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Real Options Analysis of Oil and Gas Resource Development for Independent E&P Firms in the North America*

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Since the beginning of the global oil crisis in the mid-2000s, oil and gas prices have been more volatile than other commodity prices. Accordingly, it is increasingly important for the independent E&P companies that are relatively vulnerable to market uncertainty to choose appropriate additional reserves of oil and gas. This paper provides a real options framework for analyzing the reserve replacement decisions of independent E&P companies, considering uncertain revenues and irreversible costs. The model considers the extraction cost per unit well associated with the remaining reserve level per well and instant production. Focusing on the North American E&P companies, threshold levels of oil and gas prices are identified for economic feasibility, above which it is optimal to undertake investment for reserve additions. The results indicate that the relative gains from gas E&P projects are steadily decreasing, primarily because of lowered gas prices triggered by recent gas development booms in the North America. The policy implications from this finding support a more conservative strategy and increased attempts in the field of gas development projects.

JEL Classification: Q2, D8
Keywords: Independent E&P, Real Options, Uncertainty, Investment

I. Introduction

Rising oil prices since the mid-2000s have triggered a reshaping of energy mix and diversification globally. The emerging role of gas is a noticeable change because of the development of shale gas in North America. As volatilities in the oil and gas markets intensify because of resource development booms and the related

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competitive environment, it is increasingly important to examine both the relative merits of oil and gas development and market uncertainty and resource development costs. In addition, such feasibility studies of oil and gas development project may provide valuable input to resource development plans for various oil and gas exploration and production (E&P) companies.

E&P companies are classified into three categories: national, international major and independent E&P companies. Each has unique characteristics, thus their business strategies will differ in response to changes in market conditions. Unlike the other types of E&P companies, such as national oil companies (NOCs) or major international oil companies (IOCs), the relative business scale of independent E&P companies is generally small, thereby defining them as price takers. This complicates investment decision-making by independent E&P companies because their investment portfolio construction may be substantially influenced by the volatilities in oil and gas prices. This paper focuses exclusively on the development of analytical tools for independent E&P companies to assess the project feasibility of oil and gas development, accounting for resource price uncertainty.

Because independent E&P companies have relied largely on commercial and investment banks to finance their exploration business, they are more vulnerable to the financial risks associated with a high dependency on debenture capital and are more sensitive to the changes in market prices. To overcome these shortcomings, they continue to achieve technical innovation, and they endeavor to have pioneering competitive advantages over the IOCs and NOCs. It is also important to gain market advantage through the development of unconventional oil and gas projects and to secure the quality of exploration by exploring for new resources to maintain a reserve replacement ratio greater than one. Recently, many E&P companies are finding it challenging to replace their reserves and to enhance their capacity because of increasing competition. This problem is becoming more complicated, particularly because of recent shale gas development that requires more accurate and conservative assessments of oil and gas reserve portfolios.

Considering the aforementioned factors, this paper focuses on analyzing the economic feasibility of reserve replacement investments in the oil and gas business in view of resource price uncertainty. More specifically, reserve replacement investments generally have two important characteristics that must be explicitly considered during the course of rational decision-making. First, they inevitably incur enormous sunk costs from project inception, thus creating irreversibility. Second, the investment involves a decision whether to invest immediately or to delay under market uncertainty. As manifested by Dixit and Pindyck (1994) among others, E&P companies have options to optimally start the project only when sufficient profits are expected after considering irreversibility and market uncertainty.

For this purpose, a real options analysis is employed in this paper as an analytical approach to measuring the value of projects. E&P projects involve decisions regarding production levels and resource exploration. This paper develops a model to incorporate optimal production decisions into the real options model; threshold levels of oil and gas resources are then identified to support investment. Based on the presented real options model, this paper also provides empirical analysis to investigate the economic feasibility of independent E&P firms who are active in the North American business, and it attempts to determine whether there is a firm size-specific nature of oil and gas project investments.

Extractive activity in nonrenewable resources is influenced by the price of each product. A firm's traditional production decision models suggest that production occurs when the present value of cash flows from the production exceeds the opportunity cost of the employed capital. The real options models introduced by Brennan and Schwartz (1985) and Dixit and Pindyck (1994) present analytical frameworks for such decision-making. Mason (2001) suggests an entry-exit model that considers resource scarcity as a novel feature of non-renewable resources. Dias et al. (2004) adopt Monte Carlo simulations to find an optimal development strategy for oil fields when considering production alternatives. Although this paper is consistent with the existing literature on optimal investments in non-renewable resource development, the paper focuses more specifically on the reserve replacement activities of North American independent E&P companies. The trading of conventional oil and gas resources has decreased, whereas non-conventional assets, including shale gas and tight oil, are experiencing rapid development.

After developing an optimal investment model to allow rational decision making on reserve replacement investments, a panel regression is performed to consolidate the empirical findings with the presented model. The analysis of appropriate threshold levels for resource development shows the steadily declining profitability of gas investments since the mid-2000s. Consequently, oil and gas development are still economically feasible in the North American region; however, profitable conditions for gas development have diminished compared to those for oil development. Hence, the results may suggest a more conservative strategy in exploration and production activities in the gas business. In addition, there are policy implications, particularly associated with the resource development policies of publically owned energy companies in developing countries that attempt to extend their business in to North America by acquiring independent E&P companies.

