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A Model of Natural Gas Exploration Effort in the Western Canadian Sedimentary Basin

by

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The undersigned certify that they read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled "A Model of Natural Gas Exploration Effort in the Western Canadian Sedimentary Basin" submitted by Beata H. Komierowski in partial fulfillment of the requirements of the degree of Master of Arts in Economics.

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Abstract

Price expectations play a central role in models of hydrocarbon exploration and supply. The standard empirical approach to incorporating prices into such models hinges on the assumption that agents form static or adaptive expectations. A re-examination of the validity of this assumption is warranted in consideration of the central proposition of the Efficient Market Hypothesis - that futures prices offer the optimal forecast of future spot prices. The present study compares the predictive power of futures prices and spot prices on determining exploration effort in the Western Canadian Sedimentary Basin. The evidence suggests that while spot prices have a negative and statistically insignificant effect on exploration effort, the influence of futures prices is positive, and well determined.

As a follow-up, recent developments in the theory of cointegration are employed, first, to test whether natural gas markets are efficient and second, to examine the interdependency between natural gas and petroleum futures markets.

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List of Acronyms

ADF	Augmented Dickey Fuller
AIC	Akaike Information Criterion
CAPP	Canadian Association of Petroleum Producers
ECM	Error Correction Model
EMH	Efficient Market Hypothesis
E&P	exploration and production
FE	fixed effects
IPS	Unit Root Test proposed by Im *et al.*
LNG	liquefied natural gas
MU	Maddala and Wu Unit Root Test
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
OLS	ordinary least squares
RE	random effects
Tcf	trillion cubic feet
US	United States
VECM	Vector Error Correction Model
WCSB	Western Canadian Sedimentary Basin
WTI	Western Texas Intermediate

Chapter 1

Introduction

Natural Gas is a significant contributor to the North American energy market. It ranks among the cleanest burning energy sources, and has a variety of industrial, residential, commercial, and electrical-power generating uses. At current production rates of 6.3 trillion cubic feet (Tcf) per year, the Western Canadian Sedimentary Basin (WCSB) is both the third largest natural gas producing region in the world[1], and the primary exporter to the United States (US). As electrical power generation in the US becomes increasingly dependent on natural gas and legislation concerning greenhouse gas emissions continues to provide incentives to convert to this cleaner burning fossil fuel, it is forecast that US natural gas demand will rise steadily into the foreseeable future (EIA, 2007). Thus, unless there is ample reason to believe that Canadian[2] pipeline imports can be readily and systematically substituted[3], the current contention is that additional demand pressure will be exerted on Canadian natural gas production.

This upward demand pressure is further exacerbated by the continued development of Alberta's oil sands. At sustained levels of high oil prices, harvesting

[1] Canada ranks after Russia and the US respectively in terms of natural gas production (CIA, 2007).
[2] Currently, over 98% of Canadian natural gas production comes from the WCSB. As such, throughout this thesis the terms Canadian and WCSB production will be used interchangeably.
[3] The EIA Natural Gas Monthly Report for June 2007 reported that in April 2007, Canadian natural gas pipeline exports to the US declined 8.8 % year over year. At the same time, imports of liquefied natural gas (LNG) increased symmetrically, offsetting the declines. These observations lead many analysts to infer that Canadian imports were being displaced by shiploads of LNG and to question the future role of Canadian natural gas exports to the US. It is important to note however, that the surge in LNG imports into the US was precipitated by the existence of a historically large differential between American and European gas prices, which created a unique arbitrage opportunity for LNG cargoes normally bound for Europe to travel across the Atlantic to the US market. Standard financial theory suggests that such arbitrage opportunities cannot exist for sustained periods of time. As such, this thesis assumes that this differential is temporary, and that Canadian exports will rebound when LNG cargoes return to their regular European destinations.

Alberta's unconventional oil reserves has become economically viable, and natural gas is a necessary input within this production process. As intracontinental trade of both natural gas and oil sands produced crude bitumen grows, understanding natural gas exploration in the WCSB becomes integral within the broader context of elucidating the North American energy market.

Seemingly unresponsive to the emergence of this two-front demand pressure, there has been a marked deterioration in the basin's exploratory rig count over the last year. Although it is customary among industry analysts to evaluate such trends in the context of overall "basin economics", the relevant empirical literature is thin. Motivated by the paucity of statistical support regarding these relationships, the current research seeks to develop the optimal empirical strategy for investigating natural gas exploration effort. Specifically, building upon the intertemporal framework typically employed in the theoretical literature, I plan to explicate the role of price expectations within the natural gas exploration effort supply equation.

The common empirical convention in modeling exploration effort has been to use either spot or historical prices as a proxy for expectations of future price, implicitly assuming that the firm forms static or adaptive price expectations. This view is dissonant from the conventional wisdom that explorationist firms, often look not at spot, but rather at futures markets when making their drilling decisions. My goal is to provide a formal examination of this hypothesis. Central to fulfilling this objective, first I introduce futures prices into an equation of exploration effort, and then, examine the dynamics which drive natural gas futures prices. Conditional on the hypothesis that the natural gas market is efficient, and as such, that futures price are the optimal predictor of next period commodity price, I conjecture that natural gas futures prices will have a significant, positive impact on exploration effort.

There are three parts to this thesis. Chapters 3 through 5 present empirical methods, data and results of each subsequent part. The corresponding objectives of the respective chapters are:

- to compare the explanatory power of futures prices versus conventionally-used spot prices in the natural gas exploration effort supply equation
- to examine the historical efficiency of natural gas markets
- to assess whether natural gas futures prices are cointegrated with petroleum futures prices, as proposed by contemporary financial theory.

Addressing the common criticisms in the literature concerning omitted variables bias, the current framework embeds WCSB panel data for three drilling depth categories into Kemp and Kasim's (2006) arguably superior empirical model of exploration effort. Utilizing a panel design structure allows me to control for the fact that drilling costs, geological characteristics and risk profiles vary significantly with drilling depth. As such, in the context of the present paper, fixed effects are reinterpreted as those rig depth-specific geological factors and features of capital which influence exploration effort. The model is then extended to include futures prices as a determinant of WCSB rig count, allowing for a comparison of the explanatory power of spot and futures prices on exploration effort. In accordance with expectations, I find that while spot prices have a negative and statistically insignificant effect on exploration effort, the influence of futures prices is positive and well determined. To my knowledge, no previous work has ever tested futures prices as a determinant of exploration effort or production supply.

