risk corresponds to the 36 months Bloomberg Natural Gas Futures contract implied volatility. Kellogg (2014) has an extensive discussion on which measure of price uncertainty is best to use in a real option calibration, and concludes that using implied volatility derived from financial derivative provides the best performance. However, the financial option for the 36 months horizon contracts are not available on Bloomberg before 2000. For this reason, the number of observation used in the regression of this section is less that the one for the main specification.

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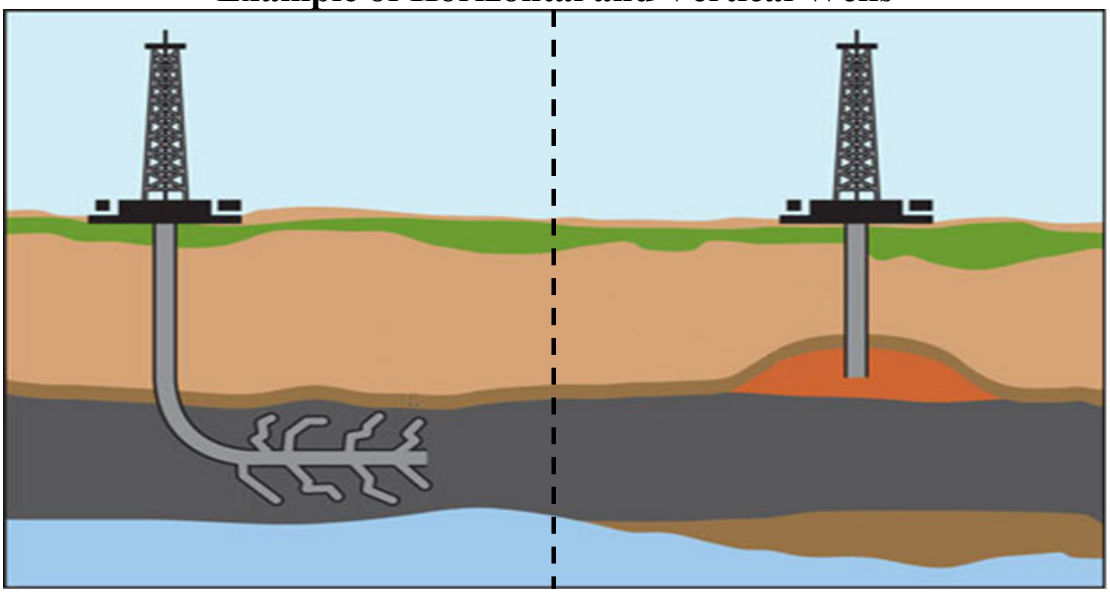
Example of Horizontal and Vertical Wells



(1) Horizontal Well (2) Vertical Well

Figure 1: Vertical versus Horizontal Drilling Technology

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). During the analyzed period, 89% of the gas well drilled where completed using the vertical technology.

Panhandle Field's Development from 1961 to 2010

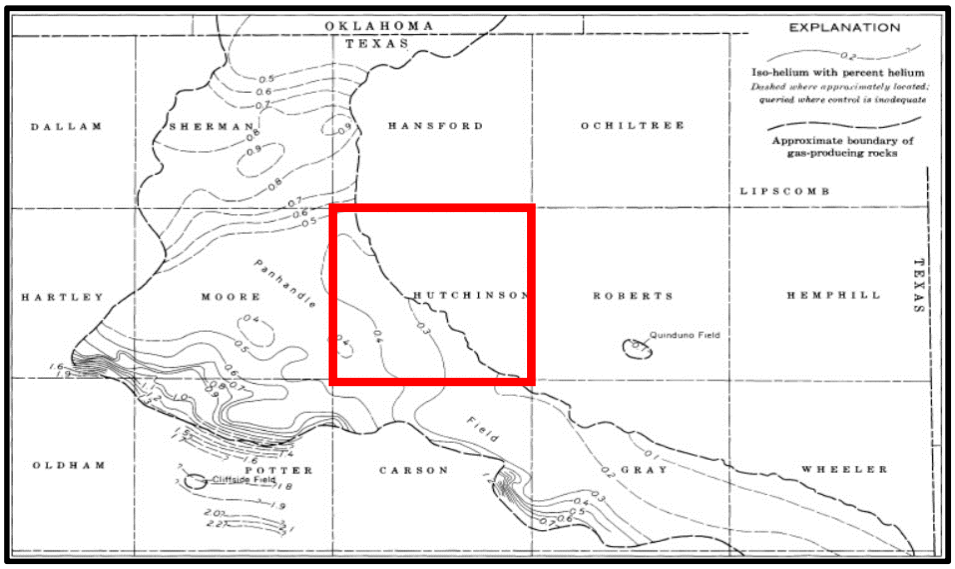


Figure 2.1. 1961 map of approximate boundary of Panhandle oil and gas field producing region. Source: *Anderson and Hinson, 1961; Boone 1958; and G.B. Shelton, U.S. Bureau of Mines, written communication, 1958* .

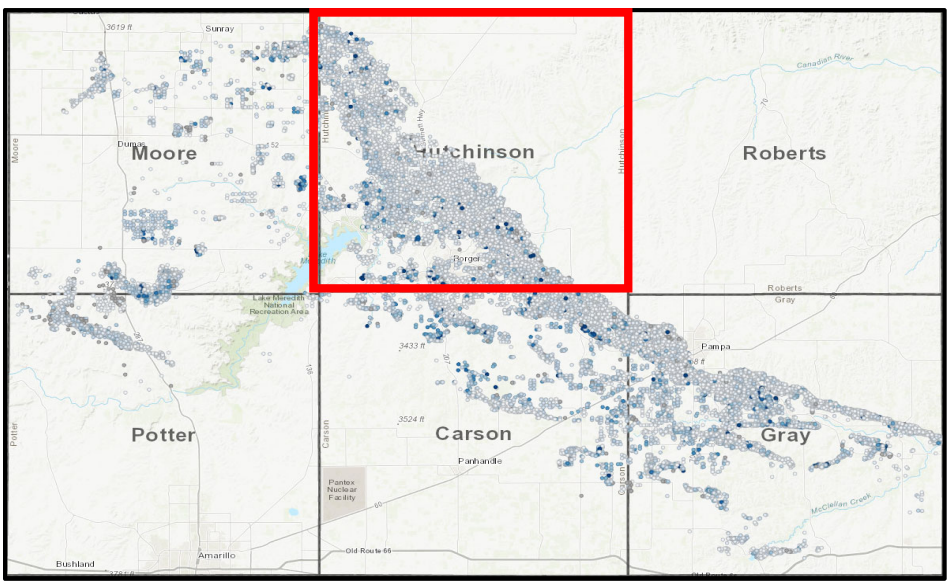


Figure 2.2. 2010 map of cumulative oil and gas wells drilled in the Panhandle field. Each white dot represents an individual well. Wells' quality is indicated by a color code. Darker shade of blue indicates wells that were among the most productive of the region, while dots color coded in gray indicate lower level of productivity.

Figure 2. Panhandle Field (Texas) Development Progress between 1961-2010

This panel of figures plots the evolution of the Panhandle field development over the period 1961 to 2010. Figure 2.1. provides the initial expectation of the field boundary, based on geological surveys. Figure 2.2. provides an updated view of the field development. The red square indicates the Hutchinson county to help align the surveyor map with the 2010 map.