This paper is structured as follows. Section 2 presents a model to derive the optimal value function and obtain the optimal investment thresholds. Extraction cost per unit in response to the remaining reserve levels and production levels is considered. An empirical analysis is presented in Section 3, along with various sensitivity analyses with respect to key parameters. Finally, Section 4 presents the concluding remarks and suggestions for further works associated with oil and gas resource development projects.

II. Model

Suppose that a firm in the market for oil and gas resources considers a development investment. An initial attempt to develop a new oil or gas field involves an initial cost I_i where the subscript denotes oil $(i=o)$ or gas $(i=g)$. This cost is largely irreversible because of its sunk cost property. The prices of oil and gas at each instant of time are denoted as $P_o(t)$ and $P_g(t)$, respectively.

We introduce a general assumption such that the extraction costs and the level of reserves are inversely related to reflect the so-called 'stock effect' (Pindyck, 1978 and 1980), Devarajan and Fisher (1981). That is, the resource extraction cost is likely to increase as the accumulated size of resource extraction up to that time increases. More recently, Lin and Wagner (2007) suggest that, in the absence of additional exploration, the extraction cost function incorporates the stock effect by including the amount of cumulative extraction. However, we consider that the extraction cost does not rely on the firm's aggregate reserves; it relies on the remaining reserves *per* well because it is possible to have several deposits in one firm (Livernois and Uhler, 1987). Hence, we specifically focus on the relationship of the extraction costs and the remaining reserves per well. Consequently, the extraction cost per unit $\delta_i(t)$ at every instant time is the quadratic function of the remaining level of reserve per well $R_i(t)$ and instant extraction level $q_i(t): \delta_i(t) = CR_i(t)^{\varepsilon} q_i(t)^{\varphi}$ where C is constant. Note that ε and φ are the reserve and extraction elasticity of cost, respectively. Because the instant profit flow of the oilfield development project is $\pi_i(t) = P_i(t)q_i(t) - \delta_i(t)q_i(t)$, it is redefined as equation (1):

$$\pi_i(t) = P_i(t)q_i(t) - CR_i(t)^{\varepsilon} q_i(t)^{\varphi+1} \tag{1}$$

The price of the resource is assumed to follow an exogenous random process of a geometric Brownian motion:

$$dP_i(t) = \mu_i P_i(t)dt + \sigma_i P_i(t)dz \tag{2}$$

where dz is the increment of a standard Wiener process. Note that μ_i and σ_i are the drift and volatility parameters, respectively, and they are time invariant. Equation (2) implies that the price of the resource is initially known; however, the future price is rather stochastic, following log-normal distribution with a mean $(\mu_i - \frac{1}{2}\sigma_i^2)t$ and variance $\sigma_i^2 t$. Let $F^i(P_i(t))$ denote the value of waiting to invest or the value of an option to invest, and $V^i(P_i(t))$ denote the value of a project. The time subscript t is now suppressed for notational convenience unless otherwise necessary.

The nature of this decision problem is similar to those studied by Brennan and Schwartz (1985) and Dixit and Pindyck (1994). The Bellman's fundamental equation of optimality for the project is given by:

$$\rho V^i = \max\left\{\pi_i + \frac{1}{dt}E\left(\frac{\partial V^i}{\partial t}dt + \frac{\partial V^i}{\partial P_i}dP_i + \frac{\partial^2 V^i}{\partial P_i^2}(dP_i)^2\right)\right\} \tag{3}$$

where ρ is the discount rate. The resulting Hamiltonian-Jacobi-Bellman (HJB) equation, using the Ito's lemma, is given by:

$$\max_{q_i}\left\{P_i q_i - CR_i^{\varepsilon} q_i^{\varphi+1} + \mu_i P_i V_P^i + \frac{1}{2}\sigma_i^2 P_i^2 V_{PP}^i\right\} = \rho V^i \tag{4}$$

The first order condition for the optimal level of extraction from equation (4) is obtained by differentiating (4) with respect to q_i:

$$q_i^* = \left(\frac{P_i}{(\varphi+1)CR^{\varepsilon}}\right)^{\frac{1}{\varphi}} \tag{5}$$

Then, the optimality condition for instant extraction, as expressed in equation (5), is substituted into equation (4) to obtain the constraint-Hamiltonian-Jacobi-Bellman (constraint-HJB) equation:

$$X^{\frac{1}{\varphi}} P_i^{\frac{\varphi+1}{\varphi}}\left(1 - \frac{1}{\varphi+1}\right) + \mu_i P_i V_P^i + \frac{1}{2}\sigma_P^2 P_i^2 V_{PP}^i - \rho V^i = 0 \tag{6}$$

where $X = \frac{1}{(\varphi+1)CR^{\varepsilon}}$. The first component of equation (6) represents a firm's instantaneous profit flow under the optimal level of extraction.

The solution of equation (6), which is the optimal value function, is composed of the general solution and particular solution components. The general solution derived from the homogenous equation may be interpreted as speculative components of the project. The particular solution derived from the non-homogenous equation represents the total expected present value of the profit from the operation.