Next, cointegration analysis is utilized to assess separately the efficiency and unbiasedness of natural gas futures markets. My findings have potentially broad policy implications, for if futures prices correctly anticipate the directional movement of future spot prices, public policy should be based on such market information. Conversely, if the informational content of futures is found to be insignificant, alternative forecasting methodologies should be considered. Although several works have previously attempted an investigation of market efficiency for natural gas, the question of unbiasedness has remained unaddressed. Applying the standard ordinary least squares (OLS) technique, my findings suggest that natural gas futures are efficient and unbiased for contracts of two and three month expiries, inefficient for contracts of four month expiries, and efficient but biased for long term, 36 month contracts. Buttressing OLS results with Johansen's Trace Test, I show that the natural gas market is efficient in the case of shorter (two to four month) term contracts, but that efficiency is rejected for the 36 month contract.

Finally, the interdependency between natural gas and petroleum futures markets is examined. In extrapolation of past findings, which show that natural gas and crude oil *spot* prices are cointegrated, I examine whether the same holds true for oil and gas *futures* prices of the same contract expiry horizons. Applying a basic error correction model (ECM) allows me to simultaneously embody the long run cointegrating relationship, and to characterize the dynamic adjustment process between these two futures price series. My data indicates that natural gas and crude oil futures prices are statistically cointegrated at a ratio of 7.8 to one.

Chapter 2 reviews both theoretical and empirical literature relating to all three parts of this thesis. An overall summary of findings is provided, and areas for further study are proposed, in Chapter 6.

Chapter 2

Literature Review

This chapter deals with an analytical survey of the literature of previous studies in this research domain. It begins with classical theories of oil and gas exploration and production (E&P), and proceeds to introduce more recent empirical models of petroleum supply. Next, a theoretical examination of futures market dynamics is provided within the greater context of the Efficient Market Hypothesis, followed by a discussion of how futures price can be integrated into models of exploration effort.

2.1 Models of Hydrocarbon Exploration Effort

Broadly speaking, three categories of models have been proposed to estimate the time path of oil and gas E&P. The classical geological models of Hubbert (1967), MacAvoy and Pindyck (1973), and more recently, of Reynolds (2002) rely on the basic premise that geological determinants drive the discovery process. More specifically, this school of modelers has focused on quantifying how the marginal product of exploration declines as reserve discoveries cumulate. As summarized by Black and LaFrance (1998), the common geological modeling framework assumes that, without the drilling of new wells, production from developed fields will fall off by a constant percentage over time, thereby following a pattern of exponential decline. As such, the annual rate of production can be defined as the first difference of a logistic curve, which traces a symmetric bell-shaped curve over a specific time horizon. Although Hubbert's original model gained popularity when it correctly forecast the peak of US oil production in 1970, Hubbert (1982) later went on to admit that the concept of the bell-shaped curve has neither theoretical nor geological foundation (Kaufmann and Cleveland, 2001).

Alternatively, a large body of theoretical and empirical literature stemming from the seminal work of Hotelling (1931), explicitly considers economic factors as impacting a firm's E&P decisions[4]. Within this framework, the hydrocarbon producer's economic problem is to maximize:

$$\int_0^T [p(t)q(t) - C(q(t), R(t))]e^{-rt} \tag{2.1}$$

subject to:

$$\int_0^T q(t)\,dt \le R_0, \tag{2.2}$$

$$\dot{R} = -q(t), \qquad R(0) = R_0 \tag{2.3}$$

$$q(t) \ge 0, \qquad \forall t \ge 0, \tag{2.4}$$

where p(t) denotes the market price of the hydrocarbon, q(t) denotes the quantity of the resource extracted, C(q(t), R(t)) denotes the cost function of hydrocarbon extraction, r is the real discount rate, R(t) denotes the current quantity of remaining reserves, and T denotes the final period of extraction. Additionally, it is assumed that the cost function increases in the current rate of extraction,

[4] see Farzin (1986), or Black and LaFrance (1998) for a discussion

$$\frac{\partial C(q(t), R(t))}{\partial q(t)} > 0, \tag{2.5}$$

decreases in the current stock of remaining reserves,

$$\frac{\partial C(q(t), R(t))}{\partial R(t)} < 0, \tag{2.6}$$

and is convex in q(t).

The first order conditions for an optimal extraction path are:

$$\frac{\partial H}{\partial q} = \left[p - \frac{\partial C(q,R)}{\partial q} \right] e^{-rt} - \lambda = 0 \tag{2.7}$$

$$\frac{\partial H}{\partial R} = \frac{\partial C(q,R)}{\partial R} e^{-rt} = \dot{\lambda} \tag{2.8}$$

$$\frac{\partial H}{\partial \lambda} = \dot{R} = -q, \qquad R(0) = R_0 \tag{2.9}$$

where λ, the difference between the price and marginal cost of production, represents the economic rent or scarcity rent to the producer. By further rearranging equations 2.7 – 2.9 it follows that, in an efficient market equilibrium, the scarcity rent for a nonrenewable resource will rise at the rate of discount (Hotelling, 1931). This axiom, is commonly referred to in the literature, as Hotelling's rule.

Testing the empirical validity, as well as investigating the implications of relaxing Hotelling's original assumptions, have become the subjects of an extensive literature (see *inter alia* Miller and Upton (1985), and Farzin (1986)). As established by Cleveland and Kaufmann (1991) however, both the purely physical and purely economic models suffer from the common flaw of model misspecification. Additionally, it has been shown that the purely economic models are prone to yielding paradoxical results in which price and production move in opposite directions (Kemp and Kasim, 2003). Thus, in an attempt to rectify the gap between physical and purely economic models, the integrationist approach to modeling hydrocarbon supply involves incorporating both geological and economic dynamics into the producer's maximization problem (Kemp and Kasim, 2003). Prominent among the integrationist modelers, Cleveland and Kaufmann (1991), Iledare (1995), Farzin (2001) and Kemp and Kasim (2003 and 2006), augment Hotelling's framework by including geological maturity, and technological change as determinants of exploration effort.