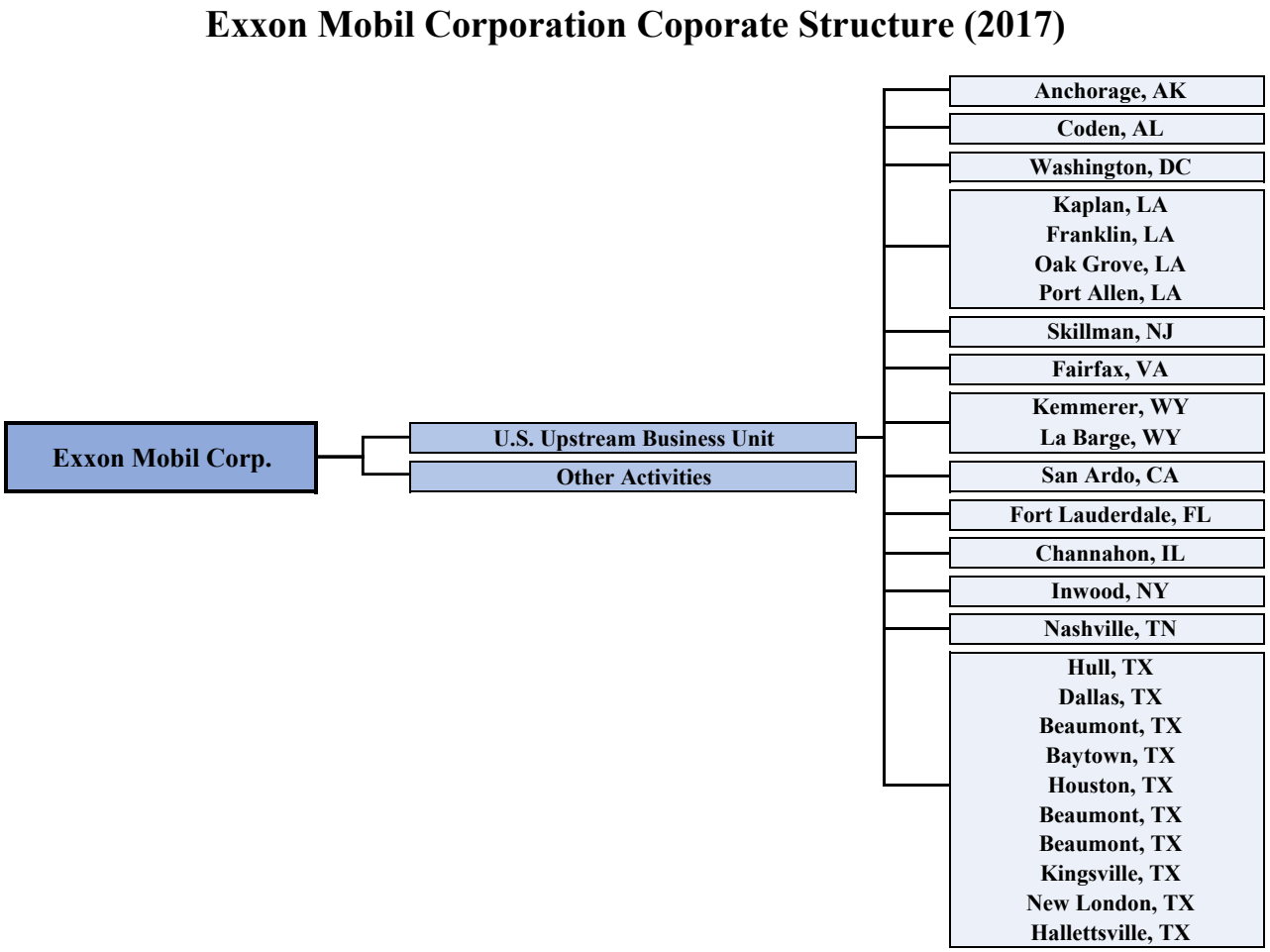


Figure 3: Corporate Structure of the U.S. Upstream Business of Exxon Mobil Corporation (2017).
This figure presents a representative example of the corporate tree structure for a firm with upstream activities across multiple regions of the Unites States. As for most firms with upstream activity, the business unit are organized into geographic region. Source: Lexis Nexis Academic Edition.

Geographic Distribution of the Vertical Gas Wells

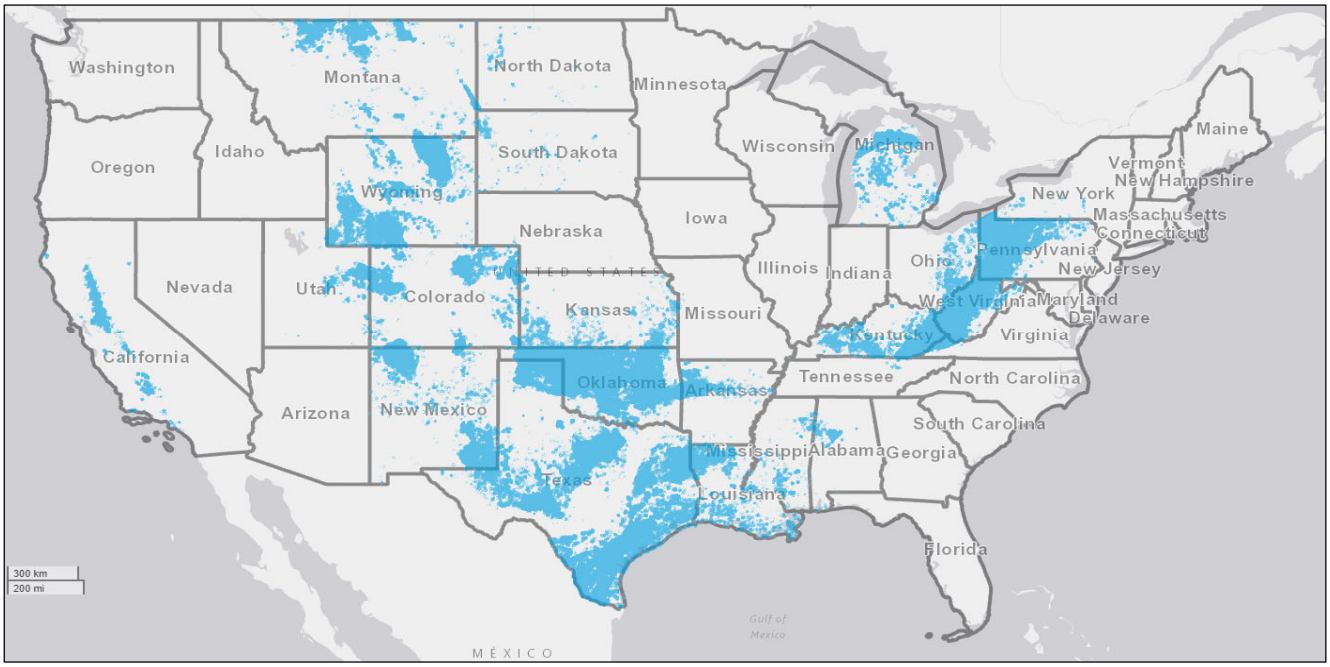


Figure 4: Projects Geographic Distribution
This figure plots the sample of wells included in the analysis. The total sample includes 114,696 vertical gas wells drilled over the period ranging from 1983 to 2010. The map provides information on the regions with the most activity during the analyzed period.