First, the general solution to the homogeneous component of equation (6) can be expressed as $V^i = BP_i^{\beta}$, where B is a constant that is not yet determined and the parameter β shall be defined as follows. Using $P\partial V^1 / \partial P = \beta V^i$ and $P^2\sigma^2\partial^2 V^i / \partial P^2 = \beta(\beta-1)V^i$ verifies that the unknown parameter β must satisfy the characteristic equation:

$$-\rho + \mu_i\beta + \frac{1}{2}\beta(\beta-1)\sigma_i^2 = 0 \tag{7}$$

which is a quadratic function that allows two values of β, one is positive, and the other is negative. More specifically, the two values are $\beta_1 = 0.5 - \mu_i / \sigma_i^2 + \sqrt{[\mu_i / \sigma_i^2 - 0.5]^2 + 2\rho / \sigma_i^2} > 1$, and $\beta_2 = 0.5 - \mu_i / \sigma_i^2 - \sqrt{[\mu_i / \sigma_i^2 - 0.5]^2 + 2\rho / \sigma_i^2} < 0$. Thus, the general solution of equation (6) can be expressed as the linear combination of the form:

$$V^i = B_1 P_i^{\beta_1} + B_2 P_i^{\beta_2} \tag{8}$$

Next, the particular solution to the non-homogeneous component can be obtained from equation (6) as follows:

$$V^i = X^{\frac{1}{\varphi}} p^{\frac{\varphi+1}{\varphi}} \left(\frac{1}{N} - \frac{1}{N(\varphi+1)} \right) \tag{9}$$

where $N = (\rho - \mu_P) - (2\mu_P + \sigma^2)/2\varphi - \sigma^2 / 2\varphi^2$. Thus, the complete solution of equation (6) can be given by

$$V^i = B_1 P_{it}^{\beta_1} + B_2 P_{it}^{\beta_2} + X^{\frac{1}{\varphi}} p_{it}^{\frac{\varphi+1}{\varphi}} \left(\frac{1}{N} - \frac{1}{N(\varphi+1)} \right) \tag{10}$$

As explained earlier, the last term of this particular solution is the expected discounted value when the firm is required to keep operating while the resources are being exploited. The first two terms represent speculative components of the firm's value when the firm invests in the project. The appropriate boundary condition for the value of the project is $\lim_{p\to 0} V^i(p) = 0$ because the resource development does not carry any value when the resource price is zero. Hence, the second component of equation (10) must be zero by allowing $B_2 = 0$. Then, the value of the oilfield development project is simplified to:

$$V^i = BP_i^{\beta_1} + X^{\frac{1}{\varphi}} p_i^{\frac{\varphi+1}{\varphi}} \left(\frac{1}{N} - \frac{1}{N(\varphi+1)} \right) \tag{11}$$

The first term in RHS of equation (11) represents an investment option and the second term is the discounted fundamental value of oil development project. We now consider the optimal value of the option to invest, $F^i(P_{it}, t)$. In this case, the Bellman's fundamental equation of optimality for a value of option to invest is:

$$\mu_i P_i F_P^i + \frac{1}{2}\sigma_i^2 P_i^2 F_{PP}^i - \rho F^i = 0 \tag{12}$$

Similar to equation (6), the general solution to the homogeneous equation can be expressed in the form of $F^i = AP_{it}^{\beta}$. Following a procedure similar to that outlined above, that the final solution is given by:

$$F^i = AP_i^{\beta_1} \tag{13}$$

where β_1 is the positive root of equation (7). The value of the option to invest and the value of the project can be revised as follows:

$$F^i = AP_i^{\beta_1}, \tag{16}$$

$$V^i = BP_i^{\beta_1} + X^{\frac{1}{\varphi}} p_i^{\frac{\varphi+1}{\varphi}}\left(\frac{1}{N} - \frac{1}{N(\varphi+1)}\right) \tag{17}$$

We are now in a position to determine the investment threshold that ensures sufficient investment values in the presence of uncertainty and irreversibility. To identify the optimal threshold price P_i^*, two optimality conditions must be satisfied as presented in equations (18) and (19). The first condition is the value-matching condition that requires that the value gains attributed to the investment should be equal to the cost of the initial investment. The second condition, known as the smooth pasting condition, requires that marginal changes in the option value F^i, at the threshold price, must be equal to that for the value of the project V^i. The optimal threshold price P_i^* is obtained from the following value-matching and smooth-pasting conditions:

$$AP_i^{\beta_1} + I = BP_i^{\beta_1} + X^{\frac{1}{\varphi}} p_i^{\frac{\varphi+1}{\varphi}}\left(\frac{1}{N} - \frac{1}{N(\varphi+1)}\right), \tag{18}$$

$$\beta_1 AP_i^{\beta_1 - 1} = \beta_1 BP_i^{\beta_1 - 1} + \frac{\varphi+1}{\varphi} X^{\frac{1}{\varphi}}\left(\frac{1}{N} - \frac{1}{N(\varphi+1)}\right) P_i^{\frac{1}{\varphi}} \tag{19}$$

Because we have two unknowns, optimal threshold P_i^* and option constant term $M = A - B$, and the two equations (18) and (19), the optimal threshold value P_i^*

can be precisely identified as below:

$$P_i^* = \left(\frac{N \cdot Z \cdot I}{W}\right)^{\frac{\varphi}{\varphi+1}} \tag{20}$$

where $W = (X^{\frac{1}{\varphi}} - \frac{X^{\frac{1}{\varphi}}}{\varphi+1})$, $N = (\rho - \mu_i) - \frac{(2\mu_i + \sigma^2)}{2\varphi} - \frac{\sigma^2}{2\varphi^2}$, and $Z = \frac{\beta_1}{\beta_1 - \frac{\varphi+1}{\varphi}}$.