In the context of the current work, one of the most comprehensive empirical models of hydrocarbon exploration effort is that of Kemp and Kasim (2006). The authors introduce a practical methodology to model exploration effort in the United Kingdom Continental Shelf, but one general enough that it can be applied to any hydrocarbon resource. Kemp and Kasim's methodology is especially appealing for two reasons: first, they pioneer the inclusion of finding costs as a primary input in the exploration effort regression; and second, they devise a computationally straightforward method of modeling the interplay of geological, economic, and technological factors, as applied specifically to natural gas exploration.

Formally, the common integrationist approach involves incorporating the role of information and the opposing effects of depletion and technology on the time path of the discovery decline phenomenon. While there is some consensus on what constitutes an integrated model in the theoretical sense, substantial controversy surrounds both the appropriate analytical framework via which to model the process as well as the appropriate choice of explanatory variables. For example, while Pesaran (1990), Cleveland and Kaufmann (1997), Iledare (1995) and Forbes and Zampelli (2002) use cumulative drilling as an index for geological maturity, Farzin (2001), and Kunce (2003) apply cumulative reserve additions, and Reynolds (2002) uses the square of cumulative discoveries in a quadratic Hubbert trend specification. Similarly, while Iledare (1995), Farzin (2001) and Kemp and Kasim (2003) use a time trend to capture the impact of productivity-improving technological effects on production, ignoring the complication that the rate of technological change may be nonlinear; others, like Forbes and Zampelli (2000, 2002) create a technology index in an attempt to circumvent this problem.

Aside from choosing appropriate explanatory variables to capture technology and geological maturity, arguably, a more serious shortcoming of existing empirical integrationist models is their failure to clarify the difference between the exploration and production processes involved in the industry. This is surprising, given that this distinction has been well delineated in the theoretical literature. Building upon Hotelling's original model (equation 2.1), the importance of treating the drilling of new wells as a process distinct from that of producing from established reserves has been well recognized[5].

Conceptually, the dynamic differences between the two processes have been expounded by authors like Haller and Pavlopoulos (2006) who argue that while the initial

[5] See, *inter alia.* Attanasi, (1979), Pesaran (1990), Farzin (2001) or Kemp and Kasim (2003, 2006).

decision of whether to drill or not drill can be modeled as a binary, one time choice which hinges on expectations of future profits and is associated with the possibility of a sunk cost, the decision of how much to produce is more appropriately modeled as a dynamic optimization problem in continuous time made subsequent to the drilling decision.

Theorists, capture this distinction by modeling exploration as an intertemporal optimization problem. The model proposed by Farzin (2001):

$$\max_{\Delta R_t^*} \prod_t^e = P_t^e \Delta R_t^* - C\left(\Delta R_t^*,\ \sum_{\tau=0}^{t-1} \Delta R_\tau,\ z_\tau\right) \tag{2.10}$$

where $C(\Delta R_t^*)$ denotes the total cost of adding ΔR_t^* barrels of hydrocarbon to the existing proven reserves during period t; P_t^e denotes expected price for period t; $\sum_{\tau=0}^{t-1} \Delta R_\tau$ is the cumulative reserve additions up to period t and Z_t, is the index of the state of drilling technology at time t, is reflective of the common theoretical framework used to model hydrocarbon exploration effort.

A question of considerable interest is why theories of hydrocarbon exploration have only been partially corroborated by empirical evidence. In addition to the variation among choices of explanatory variables, this may be driven by the discrepancy regarding the formation of a meaningful price series for the purpose of applied study. A direct implication of the integrationist optimization problem (equation 2.10) is that agents form price *expectations* in formulating their drilling decisions. The most common application of this idea, has been to use current spot price as a proxy for expected commodity price[6]. Of course, implicit in this approach is the assumption that the exploratory firm forms static price expectations. Alternatively, Farzin (1986, 2001), Pesaran (1990) and Iledare (1995) assume that producers behave in accordance to the Adaptive Expectations Formation Hypothesis, and use a geometrical weighting of current and past prices as a measure of price expectations.

While several authors obtain adequate statistical support for applying adaptive price expectations in the case of petroleum (Farzin, 2001), it is important to note, that the alternative of a rational agent, has never been tested empirically. Moreover, no such concurrence can be deduced for the case of natural gas. Iledare (1995) finds a modest statistically significant effect, while Kemp and Kasim (2003) conclude that expected gas price (as proxied for by current spot price) has a negligible effect on natural gas exploration effort.

2.2 Futures Markets and the Efficient Market Hypothesis

There are two interrelated markets for petroleum and gas commodities: a cash, or spot market for immediate purchase and sale, and a storage market for inventories held by producers and consumers of the commodity. Because inventory holdings can change rapidly, spot price does not equate the production and consumption of the hydrocarbon-rather, additional information is contained in a hydrocarbon's futures price (Pindyck, 2004). Historically, it has further been argued that there are two fundamental social

[6] This is the approach taken by Forbes and Zampelli (2000, 2002), Kunce (2003), and Kemp and Kasim (200, 2006).

functions of commodity futures markets. First, they provide an organized forum which allows agents to undertake hedging or speculation, and second, the price of futures provides a unified view of agents' expectation with regard to future commodity price (Mazighi, 2003). Although there is a general consensus that futures markets transfer price risk, no other topic in finance has received as much controversy as that of futures markets' forecasting ability (Mazighi, 2003), or, in the language of the financial literature; of the *efficiency* of futures prices.

Originally defined by Fama (1970), the Efficient Market Hypothesis (EMH) has since been consented as one of the keystones of modern financial theory. As per Fama's definition, a market is efficient when the marginal profit of information is offset by the marginal cost and security prices fully reflect all available information to an agent at a given point in time. In the context of futures markets, this suggests that the arrival of new information be reflected in the movements of both forward and spot prices to the extent that futures prices today are the best, unbiased predictor of next period spot price (Mazighi, 2003). A direct implication of the EMH is that a rational agent will look to futures prices in formulating his expectations of future spot price.