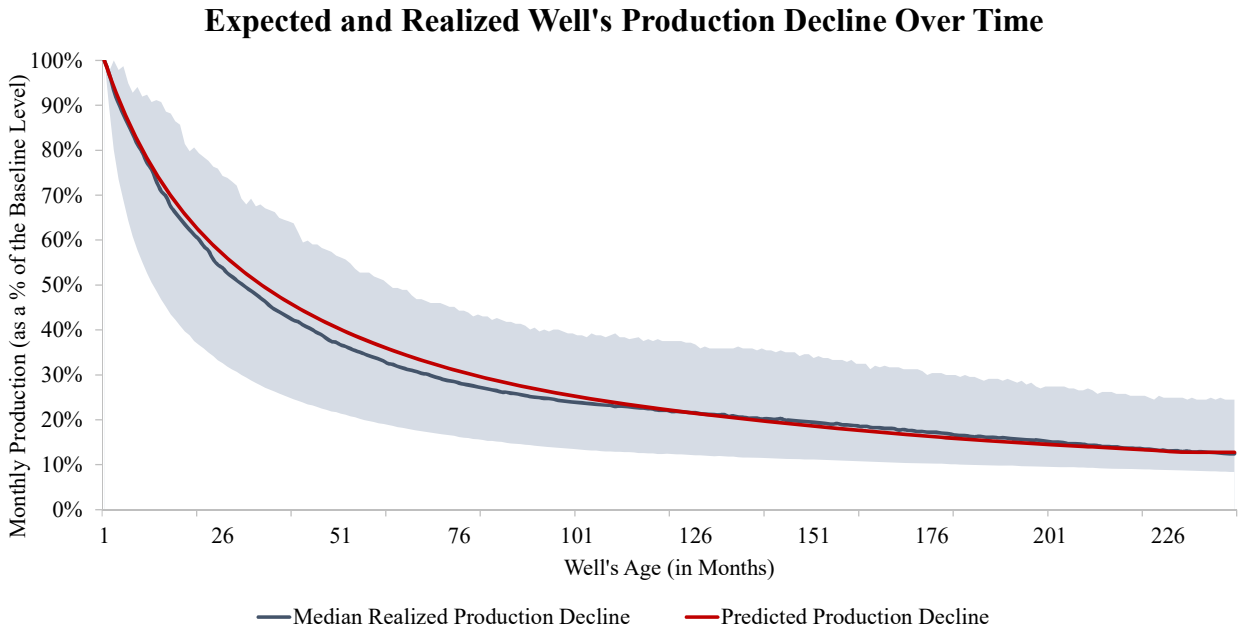
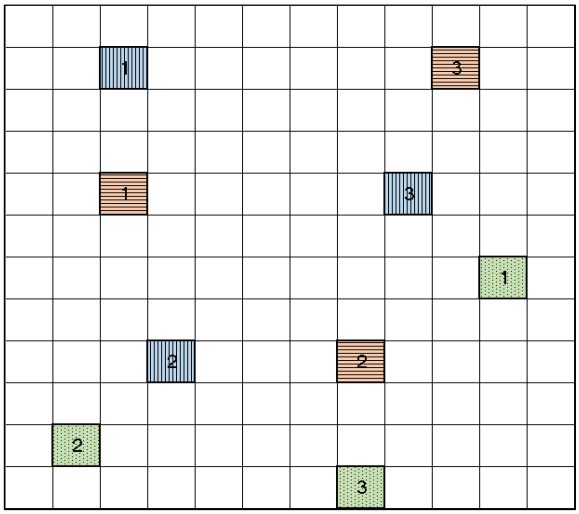


Figure 5: Arp Hyperbolic Production Curve

This figure plots the wells production decline level over time. The blue line corresponds to the median empirical production, the red line corresponds to the hyperbolic Arp prediction and the shaded area represent the 10th and 90th confidence interval.

Example of the Instrumental Variable Strategy



Idiosyncratic Profitability Shocks (ξ_j)			
	Horizontal Orange	Vertical Blue	Dotted Green
Well 1	0.05	-0.22	0.23
Well 2	-0.1	0.1	0.03
Well 3	0.12	0.01	-0.04
Largest Peer's Idiosyncratic Profitability	0.23	0.23	0.12

Projects' Idiosyncratic Risk	0.131

Figure 6.1. Bird Eye View of a Township-Year

Figure 6: Example of the Instrumental Variable Strategy

Figure 6.1. presents a simplified example of wells being drilled in a given township-year. In this example, three firms (i.e., dotted green, horizontal orange, and vertical blue) were active in the township during that specific year. The adjacent table reports an illustrative example of the potential idiosyncratic productivity shock, measured for each of the wells. The instrumental variable used in the paper, The variable *Largest Peers' Idiosyncratic Profitability Shock,* corresponds to the biggest shock that was measure for the firm's peers in its wells' township-year, averaged at the firm-year porfolios level. The variable *Projects' Idiosyncratic Risk* is the cross-section dispersion of the idiosyncratic profitability shock computed for the township-year. To obtain the Projects' Average Idiosyncratic Risk, I take the average value for each firm-year porfolio.

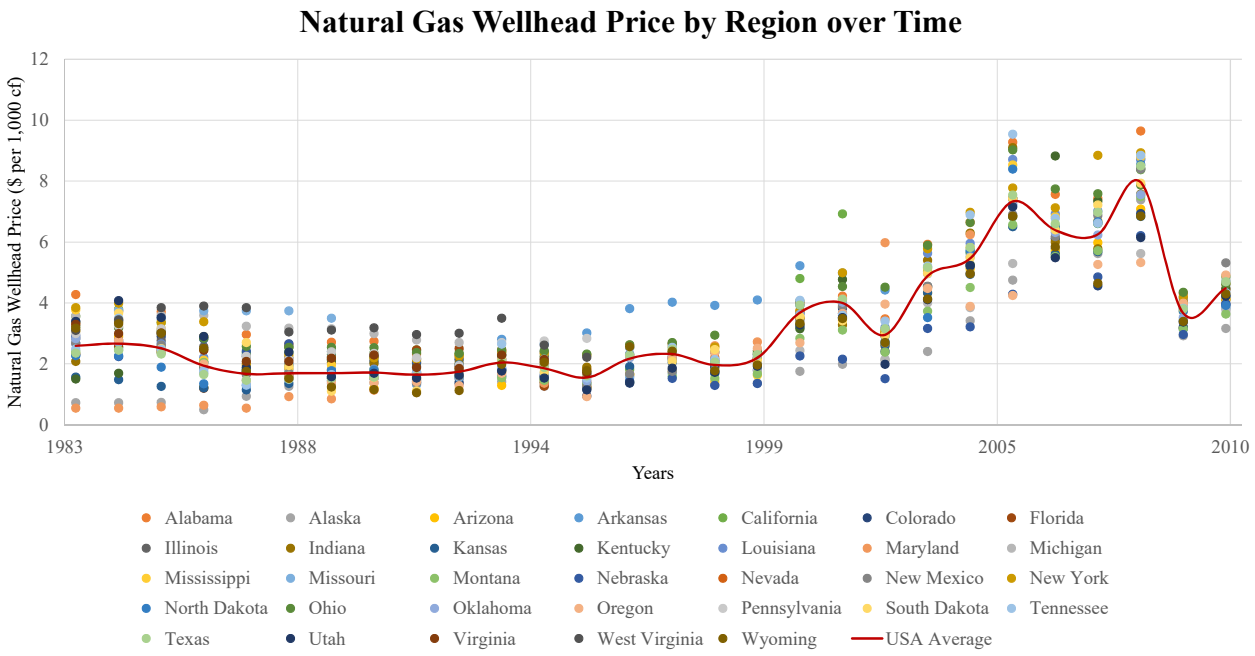


Figure 7: Natural Gas Wellhead Price by States between 1983 and 2010
This figure plots the evolution of yearly natural gas wellhead prices for each producing state over time. Source: *https://www.eia.gov/dnav/ng/ng_prod_whv_a_EPG0_FWA_dpmcf_a.htm*

Table I
Summary Statistics of Firms' and Wells' Characteristics

This table reports summary statistics of exploration and production gas companies included in the sample. The time period of the sample is from 1983 to 2010. The sample consist of all firms drilling at least 10 gas wells in the year of analysis, and wells drilled in township-year with at least 3 wells. I exclude from the analysis all wells with missing fields, and wells for which the first production date occurs before the drilling date, as they correspond to data entry error. Panel A reports summary statistics of the firm's characteristics. Panel B reports well-level characteristics used to estimate the Arp model.