N represents the volatility-adjusted discount rate and Z is interpreted as a measurement of hysteresis that accounts for reluctance of investment. The option constant term $M = A - B$ can be derived from equation (18) once P_i^* is identified. Simple comparative statics reveal that the change in threshold price in response to the increasing price volatility $(\partial P_i^* / \partial \sigma)$ does not necessarily imply investment delay; rather, it is determined by the size of the positive and negative effects embedded in the volatility-adjusted discount rate and hysteresis, respectively.

III. Empirical analysis

We now proceed with the empirical analysis using data on independent E&P firms obtained from the Korea Energy Economics Institute and Energy Information Administration. The data includes total oil and gas reserves, developed oil and gas reserves, reserves per well, annual production levels and operation and development costs. The study covers 57 independent E&P companies actively working in the North American region. The data includes the years from 2004 to 2008.

As conventional oil and gas opportunities become more competitive, companies are now drilling in ever-deeper waters offshore and putting more focus on unconventional natural gas reservoirs, such as shale gas and oil sand. However, the competitive shale field and oil sand environments are becoming more intense and some IOCs are committing substantial investments to this business, thereby lowering the natural gas prices. As a result, there is growing interest in the more cautious construction of investment portfolios in the unconventional oil and gas business.

We begin with the examination of the initial investment costs. There are essentially two methods of reserve replacement. The first method involves finding a new source of oil and gas, which is commonly referred to as organic or drill bit reserve replacement. The second method involves buying properties from another company or buying an entire company, which is called an acquisition. Considering these two strategies, the initial investment cost I_i in this paper includes costs of acquisition, exploration, development and finding costs. We use the lifting costs per barrel as the unit extraction cost δ_{it}. Lifting costs include transportation costs, labor costs, costs of supervision, costs of operating the pumps, electricity, repairs and depreciation. Drift rates and volatilities in oil and gas prices from January 1997 to December 2008 are obtained from the daily data provided by the Energy Information Administration (EIA). In the later part of the analysis, using the parameters estimated from the empirical data, the optimal investment thresholds of the independent E&P companies working in the oil and gas sector are identified.

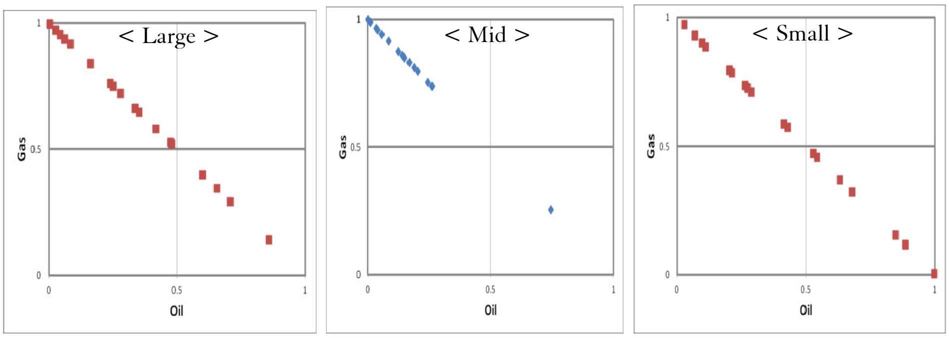
In this paper, independent E&P companies are categorized as small, mid and large-size, based on the firms' total revenues. The sum of total proven reserves is presented in Table 1; in 2008, the 57 independent companies share 20% of the total proven reserves of oil and gas in the U.S. The share of independent E&P companies is consistently increasing, which indicates increasing working activities to preempt resource development. Independent companies possess 24% of U.S proven oil reserves and 19% of U.S proven gas reserves. The independent E&P companies' shares in both oil and gas reserves are steadily increasing. Increased proven reserves are mainly occupied by the large-size companies; the increase in proven reserves of small and mid-size companies is less than that of large-size companies.

[Table 1] Total proven reserves of 57 independent E&P firms

		2004	2005	2006	2007	2008
Oil and Gas (1,000 MMBOE)	Total US (A1)	57.3	59.8	60.3	65.5	64.5
	Total E&P (B1)	9.3	10.6	11.5	12.2	12.9
	% (B1/A1)	16	18	19	19	20
Oil (1,000 MMbbl)	Total US (A2)	21.4	21.8	21.0	21.3	19.1
	Total E&P (B2)	3.8	4.4	4.6	4.9	4.5
	% (B2/A2)	18	20	22	23	24
Gas (1,000Bcf)	Total US (A3)	208.3	220.6	228.2	256.4	263.3
	Total E&P (B3)	33.1	37.1	41.2	44.1	50.3
	% (B3/A3)	16	17	18	17	19

Source: EIA (Energy Information Administration).