Traditional analysis of the EMH proceeds by matching futures price at a contract's inception (*t-j*) with spot price at a contract's expiry (*t*) and then by testing the econometric specification developed by Fujihara and Mougoue (1997):

$$s_t = \beta_0 + \beta_1 f_{t-j} + u_t \qquad (2.11)$$

where s_t denotes the log of spot price at time t, f_{t-j} denotes the log of futures price of a contract with an expiry date of *j* at time *t-j* for delivery at time *t*, and u_t cannot contain any information, nor be serially correlated. To test this specification, the common methodology is first to run the regression by OLS then to test the joint restriction that $\beta_0 = 0$ and $\beta_1 = 1$ (Serletis and Scowcroft, 1991).

Although rarely addressed in the literature[7] one caveat about this traditional specification is that it actually tests two separate hypotheses within the broader context of market efficiency: that of long term unbiasedness and that of market efficiency as originally defined. McKenzie and Holt (2002) remind us that as per the original definition, market efficiency implies that futures prices will equal expected spot price plus or minus a constant, or possibly time-varying risk premium. On the other hand, futures prices will be *unbiased* predictors of spot prices only if no such risk premium exists. In this vein, three separate conclusions might be inferred from the rejection of the $\beta_0 = 0$ and $\beta_1 = 1$ null hypothesis: (1) the market may indeed be inefficient; (2) a constant risk premium exists that renders forecasts biased but possibly efficient; or (3) a time varying risk premium is inherent to the market, thus preventing futures prices from providing unbiased forecasts of future spot price. It is important to note that the second possibility- the existence of a constant risk premium- may be tested by running a supplementary test of $\beta_1 = 1$. Rejecting the joint hypothesis of $\beta_0 = 0$ and $\beta_1 = 1$ but

[7] Notable exceptions are the works of Serletis and Scowcroft(1991) and McKenzie and Holt (2002). Serletis and Scowcroftinvestigate and establish the presence of time-varying risk premia in the agricultural commodities market, McKenzie and Holt test the hypothesis that market efficiency implies that future market prices equal expected futures prices plus/minus a time premium, and develop a series of error correction models to account for the fact that this premium can be time varying.

failing to reject $\beta_1 = 1$ would imply market efficiency in conjunction with a constant risk premium. This, of course, renders the system biased.

Elam and Dixon (1988) discuss how traditional tests for market efficiency are dependent on the underlying time series properties of the data. If prices are nonstationary, they argue, then running a regression by OLS may yield biased results. McKenzie and Holt (2002) provide a thorough discussion on how previous research has attempted to circumvent this problem by estimating equation (2.11) in first difference form. This approach however will lead to misspecification if spot and futures prices are cointegrated (Woolridge, 2002).

Building upon traditional models, the more recent empirical literature has focused on the long-run properties of spot and futures prices in the context of cointegration. A central implication of the EMH is that even if the two series are non stationary, spot and futures prices do not drift apart (Hakkio and Rush, 1989). As such, a high degree of correlation between futures and corresponding future spot prices is a necessary condition for market efficiency. Originally developed by Engle and Granger (1987), the theory of cointegration can be used to analyze explicitly the relationship between such non-stationary time series. Put simply, cointegration implies a stationary long run relationship between two difference stationary time series. If the two series in question are futures price at a contract's inception and spot price at a contract's expiry, then finding the price series to be cointegrated can be interpreted as evidence of an efficient market. Although, to date, a number of alternative methods for testing market efficiency have been proposed (Kleit (2001)), two methods have become particularly routine for identifying long run cointegrating relationships: the Engle-Granger method, and Johansen's (1988, 1991) cointegration test.

Serletis and Scowcroft (1991) provide a straightforward mathematical representation of the concept of cointegration. Assuming that both spot prices and futures price are first difference stationary, equation (2.11) can be re-written as:

$$s_t - \beta_0 - \beta_1 f_{t-j} = u_t \tag{2.12}$$

to show that for a linear combination of the non-stationary variables in their level form, the residual, (u_t) will generally also be non-stationary. If, however u_t obeys stationarity, then s_t and f_{t-j} are cointegrated. To test this formally, the authors employ the Engle-Granger method, which involves application of OLS to estimate equation (2.12), and subsequently tests for a unit root in the regression residual. Their test provides strong evidence for the case of market efficiency in the agricultural commodities market.

The other routine econometric approach for testing cointegration is conducted using the maximum likelihood trace test estimation method, developed by Johansen (1988, 1991)[8] and refined by Johansen and Juselius (1990). As described by Serletis (1994), one of the drawbacks of the Engle-Granger approach is that it does not distinguish between the existence of one or more cointegrating vectors. Based on maximum likelihood estimates of a cointegrating regression, the Johansen method provides a powerful test for evading this problem. Following Panagiotidis and Rutledge (2007), after two series are determined to be first difference stationary (or, in the

[8] For the purpose of this thesis, I will only review the operational details of this test. For a full theoretical overview, the reader is referred to Johansen (1991).

language of Engle and Granger, I(1)), in order to carry out the Johansen cointegration test one begins by formulating a p-dimensional Vector Error Correction Model (VECM):

$$\Delta y_t = \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + \Pi y_{t-1} + \mu + \varepsilon_t \tag{2.13}$$

where y_t is a matrix of difference stationary variables (in this case $y_t = (s_t, f_{t-j})$), k is the number of lags, μ is a drift parameter, $\prod$ is a $(p \times p)$ matrix of the form $\prod = \alpha\beta'$, α and β are $(p \times r)$ matrices of full rank, and β contains r cointegrating vectors. Johansen's method investigates whether the coefficient matrix contains any information about long-run associations among the variables of the system. That is, the null hypothesis that there are at most r $(0 \leq r \leq p)$ cointegrating vectors is tested using the likelihood ratio test statistic:

$$TRACE\ TEST = -T \sum_{i=r+1}^{M} \ln\left[1-\left(r_i^*\right)^2\right] \tag{2.14}$$

Rejection of the null hypothesis of no cointegrating vector (r = 0), and failing to reject the hypothesis of one cointegrating vector (r = 1) leads one to conclude that the two difference stationary variables in question, are cointegrated.