	Observation	Mean	Median	Std. Dev.
Panel A: Firm Level Data				
Assets (In millions $)	3,946	229.17	84.87	383.79
Annual Budget (In millions $)	3,946	60.34	22.95	108.80
Annual Budget per Field (In millions $)	3,946	11.30	6.07	17.57
Annual Budget per State (In millions $)	3,946	19.37	10.30	30.09
Number of Firms	369			
	Observation	Mean	Median	Std. Dev.
Panel B: Well Level Data				
Drilling Cost ($)	114,696	465,652.90	402,357.30	299,580.20
Drilling Cost ($ per foot)	114,696	79.07	81.48	6.94
Royalty Rate (%)	114,696	17.32%	18.75%	2.83%
Operational Cost (%)	114,696	20.00%	20.00%	0.00%
Well Total Gas Production (in 1,000 cf)	114,696	570,049.90	177,654.50	1,608,979.00
EIA three-year forecast gas prices (Per 1,000 cf)	114,696	4.05	3.37	1.83

Table II
Arp Model Estimation

This table reports coefficient estimates from an OLS regression, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010.The unit of observation in the underlying table is at the well j and well's age (in month) m level. Subscript p denotes specific township, and subscript t indicates the year well j was drilled. The Age variable corresponds to the well age (in month) m raise to the power of the superscript. For example, Age^2 denotes the well's age in month raised to the power of 2. The variable $Depth_i$ denotes the natural logarithm of the well's total vertical depth in foot. The variable $Local\ Information_j$ corresponds to the natural log of the number of wells drilled in well j's township, at the moment of drilling. The variable $Firm's\ Local\ Experience_j$ denotes the natural log of the firm's total number of wells drilled by firm i in well j's township, at the moment of drilling well j. $Firm\ Total\ Experience_j$ represent the natural log of the total number of wells drilled by firm i, at the time of drilling well j. The precision of those coefficient is important to properly match the realized production data. For this reason, I allow for 21 digits. See appendix B for a complete description of the model derivation. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Ln(Gas Well Monthly Production$_{j,m}$)
	(1)
(β_1) Age^1	-0.046123952293677099312230***
	[-205.33]
(β_2) Age^2	0.000802229619753800043784***
	[73.52]
(β_3) Age^3	-0.000011060405281200000582***
	[-46.35]
(β_4) Age^4	0.000000095973699714300002***
	[35.72]
(β_5) Age^5	-0.000000000484147915426000***
	[-29.96]
(β_6) Age^6	0.000000000001290652064010***
	[26.20]
(β_7) Age^7	-0.000000000000001402168849***
	[-23.46]
(β_8) Ramp$_1$	-0.508063974623592096158120***
	[-184.07]
(β_9) Ramp$_2$	0.032797358221284100832094***
	[12.40]
(β_{10}) Depth$_j$	0.260683920294977111709045***
	[189.55]
(β_{11}) Local Information$_j$	-0.004502789277263300089793***
	[-4.53]
(β_{12}) Firm Local Experience$_j$	0.038126923544065098592437***
	[31.90]
(β_{13}) Firm Total Experience$_j$	0.015990787856916301168386***
	[38.76]
Firm-Year Fixed Effect$_{i,t}$	Yes
Tonwship-Year Fixed Effect$_{p,t}$	Yes
R-Squared	0.6860
Observations	30,420,544

Table III
Projects' Idiosyncratic Risk and Probability of Dry Hole

This table reports the *incidence rate ratio* estimates of a Poisson regression, and t-statistics robust to heteroskedasticity and within-township dependence in bracket. The unit of observation is at the township *p,* and year *t* level. The dependent variable, *Number of Dry Hole*, is a count variable that corresponds to the number of dry wells drilled in a given township-year. For example, a value of *2* indicates that there were 2 dry holes drilled in the township during that given year. *Project's Idiosyncratic Risk*$_{p,t}$ denotes the cross-sectional dispersion of the well's *Idiosyncratic Profitability Shock*, computed at the township *p* and year *t* level. The variable Project's Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Number of Dry Holes$_{p,t}$			
	(1)	(2)	(3)	(4)
(β_1) Project's Idiosyncratic Risk$_{p,t}$	1.246***	1.197***	1.246***	1.378***
	[5.14]	[3.55]	[2.62]	[2.90]
Year Fixed Effect$_t$	No	Yes	Yes	Yes
Township Fixed Effect$_p$	No	No	No	Yes
Pseudo R-Squared	0.005	0.070	0.243	0.273
Observations	12,386	12,386	12,386	12,386

Table IV
Firms' Discount Rate and The Cost of Capital

This table reports coefficient estimates from an OLS regression for relation between the cost of capital and firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* , and year *t* level. The Industry Cost of Equity is calculated using the oil and gas industry beta, computed at the monthly frequency on a one-year horizon basis, multiplied by the market excess return. The oil and gas industry returns are obtained from Kenneth French web site. Market excess return is approximated using the earning-to-price ratio obtained from Robert Shiller web site. The risk-free rate is the 10-year risk-free rate, obtained from the St-Louis Federal Reserve website. Finally, to compute the weighted average cost of capital (WACC), I obtain the cost of debt using firms credit rating reported in Capital IQ. See appendix A.2 for the full methodological details. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$				(Discount Rate - Risk Free Rate) $(\%)_{i,t,k}$			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Industry Cost of Equity $(\%)_t$					1.950***	1.164***	1.497***	0.973***
					[8.07]	[6.93]	[8.17]	[5.71]
(β_2) WACC $(\%)_{i,t}$	1.136**	1.274**	1.221***	1.186**				
	[2.12]	[2.23]	[2.69]	[2.20]				
(β_3) Project's Average Idiosyncratic $Risk_{i,t,k}$			11.928***	10.110**			9.950***	5.303***
			[3.08]	[2.47]			[8.06]	[6.08]
Firm Fixed $Effect_i$	No	Yes	No	Yes	No	Yes	No	Yes
R-Squared	0.006	0.293	0.148	0.380	0.048	0.651	0.234	0.680
F-Statistics	4.493	4.958	16.429	12.290	65.113	47.971	57.475	45.556
Observations	747	747	747	747	3,946	3,946	3,946	3,946

Table V
Managers' Project-Level Idiosyncratic Risk Pricing

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t and portfolio k level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	12.677***	8.610***	7.891***	7.884***	7.876***	7.876***	7.901***
	[5.93]	[3.32]	[2.87]	[2.88]	[2.88]	[2.88]	[2.91]
(β_2) Budget$_{i,t}$				0.005		0.003	
				[0.57]		[0.31]	
(β_3) Assets$_{i,t}$					0.004	0.003	
					[0.98]	[0.94]	
Firm Fixed Effect$_i$	No	Yes	Yes	Yes	Yes	Yes	No
Year Fixed Effect$_t$	No	No	Yes	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	No	No	No	Yes
R-Squared	0.146	0.438	0.455	0.455	0.455	0.455	0.730
F-Statistics	35.161	10.992	8.230	9.802	5.236	7.329	8.465
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table VI

Instrumented Regression - Managers' Project-Level Idiosyncratic Risk Pricing

This table reports the effects of project-level idiosyncratic risk on firms' discount rate based on the exogenous measure of Projects' Average Idiosyncratic Risk from an instrument, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* , year *t,* and portfolio *k* level. The results in Panel A report the first stage coefficient estimates of a two stage OLS regression which uses the average of the firm's peers' largest idiosyncratic productivity shocks of each wells, to instrument for the variable Projects' Average Idiosyncratic Risk. The bottom of Panel A reports the first stage F-statistic on the instrument for the two-stage least-square regression. Panel B reports the second stage regression results of the instrumented model. *Projects' Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