[Figure 1] Ratio of proven reserves of oil and gas (2008)



A typical finding from Figure 1, which presents the ratios of proven reserves of oil and gas for the 57 independent companies in the year 2008, is that the proven reserves ratio of oil and gas in large and small-size firms is relatively evenly distributed, whereas the reserves in mid-size firms are more concentrated on natural gas. Natural gas oriented companies are mainly distributed in the mid-size category. For example, Petrohawk Energy Corporation, a pioneer of E&P for shale gas, and CNX Gas Corporation, one of the most productive coalbed methane gas (CBM) producers in the U.S., are classified as mid-size firms.

Among the 57 companies, only two companies have natural gas reserves exclusively, and only one company is specialized to only oil reserves. The other 54 companies possess both oil and natural gas reserves, with varying ratios between them. The average developed reserves for the 57 independent companies account for approximately 66% of their total proven reserves, irrespective of their size.

The investment scale of these 57 independent E&P companies from 2004 to 2008 is approximately 200 billion U.S. dollars, an average of 700 million U.S. dollars every year per firm. The annual investment growth rates during the corresponding period for small, mid-size and large-size firms are 28%, 21% and 14%, respectively. The production costs usually consist of lifting costs and depreciation, depletion and amortization costs (DD&A costs). From 2004 to 2008, the lifting cost was stabilized at approximately \$10/BOE, and the cost of DD&A rapidly increased from approximately \$10/BOE to more than \$40/BOE. This significant increase in DD&A costs occurred because large-size firms increased their investment scale in exploration activities, particularly in 2006. The aggressive investment resulted in substantial profits from both oil and gas production. The compound annual growth rate (GAGR) for annual profit is 14%, which is mainly driven by 19% of oil price GAGR and 9% of gas price GAGR.

We next consider two different types of projects in this paper to further clarify investment types. The Type I project finds and develops new oil and gas fields. A firm's total proven reserves would be extended through the Type I project, which incurs relatively significant initial sunk costs. These initial costs include acquisition, finding, exploration and development costs. Second, there may be a project to transform undeveloped oil and gas fields into developed reserves that could be readily extracted. This type of project is called the Type II project. The initial cost of the Type II project only includes development costs; hence, the initial cost of this project is less than for the Type I project.

The parameters of φ, ε are to be obtained by estimating the following extraction cost function (21), which is originated from $\delta_i(t) = CR_i(t)^{\varepsilon} q_i(t)^{\varphi}$, to determine the existence of stock effects. Similar effects for resource stocks and contemporaneous production are found in Lin and Wagner (2007). Thus, this cost function indicates a possible association of firms' remaining reserves per well and the concurrent production level.

$$\log\delta_i = \log C + \varepsilon \log R_i + \varphi \log q_i + u_i \tag{21}$$

where $u_i \sim i.i.d.N(0,\sigma^2)$. The estimation results from the pooled regression from 2004 to 2008 are reported in the table below.

[Table 2] Estimated parameters of the cost function

Oil		Gas	
ε	φ	ε	φ
-0.042* (0.025)	0.036** (0.016)	-0.038* (0.023)	-0.023* (0.013)

*: 10% **: 5% ***: 1% significant level.

The results indicate that the unit extraction cost of oil is positively related to the production level and negatively related to the remaining reserves per well, whereas the gas extraction cost is negatively related to the reserves and production level. There exist stock effects on the oil and gas extraction activity, indicating an inverse relationship between unit extraction cost and remaining reserves; the extraction costs tend to rise as the reserves in a single deposit decrease. The directional change of oil and gas extraction costs, with respect to the instant production level, is different. The extraction cost and production level of oil move in identical directions; extraction costs increase when the production level increases. The gas extraction cost is negatively related to the production level.

Therefore, the natural gas prices tend to plummet when the market supply slightly exceeds market demand. The transportation of natural gas is closely linked to its storage. The storage of natural gas in its liquid form requires the use of specialized refrigeration equipment. Hence, it is necessary to have sufficient equipment and well-organized transport networks to achieve a sustainable production level. Firms with large-scale natural gas production possess such specialized storage equipment or well-established pipeline transport networks. They are firms specialized in not only the exploration and production technology but also the storage and transportation networks. We can infer that the inverse relationship between extraction cost and production level may be attributed to these features of the gas industry.

A unique index is introduced to provide an intuitively simple measure to assess the economic feasibility of the reserve replacement project: p/p^*. If the index p/p^* is greater than one, then the project can be regarded as economically feasible; otherwise, the project is not profitable because the market price is not high enough to exceed the minimum level of required price P_i^*. Table 3 provides the p/p^* results for small firms, mid-size firms and large-size firms for the Type I project. Table 4 presents p/p^* for the Type II project.