The literature examining market efficiency is fairly extensive. Due to the fact that the natural gas futures market is quite young however, there are few works which focus explicitly on efficiency, and, to my knowledge, none that investigate separately the hypotheses of strict market efficiency and unbiasedness in the natural gas market. Among existing works, the methodologies employed have been vastly different. Unsurprisingly thus, conclusions have been diverse. For instance, while Walls' (1995) cointegration analysis provides evidence for efficiency in the natural gas market, the Engle-Granger cointegration test performed by Root (1998) lends support to the hypothesis in the case of the two month futures contract but rejects it for the three month contract. In a similar vein, Herbert (1993) specifies and tests both a simple linear relationship between spot and futures prices and a cointegration specification to conclude that the natural gas futures market was inefficient during its first several years of operation. Chinn et al. (2005) focus on short term dynamics and provide evidence supporting the EMH for six and 12 month contracts but not for the 3 month horizon. Finally, Mazighi (2003) assesses both the efficiency and the relative forecasting power of futures prices, to conclude that while there is statistical co-movement between futures and corresponding spot prices, forward price is not a relatively optimal predictor of future spot price.

Although several of the aforementioned studies conduct empirical tests on contracts of various expiry length, the effect of term length on market efficiency is never really discussed. Appropriately, understanding the impact of futures contract maturity length on market efficiency requires an examination of the literature beyond the domain of the hydrocarbon market[9]. By definition, the risk premium inherent in a biased market represents the compensation required by agents to hold long term positions in a commodity. As expounded by Inci and Lu (2005), there are two key reasons that risk premium becomes an increasingly important component of the futures-spot price relationship, as the maturity of futures contracts increases. First, hedging activity in futures tends to concentrate on longer-maturity contracts so that the pricing of these

[9] The reader is referred specifically to the work of Inci and Lu (2005) who provide a thorough theoretical overview and model the effect of contract maturity on risk premium.

longer term contracts is affected by the risk premium to a much greater degree than the pricing of the short term contracts. Second, by virtue of covered interest parity, the difference (basis) between futures and spot prices is equivalent to the differential of the interest rates of the same maturity. That is, the shorter end of the interest rate term structure, generally set by the central banks, is not affected by the market risk premium to the same extent as is the interest rate term structure further along the yield curve. This means, that risk premium should not impact the basis if the maturity of the contract is sufficiently short.

2.3 The Informational Content of Natural Gas Futures Prices

If theory suggests that a rational agent utilizing all available, relevant information looks to the futures market in formulating expectations of future spot price, then it must follow, that futures prices reflect any information which is in fact relevant to the pricing of natural gas. The question then arises: which variables are predicted to have a significant explanatory effect on natural gas prices? As conjectured by Bachmeir and Griffin (2006), a likely candidate would be the price of a potentially substitutable fossil fuel.

The existence of shared stochastic trends between oil and gas prices has been investigated in a number of studies[10]. The intuition behind the proposed relationship is driven off of the notion that for many years, natural gas and refined petroleum products existed as close substitutes in the US industrial and electric power generating sectors. Supporting this conjecture, the early cointegration studies of Yucel and Guo (1994) and

[10] See, for example Yucel and Guo (1994), Serletis and Herbert (1999), Serletis and Rangel-Ruiz (2004), Ghouri (2006), or Brown and Yucel (2007).

Serletis and Hubert (1999) identified significant shared trends between natural gas and oil prices. As diarized by Brown and Yucel (2007) however, the last decade has seen the number of facilities capable of "fuel-switching" decline substantially. Not surprisingly therefore, studies utilizing a more recent dataset have generally reported a weakening, or disintegration of the cointegration relationship[11].

In the context of futures markets, the existence of cointegrated oil and gas futures prices becomes even more plausible when one considers that several industry rules of thumb have long served to relate natural gas prices to those of oil by using constant ratios, or energy equivalencies at the burner tip[12]. In formal test of this hypothesis, Brown and Yucel (2007) apply a VECM to uncover a significant relationship between oil and natural gas prices, only if conditioned by exogenous factors such as weather, seasonality and natural gas storage and after accounting for episodes of shut-in production. As such, their analysis dispels the notion that the standard industry pricing rules often applied in forecasting natural gas prices can adequately explain past differential movements in oil and natural gas prices. Given the difficulty of forecasting each of these exogenous

[11] Recent empirical studies which examine the co-movement of oil and gas prices fail are fairly divided as to whether or not to support the hypothesis of cointegration. For example, Serletis and Rangel-Ruiz (2004) utilize a bounds testing approach to reject the null hypothesis of common and codependent cycles for the 1991-2001 series of West Texas Intermediate (WTI) oil and Henry Hub (HH) gas prices. Similarly, the ECM developed by Bachmeier and Griffin (2006) qualifies the degree of cointegration between two 1991-2004 oil and natural gas prices as relatively weak. Conversely, Ghouri (2006) applies the Johansen and Juselius cointegration technique to establish a strong correlation between crude oil and natural gas prices in each of a North American, European and Asian Pacific market.

[12] Brown and Yucel (2007) examine the performance of three standard rules of thumb for natural gas pricing:

(i) the simple rule of thumb, under which the price of natural gas is assumed to be one-tenth the price of crude oil.

(ii) the energy content rule, which states that the price of one million British thermal units (MMBtu) of natural gas ought to equal one sixth that of a barrel of oil in order to equate the energy equivalencies of the two hydrocarbons.

(iii) the Burner-Tip Parity rule, under which natural gas price adjusts so that gas pricing yields parity with residual fuel oil at the burner tip.

variables going forward, a question of considerable interest relates to the strength of the relationship between expected future natural gas spot prices, as proxied by natural gas futures prices, and expected future oil spot prices- as proxied by oil futures prices.