Panel A: First Stage	Projects' Average Idiosyncratic Risk$_{i,t,k}$						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
(β_1) Average Largest Peers' Projects' Idiosyncractic Shock$_{i,t,k}$	0.7886***	0.7059***	0.7321***	0.7320***	0.7319***	0.7319***	0.8382***
	[12.10]	[12.21]	[11.90]	[11.89]	[11.89]	[11.89]	[14.38]
(β_2) Budget$_{i,t}$				0.0001		0.0001	
				[0.70]		[0.25]	
(β_3) Assets$_{i,t}$					0.0001	0.0001	
					[0.76]	[0.44]	
Firm Fixed Effect$_i$	No	Yes	Yes	Yes	Yes	Yes	No
Year Fixed Effect$_t$	No	No	Yes	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	No	No	No	Yes
R-Squared	0.622	0.749	0.786	0.786	0.786	0.786	0.897
Kleibergen-Paap First Stage F-Statistics	146.4509	149.1750	141.6812	70.7336	70.8062	47.1647	206.7006

Panel B: Instrumented Regression	Discount Rate (%)$_{i,t,k}$						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	10.454***	5.234***	5.769***	5.764***	5.752***	5.753***	6.653***
	[7.35]	[3.72]	[4.14]	[4.13]	[4.12]	[4.12]	[5.23]
(β_2) Budget$_{i,t}$				0.006		0.003	
				[0.58]		[0.31]	
(β_3) Assets$_{i,t}$					0.004	0.003	
					[0.98]	[1.13]	
Firm Fixed Effect$_i$	No	Yes	Yes	Yes	Yes	Yes	No
Year Fixed Effect$_t$	No	No	Yes	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	No	No	No	Yes
R-Squared	0.141	0.432	0.453	0.453	0.453	0.453	0.730
F-Statistics	54.028	13.806	17.160	9.067	9.325	6.249	27.359
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table VII
Firms' Performance and Managers' Idiosyncratic Risk Pricing

This table reports coefficient estimates from an OLS regression for the effect of the price of idiosyncratic risk on firms' performance, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* and year *t* level. The variable *Price of Idiosyncratic Risk* corresponds to the firm's price of idiosyncratic risk computed at a yearly frequency. The dependent variables correspond to the firm gross profit margin (%), the gross profitability (%), the YoY asset growth (%), and the investment rate (%), and are winsorized at the 1 and 99 percentiles. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. Detailed calculation of the four dependent variables is available in appendix A.1. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Gross Profit Margin $(\%)_{i,t}$		Gross Profitability $(\%)_{i,t}$		YoY Asset Growth $(\%)_{i,t+1}$		Investment Rate $(\%)_{i,t+1}$	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Price of Idiosyncratic $Risk_{i,t}$	-5.053**	-5.110**	-0.511**	-0.501**	-0.745*	-0.747*	-0.811*	-0.814*
	[-2.47]	[-2.54]	[-2.04]	[-1.98]	[-1.71]	[-1.71]	[-1.67]	[-1.67]
(β_2) $Budget_{i,t}$		-0.020		-0.055*		0.017		0.024
		[-0.26]		[-1.76]		[1.25]		[1.36]
(β_3) $Assets_{i,t}$		-0.092***		0.008		-0.000		-0.002
		[-3.02]		[0.62]		[-0.05]		[-0.30]
Firm Fixed $Effect_i$	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Year Fixed $Effect_t$	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
R-Squared	0.530	0.539	0.808	0.809	0.414	0.415	0.431	0.432
F-Statistics	6.097	8.397	4.144	3.259	2.935	2.447	2.801	2.297
Observations	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973

Table VIII
Managers' Project-Level Idiosyncratic Risk Pricing and Firms' Size

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i*, year *t*, and portfolio *k* level. Project's Idiosyncratic Risk denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The instrumented regression contains up to three instrumented variables, the *Projects' Average Idiosyncratic Risk,* the *Projects' Average Idiosyncratic Risk * Assets*, and for some specifications the *Projects' Average Idiosyncratic Risk * Diversification*. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. Detailed calculation of each variable is available in appendix A.1. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	9.641***	9.639***	10.493***	10.862***	7.077***	7.082***	7.623***	8.942***
	[2.77]	[2.78]	[2.73]	[2.69]	[4.07]	[4.08]	[4.03]	[5.31]
(β_2) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * $Assets_{i,t}$	-0.013**	-0.012**	-0.012**	-0.014**	-0.010**	-0.010**	-0.010**	-0.013***
	[-2.02]	[-2.02]	[-2.04]	[-2.22]	[-2.33]	[-2.34]	[-2.36]	[-3.44]
(β_3) $Assets_{i,t}$	0.014*	0.013**	0.013**		0.013***	0.012**	0.012**	
	[1.78]	[2.22]	[2.22]		[2.61]	[2.41]	[2.41]	
(β_4) $Budget_{i,t}$		0.002	0.002			0.002	0.002	
		[0.24]	[0.19]			[0.25]	[0.21]	
(β_5) Firm's $Diversification_{i,t}$			0.001				-0.003	
			[0.04]				[-0.18]	
(β_6) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * Firm's $Diversification_{i,t}$			-0.080*	-0.076			-0.052**	-0.043*
			[-1.71]	[-1.34]			[-2.06]	[-1.83]
Firm Fixed $Effect_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed $Effect_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.459	0.459	0.461	0.734	0.456	0.456	0.458	0.733
F-Statistics	3.528	5.147	3.464	3.393	7.157	5.392	3.794	11.748
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	52.733	52.919	32.939	70.792
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table IX
Managers' Project-Level Idiosyncratic Risk Pricing Private/Public Firms

This table reports coefficient estimates from an OLS regression and a 2SLS regression for the effect of firms' average projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* , year *t* , and portfolio *k* level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable *Private Dummy* is equal to 1 if the firm is private and 0 otherwise. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Dummy* . The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	12.693***	12.643***	12.572***	11.705**	9.286***	9.043***	9.045***	8.290***
	[3.08]	[3.08]	[3.11]	[2.24]	[5.39]	[5.30]	[5.33]	[5.01]
(β_3) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * Private $Dummy_i$	-0.606	-0.493	-0.443	-7.614	2.666	2.995	2.938	-3.250
	[-0.13]	[-0.11]	[-0.10]	[-1.42]	[0.94]	[1.06]	[1.04]	[-1.36]
(β_3) Private $Dummy_i$	1.087	0.255	0.703		-1.543	-2.552	-1.928	
	[0.42]	[0.10]	[0.24]		[-0.63]	[-1.02]	[-0.85]	
(β_4) $Assets_{i,t}$		-0.012***	-0.016**			-0.012***	-0.017**	
		[-3.12]	[-2.54]			[-3.14]	[-2.38]	
(β_5) $Budget_{i,t}$			0.010				0.012	
			[0.87]				[0.91]	
Year Fixed $Effect_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.159	0.163	0.164	0.734	0.155	0.159	0.160	0.733
F-Statistics	11.471	9.131	7.862	7.661	19.596	15.493	12.441	16.806
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	40.794	40.999	41.58	66.803
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table X
Managers' Project-Level Idiosyncratic Risk Pricing and Cleary Index