[Table 3] Estimated values of investment index (Type Ⅰ project)

		2004	2005	2006	2007	2008	Annual growth (%)
Small-firm	p_o / p_o^*	4.30	5.85	7.12	7.75	11.23	28
	p_g / p_g^*	4.03	6.18	5.13	5.27	6.98	18
	$(p_o / p_o^*)/(p_g / p_g^*)$	1.06	0.94	1.38	1.47	1.60	13
Mid-firm	p_o / p_o^*	3.49	4.88	5.93	6.43	9.30	29
	p_g / p_g^*	5.43	8.46	6.59	6.67	8.00	14
	$(p_o / p_o^*)/(p_g / p_g^*)$	0.64	0.58	0.90	0.96	1.16	18
Large-firm	p_o / p_o^*	4.60	6.14	7.28	8.39	11.69	27
	p_g / p_g^*	3.59	5.39	4.20	4.41	5.73	16
	$(p_o / p_o^*)/(p_g / p_g^*)$	1.28	1.14	1.73	1.90	2.04	15

Table 3 and Table 4 show that both oil and gas projects were economically feasible throughout the period of 2004-2008 because $p / p^* > 1$. The profitable condition is steadily enhanced by the significant annual growth rates. The economic feasibilities of the oil and gas reserve replacement investments are different depending on the size of the firms. For example, for large firms and small firms, the oil reserve replacement project is more economically feasible than the gas project. For mid-size companies, however, gas reserve replacement is preferable to oil reserve replacement in spite of the higher volatility of natural gas prices. This result is consistent with the empirical observations found in Figure 1.

[Table 4] Estimated values of investment index (Type Ⅱ project)

		2004	2005	2006	2007	2008	Annual growth (%)
Small-firm	p_o / p_o^*	4.53	6.29	7.43	8.14	11.36	27
	p_g / p_g^*	4.41	6.61	5.18	5.41	6.97	15
	$(p_o / p_o^*)/(p_g / p_g^*)$	1.03	0.95	1.43	1.50	1.63	14
Mid-firm	p_o / p_o^*	3.28	4.52	5.49	6.19	8.85	29
	p_g / p_g^*	5.62	8.39	6.52	6.53	8.36	14
	$(p_o / p_o^*)/(p_g / p_g^*)$	0.58	0.53	0.84	0.95	1.06	19
Large-firm	p_o / p_o^*	4.48	5.27	7.18	7.91	11.40	27
	p_g / p_g^*	4.95	7.40	5.78	6.08	7.78	15
	$(p_o / p_o^*)/(p_g / p_g^*)$	0.91	0.71	1.24	1.30	1.47	18

There are several additional explanations for these results. First, the price of natural gas was more volatile than the price of oil during the period from 2004 to 2008. As suggested in the real options literature, larger volatility corresponds to a higher level of uncertainty, making the waiting option more valuable and generating a hysteresis effect on investment decisions. As a result, the optimal threshold price will be further elevated. Therefore, firms, particularly large and small-size firms in this case, become less willing to invest in new projects in the gas field, whereas the oil reserve replacement projects ensure higher profitability than gas projects. However, these explanations are not valid for the mid-size firms because the gas replacement project is preferable to the oil replacement project for them. We infer that this is because of the characteristics of the natural gas industry. The exploration and production of natural gas requires more advanced technologies and expertise than oil production, particularly for producing unconventional natural gas, such as shale gas and coalbed methane gas. Further, the storage and transportation of natural gas requires specialized equipment. Companies with such technologies and specialized equipment are primarily distributed in the mid-size category. In practice, therefore, the average level of revenue and production of mid-size companies are greater than that of large-size and small companies. The higher level of revenue and production reduces the extraction cost of natural gas, increasing the expected net present value for gas replacement projects. Consequently, for mid-size companies, gas reserve replacement is preferred to oil replacement activity.

The sensitivity analysis of several crucial parameters that may influence the optimal threshold prices is provided. Table 5 presents the values of the parameters that are used in this simulation.

[Table 5] Description of parameters <Oil>

μ_o	Annual drift rate of price	17%
σ_o	Annual volatility of price	41%
ρ	Annual discount rate	6%

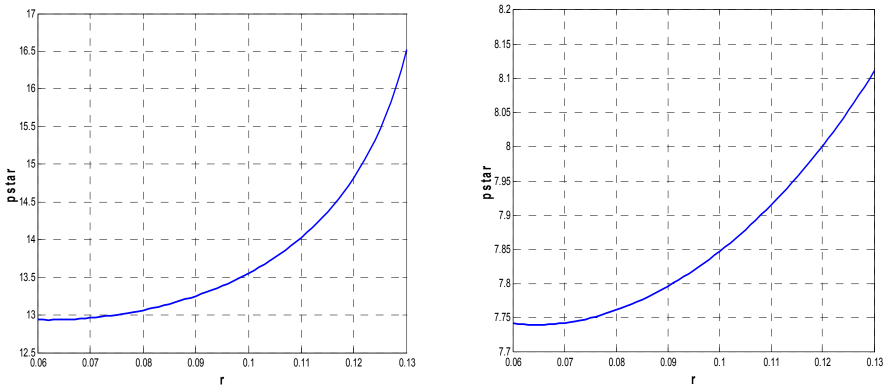
<Gas>

μ_g	Annual drift rate of price	27%
σ_g	Annual volatility of price	74%
ρ	Annual discount rate	6%

As we can see from Figure 2, a higher discount rate level increases the optimal threshold price level because the increased discount rate lowers the present value of the expected NPV of the project. Next, we check the effects of uncertainty and the remaining reserve per well on the optimal threshold price. Figure 3 shows that the optimal threshold price is decreasing in response to the increasing size of reserves per well. The result is intuitive because a sufficient level of reserves improves the possibility of lower unit extraction costs, thereby reducing the optimal threshold price as the expected net present value of the reserve replacement project increases by the diminishing costs of extraction. Another important variable is the volatility of oil and gas prices. The increases in price volatility can result in an increase in the optimal price level. The greater volatility increases the threshold price p^* because the firm must have a price well above the break-even price to be certain that the project has a positive expected NPV when the volatility is high.