Using an identical methodology as that discussed in the preceding subsection, it has become customary to investigate the long run cointegrating relationship between crude oil and natural gas prices by examining the following relationship:

$$P_{1,t} = \alpha_0 - \alpha_1 P_{2,t} \tag{2.15}$$

(where $P_{1,t}$ denotes the price of the first, and $P_{2,t}$, the price of the second time series in question at time t), in order to determine whether the implicit error in equation (2.15) obeys stationarity.

As pointed out by Bachmeir and Griffin (2006) however, a major limitation of this approach stems from the fact that such a test focuses exclusively on the existence of long run relationship between two price series, entirely omitting the economically more interesting question of the *degree* of cointegration within such a system. Offering a remedy to this potentially serious shortcoming, Bachmeir and Griffin advocate applying a basic ECM, arguing that it embodies cointegration analysis by providing a test for the existence of a long run cointegration relationship between the two data series, while, at the same time yielding readily-interpretable summary statistics on the degree of market integration within the system.

To briefly describe the Bachmeir and Griffin approach, consider first the original ECM model proposed by Engle and Granger (1987):

$$\Delta P_{1t} = \Phi_0 \Delta P_{2t} - \theta\left(P_{1,t-1} - \alpha_0 - \alpha_1 P_{2,t-1}\right) + \varepsilon_t \tag{2.16}$$

Notice that this equation involves both a contemporaneous price change term as well as an error correction term, so that deviations from the long run cointegrating relationship, $(P_{1,t-1} - \alpha_0 - \alpha_1 P_{2,t-1})$ force the price adjustment back to the long run cointegrating relationship at a speed of adjustment of θ. Stated simply, θ measures the speed of adjustment to a long term cointegrating relationship, and Φ_0 corresponds to the contemporaneous price response. It is convenient to think of Φ_0 as an indicator of the short-run relationship between the two prices.

Bachmeir and Griffin compute two additional summary statistics when characterizing the degree of market integration in their model. The first, defined by the authors as "instant %" is described by the following progression: assuming that the long run effect of a one unit increase in P_2 is an increase of α_1 in P_1, the fraction of that long run increase realized instantaneously is simply Φ_0 divided by α_1:

$$\text{instant } \% = \Phi_0 / \alpha_1 \tag{2.17}$$

Likewise, any disequilibrium not captured instantly adjusts exponentially at a rate of θ. Thus, the "half-life" of this adjustment process is:

$$\text{half-life} = \ln(0.5) / \theta \tag{2.18}$$

A high instant %, coupled with a short half-life suggests that two price series are highly correlated.

Chapter 3

A Model of Natural Gas Exploration Effort

Building upon the contributions of previous studies, in this chapter I develop, test and analyze an econometric model which characterizes the relationship between natural gas exploration effort, geological and economic factors. Contingent on the EMH, I predict that futures prices have superior explanatory power to spot prices within the exploration effort supply equation. To my knowledge, this is the first work to incorporate futures market dynamics into such a framework.

3.1 Empirical Methods

In the spirit of Farzin (2001), it is assumed that the typical natural gas explorationist firm in the WCSB is a price taker, and that P^e denotes price expectation at time *t*. In each period, the firm decides on the rate of exploration effort to exploit so as to maximize expected profits in the subsequent period. This is specified by the following equation:

$$\Pi^e = P_t^e R_t^e \left(\Omega_t, M_t, d \right) - C_t \tag{3.1}$$

where P^e_t denotes expectations held at time *t* of natural gas price at time *t+x,* R^e_t denotes the quantity of natural gas expected to be added to a firm's reserves by exerting one unit of exploration effort, Ω_t can be seen as the contemporaneous probability of success for a unit of exploratory effort, M_t denotes the geological maturity of the basin in which exploration is taking place, d denotes the depth of drilling and C_t, the cost of drilling at time *t.* Additionally, firms are assumed to be price takers, and national markets to supply capital.

Empirical investigation of equation (3.1) is based on the methodology developed by Kemp and Kasim (2006), in which the level of well startups in a given region is determined by the interplay of economic, geological and technological factors. In order to fully exploit the drilling depth specific properties of my data set, a fixed effects (FE) panel design model is used as the basic tool for this analysis. The use of panel data techniques diminishes omitted variable bias, and, as such diminishes the effects of model misspecification.

Assuming that first differencing is required to fulfill stationarity conditions, for a specific drilling depth category *i,* supply of natural gas exploration effort is given by:

$$\Delta R_{it} = \beta_0 + \beta_1 \Delta P_{it} + \beta_2 \Delta F_{it} + \beta_3 \Delta C_{it} + \beta_4 CD_{it} + \beta_5 TI_{it} + a_i + u_{it} \qquad (3.2)$$

where Δ is the first difference operator, R_{it} denotes the total number of natural gas rigs in the entire WCSB fleet at time t within the i^{th} drilling depth category, P_{it} denotes natural gas spot price at time *t*, F_{it} gives the price of a natural gas futures contract at time *t* for the delivery of natural gas at time t+*x*, C_{it} denotes finding and development cost for natural gas, CD_{it} denotes cumulative drilling having taken place at time *t,* TI_{it} denotes the state of efficiency-improving technology, β are the parameters to be estimated, a_i is the unobserved drilling depth effect, and u_{it}, the normally distributed error term.

My model is innovative in two important ways. First, it embeds WCSB panel data for various drilling depth categories into an empirical model of exploration effort, allowing me to control for the fact that risk profiles vary significantly with drilling depths[13]. Second, conditional on the EMH, and assuming that firms behave as rational agents, the model includes futures prices as a determinant of exploratory effort.

The primary hypothesis is that futures prices will have superior explanatory power to spot prices in the determination of exploration effort. Additionally, it is expected that geological maturity and land costs will have a negative effect, and technological improvements, a positive effect on the level of exploration drilling.

It well known that applying conventional econometric techniques to an integrated time series can give rise to misleading results, therefore verifying stationarity properties of equation (3.2) is required before I can proceed to examine the econometric properties of my model. To this end, two general approaches are used. As has become customary within the literature, the first approach utilizes both the Augmented Dickey Fuller (ADF)[14] (Dickey and Fuller, 1981) and Phillips-Perron (Perron, 1988) tests[15]. The second approach involves application of a set of unit root tests specific to a panel design.