This table reports coefficient estimates from an OLS regression and a 2SLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t, and portfolio k level. Projects' Average Idiosyncratic Risk denotes the projects' average idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The *Cleary Index* is used as a costly external financing proxy. Its calculation details are available in appendix A.3. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Cleary Index*. The analysis is restricted to the set of firms available in Compustat for which the necessary variables for each indexes was available. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	14.463**	14.487**	14.494**	14.085**	15.730**	15.697**	15.719**	15.869**
	[2.28]	[2.28]	[2.28]	[2.26]	[2.36]	[2.35]	[2.36]	[2.38]
(β_2) Projects' Average Idiosyncratic Risk$_{i,t,k}$ * Cleary Index$_{i,t}$	0.036*	0.037*	0.037*	0.048	0.048	0.048	0.049	0.061
	[1.73]	[1.75]	[1.77]	[1.18]	[1.46]	[1.46]	[1.48]	[1.10]
(β_3) Cleary Index$_{i,t}$	-0.042*	-0.042*	-0.042*		-0.052	-0.052	-0.052	
	[-1.78]	[-1.79]	[-1.78]		[-1.56]	[-1.56]	[-1.56]	
(β_4) Assets$_{i,t}$		0.009	0.009			0.009	0.009	
		[1.10]	[1.13]			[1.12]	[1.16]	
(β_5) Budget$_{i,t}$		-0.010	-0.009			-0.010	-0.009	
		[-1.23]	[-1.30]			[-1.24]	[-1.29]	
(β_6) Leverage$_{i,t}$			-5.931				-6.133	
			[-0.47]				[-0.48]	
Firm Fixed Effect$_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed Effect$_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.383	0.383	0.383	0.653	0.382	0.383	0.383	0.653
F-Statistics	1.882	2.270	1.949	3.090	1.909	2.126	1.856	4.071
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	23.021	23.064	22.93	34.273
Observations	792	792	792	792	792	792	792	792

Table XI
Managers' Project-Level Idiosyncratic Risk Pricing and Whited-Wu Index

This table reports coefficient estimates from an OLS regression and a 2SLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t, and portfolio k level. *Projects' Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The Whited-Wu Index is used as a costly external financing proxy. Its calculation detail is available in appendix A.3. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Whited-Wu Index*. The analysis is restricted to the set of firms available in Compustat for which the necessary variables for each indexes was available. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	12.983**	12.991**	12.990**	12.174**	13.645**	13.613**	13.614**	13.251***
	[2.13]	[2.12]	[2.12]	[2.37]	[2.37]	[2.36]	[2.35]	[2.72]
(β_2) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * WW $Index_{i,t}$	1.405	1.403	1.399	1.255	0.521	0.515	0.516	0.710
	[1.04]	[1.04]	[1.03]	[1.06]	[0.39]	[0.38]	[0.38]	[0.43]
(β_3) WW $Index_{i,t}$	-1.571	-1.548	-1.541		-0.881	-0.854	-0.850	
	[-1.45]	[-1.43]	[-1.42]		[-0.82]	[-0.79]	[-0.79]	
(β_4) $Assets_{i,t}$		0.008	0.007			0.008	0.008	
		[0.94]	[0.96]			[0.99]	[1.03]	
(β_5) $Budget_{i,t}$		-0.009	-0.009			-0.009	-0.008	
		[-1.16]	[-1.22]			[-1.16]	[-1.21]	
(β_6) $Leverage_{i,t}$			-4.949				-5.296	
			[-0.39]				[-0.42]	
Firm Fixed $Effect_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed $Effect_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.383	0.384	0.384	0.652	0.382	0.382	0.382	0.652
F-Statistics	2.519	2.730	2.487	2.998	2.283	2.405	2.140	3.720
Kleibergen-Paap First-Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	19.27	19.387	19.369	54.097
Observations	792	792	792	792	792	792	792	792

Table XII
Managers' Project-Level Idiosyncratic Risk Pricing and Kaplan-Zingales Index

This table reports coefficient estimates from an OLS regression and a 2SLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t and portfolio k level. *Projects' Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The Kaplan-Zingales Index is used as a costly external financing proxy. Its calculation details are available in appendix A.3. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Kaplan-Zingales Index*. The analysis is restricted to the set of firms available in Compustat for which the necessary variables for each indexes was available. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	13.304*	13.334*	13.346*	12.642**	14.453*	14.412*	14.433*	14.622**
	[1.95]	[1.95]	[1.94]	[2.05]	[1.92]	[1.91]	[1.91]	[2.04]
(β_2) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * KZ $Index_{i,t}$	-0.300	-0.338	-0.356	-1.139	-1.367	-1.370	-1.394	-2.378
	[-0.09]	[-0.10]	[-0.11]	[-0.34]	[-0.34]	[-0.34]	[-0.35]	[-0.53]
(β_3) KZ $Index_{i,t}$	0.391	0.459	1.230		1.202	1.255	2.072	
	[0.11]	[0.13]	[0.36]		[0.29]	[0.30]	[0.53]	
(β_4) $Assets_{i,t}$		0.011	0.011			0.012	0.012	
		[1.51]	[1.54]			[1.53]	[1.56]	
(β_5) $Budget_{i,t}$		-0.013	-0.012			-0.013	-0.012	
		[-1.52]	[-1.62]			[-1.51]	[-1.59]	
(β_6) $Leverage_{i,t}$			-7.992				-8.421	
			[-0.53]				[-0.56]	
Firm Fixed $Effect_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed $Effect_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.375	0.376	0.376	0.645	0.375	0.375	0.376	0.644
F-Statistics	2.172	2.458	2.237	4.263	2.521	2.577	2.339	5.399
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	7.219	7.255	7.225	12.939
Observations	792	792	792	792	792	792	792	792

Table XIII

Managers' Project-Level Idiosyncratic Risk Pricing and Managers' Budget - Fields

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t, and portfolio k level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable *Managers' Average Budget* corresponds to the managers budget size averaged at the firm-year level, when assuming that managers are assigned to distinct fields. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Managers' Average Budget*. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. Detailed calculation of the regression variables is available in appendix A.1. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	9.135***	9.132***	9.120***	9.123***	6.730***	6.701***	6.709***	8.303***
	[2.70]	[2.70]	[2.71]	[2.70]	[3.93]	[3.90]	[3.91]	[5.32]
(β_2) Projects' Average Idiosyncratic Risk$_{i,t,k}$ * Managers' Average Budget$_{i,t}$	-0.087*	-0.086*	-0.086*	-0.086*	-0.056*	-0.054*	-0.054*	-0.102***
	[-1.80]	[-1.81]	[-1.80]	[-1.80]	[-1.80]	[-1.68]	[-1.68]	[-3.34]
(β_3) Assets$_{i,t}$			0.003	0.002			0.003	
			[0.70]	[0.62]			[0.30]	
(β_4) Budget$_{i,t}$		0.005		0.003		0.003	0.003	
		[0.44]		[0.31]		[0.73]	[0.80]	
(β_5) Managers' Average Budget$_{i,t}$	0.082	0.070*	0.071		0.062*	0.048	0.043	
	[1.62]	[1.76]	[1.53]		[1.83]	[1.18]	[0.90]	
Firm Fixed Effect$_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed Effect$_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.457	0.457	0.457	0.458	0.455	0.455	0.455	0.732
F-Statistics	4.233	5.862	3.392	5.217	7.072	5.414	4.375	15.744
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	73.467	73.400	73.354	116.905
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table XIV