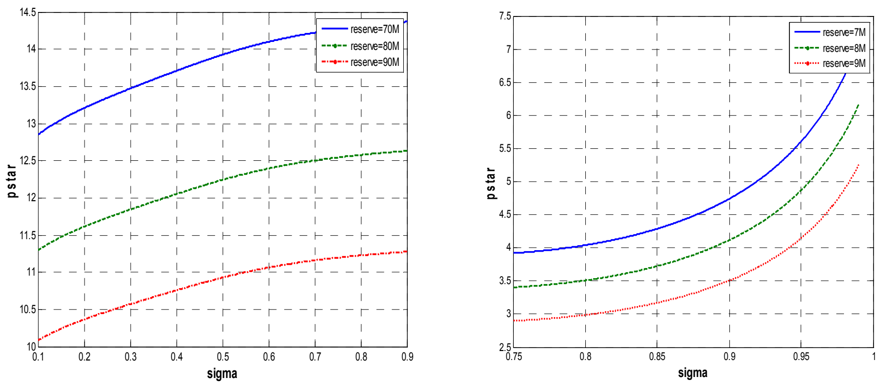
[Figure 2] Sensitivity analysis of p^* with respect to r

< Oil > < Gas >



[Figure 3] Sensitivity analysis of p^* with respect to σ

< Oil > < Gas >



We analyze how the threshold prices are to be related to the firm's new investment decision, considering the existing fundamental variables, such as the firms' cash flows and finding costs. Quirin et al. (2000) categorize the fundamental variables to evaluate the E&P firm's value into four broad theoretical areas: cash flows, production efficiency, stock price appreciation potential and growth. This paper only provides two theoretical categories, cash flows and production efficiency, because of the limitations of data for each firm. The firms' total cash flows and margin per BOE are the cash flow related variables, and the finding cost per BOE is a production efficiency variable. The cash flow variables could measure each firm's earnings, which are adjusted to mitigate accounting related problems for the new development investment. In addition, the production efficiency variables could measure how efficiently each firm is lifting and processing oil or gas resources and how efficiently each firm is expanding their reserves and productions.

We then estimate a panel regression using the firm's annual developed reserves replacement additions, the investment index p/p^* and the other fundamental variables for the 57 independent E&P companies. The estimation equation is presented as follows:

$$\Delta R_{it} = \beta_0 + \beta_1 FC_{it} + \beta_2 CF_{it} + \beta_3 MARGIN_{it} + \beta_4 \widehat{p_{it}} + u_{it} \tag{22}$$

where $u_{it} \sim iid.N(0, \sigma^2)$. ΔR_{it} denotes each firm's annual reserves replacement additions, and FC_{it} and CF_{it} are the finding cost per BOE and the total operating cash flow of the firm, respectively. $MARGIN_{it}$ represents a firm's margin per BOE and $\widehat{p_{it}}$ is the obtained investment index that is presented as p/p^*_{it}. We found that there are some missing total cash flow values, thus we only use the data from the 37 firms with no missing values.

First, we run a pooled OLS (ordinary least regression) (fixed effect and random effect) based on the yearly data from 2004 to 2008. Next, we conduct the likelihood test for the fixed effect to determine whether to reject the null hypothesis if there is no cross-sectional characteristic. The results suggest that fixed effect estimation is an appropriate estimation method compared with the pooled OLS. Further, we take the Hausman test to determine the consistency of random effect generalized least square (GLS) estimation and reject the null hypothesis that GLS is a consistent estimation. For that reason, we finally employ the fixed effects model with cross section GLS weights to control the heteroskedasticity of the error component. The estimation results are shown in Table 6.

In the oil reserve replacements, estimated coefficients are presented where three of four fundamentals are considered significant at the level of $p < 0.05$ or better. Among the fundamental variables, margin per BOE is statistically significant and its positive direction seems intuitively correct. The finding cost per BOE is negatively related to reserve replacement additions with statistical significance. Hence, it appears that the firm's reserve replacement investment reacts favorably in firms that possess higher margins and lower finding costs per BOE. However, the firm's total operating cash flows are not closely linked to the reserve replacement additions because it does not ensure statistical significance. The obtained investment index p / p^* is positively related to reserve additions with strong significance. Therefore, a majority of the independent companies appear to have considered the uncertainty attributed to the market price changes and irreversible features of reserve replacement investment when they decide whether to undertake oil replacement investments.

[Table 6] Estimated panel regression results

	ΔR_0	ΔR_g
Constant	12,122,528*** (3,614,947)	-59,796,171*** (16,899,350)
FC	-291,383** (125,780)	-246,457 (173,683)
CF	-0.0075 (0.0085)	0.0872*** (0.0265)
MARGIN	209,341*** (63,961)	-19,447 (49,778)
$\widehat{p_{it}}(p / p^*)$	3,580,686*** (553,067)	549,435 (2,206,289)
R^2 Adj	0.703	0.485

*: 10% **: 5% ***: 1% significance level.