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[13] Forbes and Zampelli (2002) present an overview of the dynamic relationship between drilling depth and success rate to conclude that the relationship may not necessarily be monotonic; offsetting the fact that shallow hydrocarbon deposits are more easily discovered than deeper deposits, the authors point to the fact that shallower deposits are also depleted more quickly.

[14] One of the major shortcomings of the ADF test is that it does not allow for autocorrelated residuals in its model specification. As such it has become customary within the literature to complement the ADF test with tests which are robust to serial correlation, such as the test of Phillips and Perron (1988). Following Serletis and Scowcroft (1991) and Panagiotidis and Rutledge (2006), I conduct both tests to see whether there is discrepancy between the results.

[15] The reader is referred to Serletis and Scowcroft (1991) for both a detailed mathematical representation and a discussion of the relative advantages and shortcomings of the Phillips-Perron test.

The basis of each of the stationarity tests employed in this thesis can be traced to the original works of Dickey and Fuller (1979, 1981), who identify unit roots by estimating one of two models:

$$\Delta y_t = \mu + \gamma y_{t-1} + \varepsilon_t \tag{3.3}$$

$$\Delta y_t = \mu + \beta t + \gamma y_{t-1} + \varepsilon_t \tag{3.4}$$

and testing the significance of γ in equation (3.3), or the joint significance of $\gamma = \beta = 0$ in equation (3.4). As summarized by Halkos and Kevork, (2005), the ADF test employs the same general methodology but makes parametric corrections for higher order correlation by adding lagged variables into equations (3.3) and (3.4). The Phillips-Perron test adds the non-parametric correction for serial correlation developed by Newey and West (1987) into the above equations.

Starting from the seminal works of Quah (1994), and Levin *et al.* (2002) a variety of tests have been advanced which introduce the unit root test into panel data (see Gutierrez, 2006 for a discussion). The primary motivation behind the application of a panel data-specific unit root test, as opposed to a standard univariate root test is to exploit the extra information provided by pooled cross-section time series data, thereby increasing the power of the test (Konya, 2004). Although several newly-proposed panel unit root tests have appeared in the literature over the last few years, this paper will employ two that have been particularly well-documented[16]: those of Im *et al.* (1997) (the IPS test), and Maddala and Wu (1999) (the MU test). For the purpose of this thesis, I provide a brief summary of the ideas behind both of the test specifications. For a full mathematical representation, the reader is referred to Caporale and Cerrato (2006).

Im et al. (1997) propose a test based on the separate Dickey Fuller unit root tests of each of N cross-sectional units in a panel data set (Halkos and Kevrok, 2005). Their methodology involves estimating a t-test for unit roots in heterogeneous panels, where they show that the average of the t-statistics is normally distributed with mean μ and variance σ^2. Based on the mean of the individual Dickey Fuller t-statistics of each unit in the panel, the IPS test assumes that all series are non-stationary under the null hypothesis.

Similarly, Maddala and Wu's (1999) test is based on *p-values* of the Dickey Fuller unit root test for each of the N cross-sectional units in a panel data set (Halkos and Kevrok, 2005). The null hypothesis assumes non-stationarity against the alternative that at least one series in the panel is stationary. The sum of significance levels P_i is distributed as χ^2 with 2N degrees of freedom.

The results of the panel data unit root tests, reported in Tables 3.1 and 3.2 are presented in a similar format to that of Caporale and Cerrato (2006) who use the IPS and MU tests to assess stationarity of real exchange rate data. Specifically, Table 3.1 reports the marginal significance levels (p-values) of the individual ADF and Phillips-Perron tests, whereas the results of the multivariate panel unit root tests are displayed in Table 3.2

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[16] Konya, (2004), Banerjee, (1999), and Caporale and Cerrato (2006) each provide a discussion on the applicability and merits of these particular tests.

Technically speaking, the model defined by equation (3.2) can be estimated by application of either fixed effects (FE), or random e ffects (RE) techniques. Although estimation by RE will generally yield a more efficient estimator, theory suggests that using RE is only appropriate if the unobserved effect is uncorrelated with all of the explanatory variables (Woolridge, 2002). In the case of equation (3.2), it is hypothesized that a_i is correlated with both spot price and futures price, and that the unobserved drilling depth effects are significant. As such, I should be principally concerned with the FE results. To test this hypothesis formally, I employ the generally favored Hausman test. Under the Hausman null hypothesis of uncorrelated heterogeneity, the RE estimator is consistent and efficient and FE is inefficient and consistent; under the alternative of correlated heterogeneity, RE is inconsistent and FE is both consistent and efficient (Woolridge, 2002). Accordingly, rejecting the null hypothesis would suggest that FE should be used.

3.2. Data

My data set allows me to examine the monthly relationship between the number of exploratory rigs in the WCSB and natural gas spot and futures prices, taking into account the influence of costs, technological improvements and geological maturity on exploration effort.

3.2.1 Rig Count Data

The geoSCOUT$_{TM}$ software package developed by geoLOGIC systems tracks the total rig count and rig utilization rate for the WCSB on a weekly basis from January 1997, onwards. I will be using data from January 1998 to April 2007. This data is further broken down by drilling depth category. As per common industry guidelines, a shallow rig is one drilled between 0 and 1200 meters below the ground, a medium rig is 1200 – 2800 meters deep, and a deep rig, 2800 – 10000 meters deep. As my goal is to account for the rig depth-specific properties of the given dataset, my panels will correspond to these standard categories.

In consideration of the fact that this thesis is primarily concerned with investigating exploratory rig activity in the basin, using total rig fleet data is preferred to using active rig count. While it may be argued that this method may not provide an explicit measure of the number of exploratory rigs due to the fact that total rig fleet includes rigs of both the exploratory and producing type, it may be acceptable to the extent that on average, new gas wells in the WCSB have exhibited fairly constant decline rate profiles over their lifetimes over the last decade (NEB, 2007).

A graph of total WCSB natural gas rig fleet, broken down by depth category, is shown in Figure 3.1.