Managers' Project-Level Idiosyncratic Risk Pricing and Managers' Budget - States

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t, and portfolio k level. Project's Average Idiosyncratic Risk denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable Managers' Average Budget corresponds to the managers budget size averaged at the firm-year level, when assuming that managers are assigned to distinct states. The instrumented regression contains two instrumented variables, the *Projects' Average Idiosyncratic Risk* and the *Projects' Average Idiosyncratic Risk * Managers' Average Budget*. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. Detailed calculation of the regression variables is available in appendix A.1. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$							
	Reduced Form Regression				Instrumented Regression			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	9.509***	9.523***	9.501***	9.514***	6.947***	6.910***	6.927***	8.237***
	[2.71]	[2.71]	[2.71]	[2.70]	[4.05]	[4.02]	[4.04]	[5.37]
(β_2) Projects' Average Idiosyncratic Risk$_{i,t,k}$ * Managers' Average Budget$_{i,t}$	-0.072**	-0.073**	-0.073**	-0.073**	-0.044**	-0.042**	-0.042**	-0.060***
	[-2.01]	[-1.99]	[-2.01]	[-1.98]	[-2.49]	[-2.32]	[-2.32]	[-3.38]
(β_3) Assets$_{i,t}$			0.005	0.004			0.006	
			[1.15]	[1.09]			[0.53]	
(β_4) Budget$_{i,t}$		0.009		0.007		0.005	0.004	
		[0.70]		[0.56]		[1.17]	[1.23]	
(β_5) Managers' Average Budget$_{i,t}$	0.051	0.035	0.037		0.034*	0.018	0.010	
	[1.54]	[1.49]	[1.27]		[1.95]	[0.87]	[0.35]	
Firm Fixed Effect$_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed Effect$_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.458	0.459	0.459	0.459	0.456	0.456	0.456	0.732
F-Statistics	5.243	5.747	3.712	5.414	8.076	6.205	5.007	15.941
Kleibergen-Paap First Stage F-Statistics	N.A.	N.A.	N.A.	N.A.	66.600	66.548	66.443	113.235
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table XV
Firms Characteristics and Projects' Risk

This table reports the effects of firm characteristics on the chosen projects' risk level, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation at the township p, and year t level. The dependent variable *Project's Idiosyncratic Risk* $_{p,t}$ denotes the cross-sectional dispersion of the well's *Idiosyncratic Profitability Shock*, computed at the township p and year t level (see appendix A.1. for the detailed calculation). *Managers' Average Budget* corresponds to the firm-year average manager's budget when managers are assumed to be assignment to specific fields in columns (1) and (2), or to specific states level in columns (3) and (4). The variable Manager's Average Budget is scaled by its standard deviation.* indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Project's Idiosyncratic $Risk_{p,t}$					
	State Assignment			Field Assignment		
	(1)	(2)	(3)	(4)	(5)	(6)
(β_1) Managers' Average $Budget_{i,t}$	0.439**	0.645*	0.700*	0.507***	0.669***	0.685***
	[2.35]	[1.96]	[1.74]	[3.55]	[3.21]	[3.36]
(β_2) $Assets_{i,t}$		-0.001	-0.001		-0.001	-0.002
		[-1.15]	[-1.07]		[-1.27]	[-1.18]
(β_3) $Budget_{i,t}$			-0.000			0.000
			[-0.13]			[0.16]
(β_4) Township-Year Average Well's $Cost_{p,t}$			-2.002			-2.062
			[-0.85]			[-0.87]
Firm Fixed $Effect_i$	Yes	Yes	Yes	Yes	Yes	Yes
Year Fixed $Effect_t$	Yes	Yes	Yes	Yes	Yes	Yes
Township Fixed $Effect_p$	Yes	Yes	Yes	Yes	Yes	Yes
R-Squared	0.474	0.475	0.475	0.475	0.475	0.475
F-Statistics	5.520	2.087	1.337	12.568	6.002	3.756
Observations	20,725	20,725	20,725	20,725	20,725	20,725

Table XVI

Managers' Project-Level Idiosyncratic Risk Pricing and Managers' Budget - Agency Effect

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i*, year *t*, and portfolio *k* level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). The variable *Managers' Average Budget* corresponds to the managers budget size averaged at the firm-year level. Column (1) to (4) reports the results when assuming that managers are assigned to specific fields, and columns (5) to (8) report to results when assuming that managers are assigned to different states. The variable *Distance* denotes the median distance between the firms' wells drilled during a given year in hundreds of miles, winsorised at the 5th and 95th percentile. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. Detailed calculation of the regression variables is available in appendix A.1. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$							
	Managers' Budget (Field Assignment)				Managers' Budget (State Assignment)			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	8.274***	8.276***	8.262***	8.274***	8.274***	8.276***	8.262***	8.274***
	[3.51]	[3.51]	[3.52]	[3.50]	[3.51]	[3.51]	[3.52]	[3.50]
(β_2) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * Managers' Average $Budget_{i,t}$	-0.063*	-0.062*	-0.062*	-0.061*	-0.063*	-0.062*	-0.062*	-0.061*
	[-1.65]	[-1.68]	[-1.65]	[-1.66]	[-1.65]	[-1.68]	[-1.65]	[-1.66]
(β_3) Projects' Average Idiosyncratic $Risk_{i,t,k}$ * Managers' Average $Budget_{i,t}$ * $Distance_{i,t}$	-0.075**	-0.077**	-0.075**	-0.077**	-0.075**	-0.077**	-0.075**	-0.077**
	[-2.22]	[-2.12]	[-2.21]	[-2.11]	[-2.22]	[-2.12]	[-2.21]	[-2.11]
(β_4) $Assets_{i,t}$			0.001	0.000			0.001	0.000
			[0.39]	[0.06]			[0.39]	[0.06]
(β_5) $Budget_{i,t}$		0.004		0.004		0.004		0.004
		[0.58]		[0.53]		[0.58]		[0.53]
(β_6) Managers' Average $Budget_{i,t}$	0.093*	0.082*	0.087*	0.082*	0.093*	0.082*	0.087*	0.082*
	[1.84]	[1.76]	[1.73]	[1.70]	[1.84]	[1.76]	[1.73]	[1.70]
(β_7) $Distance_{i,t}$	0.080	0.088	0.094	0.090	0.080	0.088	0.094	0.090
	[0.14]	[0.16]	[0.17]	[0.16]	[0.14]	[0.16]	[0.17]	[0.16]
(β_8) Managers' Average $Budget_{i,t}$ * $Distance_{i,t}$	0.039	0.037	0.038	0.037	0.039	0.037	0.038	0.037
	[0.76]	[0.74]	[0.75]	[0.74]	[0.76]	[0.74]	[0.75]	[0.74]
(β_9)Projects' Average Idiosyncratic $Risk_{i,t,k}$ * $Distance_{i,t}$	0.925	0.962	0.930	0.962	0.925	0.962	0.930	0.962
	[0.87]	[0.88]	[0.88]	[0.88]	[0.87]	[0.88]	[0.88]	[0.88]
Firm Fixed $Effect_i$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Year Fixed $Effect_t$	Yes	Yes	Yes	No	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes	No	No	No	Yes
R-Squared	0.615	0.615	0.615	0.615	0.615	0.615	0.615	0.615
F-Statistics	3.429	3.405	3.296	4.194	3.429	3.405	3.296	4.194
Observations	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946

Table XVII

Managers' Project-Level Idiosyncratic Risk Pricing - Real Option Effect (1)