By contrast, in gas reserve replacement investments, total operating cash flows exhibit positive relationships with reserve replacement; they possess the greatest statistical significance as an indicator to explain a firm's reserve replacement, whereas margin per BOE and the finding cost fundamentals are not significant. The index of economic feasibility p / p^* is also not significant in gas reserve replacement investment. This result leads us to conclude that there are other incentives for investing in oil and gas reserve replacement activities. The oil reserve replacement is closely related to the margin, the finding cost per BOE and the obtained investment index, which incorporates information on the current market price and production efficiency. Hence, these factors are directly associated with a firm's current net profits. The results may validate the evidence that the investment incentives for the addition of oil and gas reserves are different depending upon when the profits will be generated. Since the mid-2000s, the rate of oil price increase has been unprecedented and many immediate factors, such as low interest rates, are further contributing to this phenomenon. During 2005, the West Texas Intermediate (WTI) spot price reached $60 per barrel, and it later peaked at $147 in July 2008. The skyrocketing oil prices allowed the E&P companies to retain sufficient levels of oil reserves through reserve replacement investments to maximize corporate profits from current production. Consequently, the addition of reserve oil is closely related to the margin per BOE and the profitable market condition, which is measured in this paper as the investment index p / p^*. These factors are linked to the current price level. Hence, we may infer that the firms are concentrating more on maximizing their short-term profits when they invest in oil reserve replacements.

However, the results of gas reserve replacement provide further evidence that the relationships are different from for oil investments. Many energy-related agencies predict that natural gas will face a 'golden age' in the next several decades. According to the Future of Natural Gas (MIT Energy Initiative, 2010), abundant global natural gas resources increase the possibility of natural gas expansion in the economy, particularly in the electricity generation sector. Natural gas will thus assume an increasing share of the energy mix over the next several decades, particularly in the U.S. Unconventional gas, such as shale gas, will make an important contribution to future U.S. energy policies and CO2 emission efforts. The recent application of horizontal drilling and hydraulic fracturing technology to shale gas development is expected to increase the estimated resource reserves and total production levels of natural gas. EIA further predicts that natural gas will become a key part of natural energy policies, particularly in the electricity sector in developed countries. Natural gas offers many advantages compared with other fossil fuels, including relatively low greenhouse emissions, energy efficiency and abundant resources. In summary, natural gas will play a key role in the future U.S. energy mix, and the enormous future demand in natural gas will be sustained over the next several decades. Therefore, many independent E&P companies will be preparing for long-term sustainable profits when they invest in natural gas reserve additions. In fact, although the gas reserve replacement investments do not directly correspond to a firm's current profits, many companies invest in the gas replacement investments because they are primarily interested in securing long-term sustainable production in natural gas.

IV. Conclusions

Oil prices that have increased more than threefold during the 2000s dramatically reshaped energy resource markets by prompting more diversification efforts aimed at reducing oil dependency. As a result, gas development in the North American region was triggered and led to the so-called shale gas revolution. However, because of unprecedented competition between oil and gas, the relative market volatility of oil and gas has been a major concern in resource development planning not only for companies' operating in the private sector but also for national or public oil companies attempting to extend their business to overseas resource development projects. One typical example of strategy failure and the importance of market analysis is the case of the Korea National Oil Corporation (KNOC). KNOC invested in the Canadian energy company, Harvest Energy, during the bullish period in oil markets and later attempted to sell the company in a bearish period. Hence, it is critically important to analyze market conditions to make decisions on investments in the oil and gas business.

For this purpose, we introduce a real options model that accounts for uncertain revenues and irreversible costs for the examination of the reserve replacement activities of the 57 North American independent E&P companies. The uncertainty of revenues is the result of the resource price uncertainty and irreversibility of costs associated with property sunk costs. The model takes into consideration the extraction cost per unit that varies with the level of remaining reserves and instant production rate. After deriving the thresholds from the employed model, we estimate the parameters of the extraction cost function. The results indicate that the unit extraction costs of oil and natural gas respond in different directions with changes in the remaining reserves and production level. The sensitivity analysis for crucial parameters indicates that the level of reserves and extraction costs are inversely related, whereas market price volatility and extraction costs are positively related. The economic feasibilities of reserve replacement investments of oil and gas involve different scales depending on the producer's specialization and when the profits from the reserve replacement investments are expected. For firms classified in the large and small-size category, the oil replacement project is more feasible than the gas project. For the mid-size companies, however, gas reserve replacement is preferable to oil reserve replacement in spite of the higher volatility of natural gas prices. The finding that many specialized natural gas firms are classified into the mid-firm category is explained by real options perspectives. Furthermore, we conduct the panel regression analysis with respect to reserve additions and obtain threshold values to establish their relationships. The estimates provide further evidence that the inducements to invest in oil and gas reserve additions vary depending on the purpose of the investments. Oil reserve replacement investments appear to be focused on short-term profits rather than long-term production stability because of the current higher relative prices of oil; gas reserve replacement investments appear to be focused on long-term production stability in preparation for the 'golden age' of natural gas.

There are limitations to the present work. The assumption that uncertainty only results from the volatility of the oil and gas prices needs to be relaxed to secure additional reliability for the analysis. Introducing additional uncertainty, such as stochastic reserve, would allow richer implications. However, that would complicate the analysis because of the non-linearity of the value function. This problem should be considered in future studies.

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