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, year t, and portfolio k level. For this specification, the projects' internal rate of return used to estimate the firms' discount rate are obtained using a real option value decision rule. Instead of assuming that managers find it optimal to investment whenever the projects discounted value of cash flow is greater than the cost of investment, I assume that the optimal investment trigger is the real option optimal threshold. See appendix C for a detailed discussion of the estimation strategy. For the Kill test, the goal is to find the level at which the real option calibration eliminate my results for the paper main specification (column 6). To implement that, in the real option calibration, I multiplied the idiosyncratic risk variable by 28.8%, such that the coefficient for the idiosyncratic risk variable (β_1) is no longer statistically significant. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$					
	+0%			Kill test (Idiosyncratic Risk **+28.8%**)		
	(1)	(2)	(3)	(4)	(5)	(6)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	4.299***	1.148**	1.413***	3.122***	0.337	0.542
	[6.21]	[2.31]	[3.46]	[5.62]	[0.89]	[1.64]
(β_2) $Budget_{i,t}$		-0.006			-0.006	
		[-1.36]			[-1.38]	
(β_3) $Assets_{i,t}$		0.003*			0.003*	
		[1.65]			[1.68]	
Firm Fixed $Effect_i$	No	Yes	No	No	Yes	No
Year Fixed $Effect_t$	No	Yes	No	No	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	Yes	No	No	Yes
R-Squared	0.079	0.610	0.828	0.055	0.619	0.835
F-Statistics	38.606	3.144	11.964	31.566	1.371	2.696
Observations	2716	2716	2716	2716	2716	2716

Table XIIX
Managers' Project-Level Idiosyncratic Risk Pricing - Real Option Effect (2)

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket.. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* , year *t,* and portfolio *k* level. In this regression specification, the analysis is only performed on a subsample of projects for which the time to expiration is expected to be close to zero, making the real option optimal exercise threshold (V*) close to the projects investment cost (I). The variable *Project's Average Idiosyncratic Risk* is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	10.904***	6.567***	5.661***	5.638***	5.655***	5.638***	5.896***
	[6.75]	[5.27]	[4.59]	[4.59]	[4.59]	[4.59]	[5.09]
(β_2) $Budget_{i,t}$				0.006		0.009*	
				[1.39]		[1.82]	
(β_3) $Assets_{i,t}$					0.001	-0.002	
					[0.60]	[-0.96]	
Firm Fixed $Effect_i$	No	Yes	Yes	Yes	Yes	Yes	No
Year Fixed $Effect_t$	No	No	Yes	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	No	No	No	Yes
R-Squared	0.22	0.64	0.67	0.67	0.67	0.67	0.84
F-Statistics	45.521	27.772	21.085	10.580	10.550	7.046	25.946
Observations	1,642	1,642	1,642	1,642	1,642	1,642	1,642

Table XIX
Managers' Project-Level Idiosyncratic Risk Pricing - Leverage Effect

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i*, year *t*, and portfolio *k* level. The *Leverage* variable corresponds to the firms' book leverage calculated using the firm 10-k annual statement. Detailed calculations are available in appendix A.2. The analysis is restricted to the set of firms available in Compustat for which the necessary variables was available. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t,k}$			
	(1)	(2)	(3)	(4)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t,k}$	15.906*	16.050*	15.602*	13.430*
	[1.91]	[1.90]	[1.87]	[1.95]
(β_2) $Budget_{i,t}$			0.003	
			[0.22]	
(β_3) $Assets_{i,t}$		0.006	0.004	
		[0.71]	[0.45]	
(β_4) $Leverage_{i,t}$	-7.783	-6.939	-7.043	
	[-0.55]	[-0.48]	[-0.50]	
(β_5) $Leverage_{i,t}$ * Projects' Average Idiosyncratic $Risk_{i,t,k}$	13.507	12.965	12.969	21.128
	[0.52]	[0.50]	[0.51]	[0.71]
Firm Fixed $Effect_i$	Yes	Yes	Yes	No
Year Fixed $Effect_t$	Yes	Yes	Yes	No
Firm-Year Fixed $Effect_{i,t}$	No	No	No	Yes
R-Squared	0.352	0.352	0.318	0.626
F-Statistics	2.303	2.013	2.892	2.386
Observations	918	918	918	918

Table XX
Managers' Project-Level Idiosyncratic Risk Pricing - Futures Price

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1995 to 2010. The unit of observation in the underlying table is at the firm *i* , year *t* , and portfolio *k* level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). In this regression specification, the project's internal rate of return is estimated using the *36-month Bloomberg Natural Gas Futures* prices instead of the EIA three-year price forecast. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$				
	(1)	(2)	(3)	(4)	(5)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	7.904***	7.906***	7.905***	7.902***	8.130***
	[3.47]	[3.47]	[3.48]	[3.47]	[3.95]
(β_2) Budget$_{i,t}$		-0.004		-0.005	
		[-0.64]		[-0.79]	
(β_3) Assets$_{i,t}$			-0.001	0.002	
			[-0.11]	[0.32]	
Firm Fixed Effect$_i$	Yes	Yes	Yes	Yes	No
Year Fixed Effect$_t$	Yes	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	No	Yes
R-Squared	0.540	0.540	0.540	0.540	0.780
F-Statistics	12.063	9.331	6.325	6.908	15.629
Observations	3,416	3,416	3,416	3,416	3,416

Table XXI
Managers' Project-Level Idiosyncratic Risk Pricing - EIA State's Wellhead Price

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm *i* , year *t,* and portfolio *k* level. *Project's Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year portfolio (i.e., the high or low idiosyncratic risk portfolio). In this regression specification, the project's internal rate of return is estimated using the wellhead spot price specific to each state (Source: https://www.eia.gov/dnav/ng/ng_prod_whv_a_epg0_fwa_dpmcf_a.htm) instead of the EIA price forecast. The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate (%)$_{i,t,k}$				
	(1)	(2)	(3)	(4)	(5)
(β_1) Projects' Average Idiosyncratic Risk$_{i,t,k}$	8.050***	8.042***	8.049***	8.057***	8.066***
	[3.05]	[3.07]	[3.05]	[3.05]	[3.18]
(β_2) Budget$_{i,t}$		0.005		0.011	
		[0.58]		[0.63]	
(β_3) Assets$_{i,t}$			0.000	-0.003	
			[0.07]	[-0.57]	
Firm Fixed Effect$_i$	Yes	Yes	Yes	Yes	No
Year Fixed Effect$_t$	Yes	Yes	Yes	Yes	No
Firm-Year Fixed Effect$_{i,t}$	No	No	No	No	Yes
R-Squared	0.460	0.460	0.460	0.460	0.736
F-Statistics	9.323	9.512	4.696	8.364	10.130
Observations	3,946	3,946	3,946	3,946	3,946

Table XII
Managers' Project-Level Idiosyncratic Risk Pricing - Alternative Design

This table reports coefficient estimates from an OLS regression for the effect of projects' idiosyncratic risk on firms' discount rate, and t-statistics robust to heteroskedasticity and within-firm dependence in bracket. The time period of the sample is from 1983 to 2010. The unit of observation in the underlying table is at the firm i, and year t level. *Projects' Average Idiosyncratic Risk* denotes the average projects' idiosyncratic risk measure for each firm-year, scaled by its standard deviation (i.e., one portfolio per firm-year). The variable Project's Average Idiosyncratic Risk is scaled by its standard deviation to simplify the lecture of the table and facilitate its comparison with the other regression tables. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Discount Rate $(\%)_{i,t}$					
	(1)	(2)	(3)	(4)	(5)	(6)
(β_1) Projects' Average Idiosyncratic $Risk_{i,t}$	12.088***	7.041***	5.829***	5.834***	5.821***	5.817***
	[6.79]	[6.49]	[5.99]	[5.99]	[5.97]	[5.96]
(β_2) $Budget_{i,t}$				-0.003		-0.007
				[-0.90]		[-1.20]
(β_3) $Assets_{i,t}$					0.001	0.004
					[0.55]	[1.10]
Firm Fixed $Effect_i$	No	Yes	Yes	Yes	Yes	Yes
Year Fixed $Effect_t$	No	No	Yes	Yes	Yes	Yes
R-Squared	0.286	0.718	0.745	0.745	0.745	0.745
F-Statistics	46.049	42.055	35.869	18.293	18.410	12.649
Observations	1,973	1,973	1,973	1,973	1,973	1,973