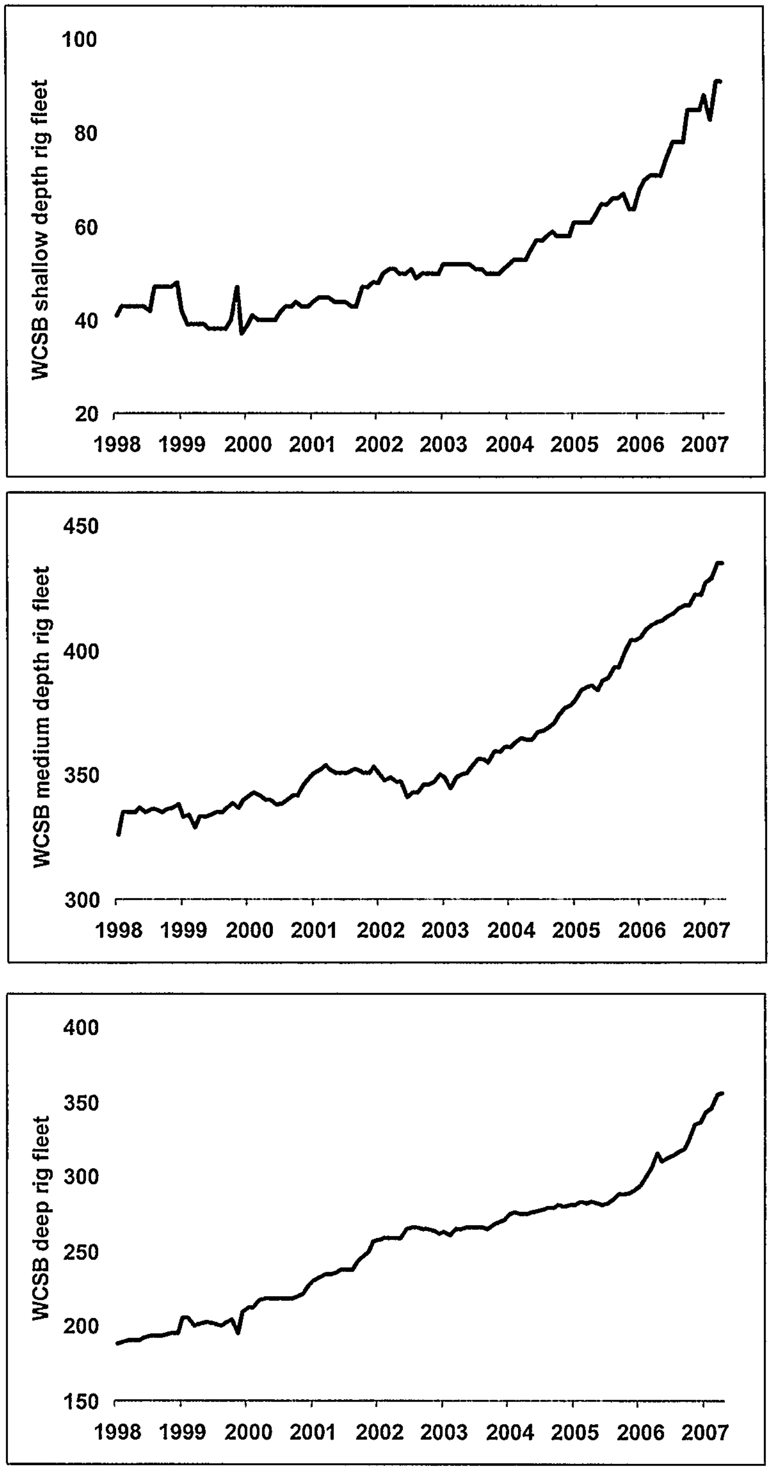

Figure 3.1: Total Natural Gas Rig Fleet in the WCSB by Drilling Depth Category

3.2.2 Price Data

In North America, natural gas is traded on a daily spot market as well as on a futures market on the New York Mercantile Exchange (NYMEX). The price of the commodity is set by markets at various hubs in North America, of which the Henry Hub, located in Louisiana is considered the benchmark (EIA, 2006) The NYMEX natural gas futures contract guarantees delivery of a standard one MMBtu of natural gas to the Henry Hub at a future point in time between one and 36 months from the day of issue of the contract. Futures contracts are often referred to by their specific delivery months; otherwise known as their "expiries".

In the present study I use daily spot and futures price data covering the period of January 1, 1998 to April 30, 2007 as reported by Bloomberg Information Systems. The spot price series is the average Henry Hub natural gas price for a given month, and the futures price series is the monthly average of the average daily prices of 25 to 36 month NYMEX-traded contracts. That is, to obtain the average futures price which corresponds with January, first I obtain the average price of the 25 to 36 month contracts for each day in January and then take the average of these averages. The average 25 to 36 month horizon was selected specifically to reflect a typical timeframe between the drilling of an exploratory well and first, steady production.

3.2.3 Cumulative Drilling Data

Kemp and Kasim (2006) argue that geological maturity effects for hydrocarbon drilling are best proxied for by cumulative production within a specific region. The Canadian Association of Petroleum Producers (CAPP) reports annual natural gas production for the

WCSB since the inception of the industry, and monthly Gross New Production for each natural gas-producing Canadian province from January 1997. As such, I compiled a cumulative drilling series for each month from January 1998 to April 2007 by sequentially adding monthly gross new production in the WCSB to the 1997 year end annual cumulative drilling number.

3.2.4 Cost Data

Ideally, equation (3.2) would be estimated using total monthly exploration expenditure data for natural gas drillers in the WCSB. Unfortunately, such data is unavailable. Although various agencies track full cycle finding and development costs, the problem with these numbers is that they are reported on an annual basis. Although it could be argued that interpolating the missing monthly values would provide a reasonable approximation of costs for WCSB drillers, in the event that first differencing is required to carry out the current analysis, the interpolated values would be meaningless in econometric analysis. It was therefore necessary to develop a proxy for costs, for which monthly data is available.

One of the key components comprising exploration cost is the cost of land; a price series tracked by the Government of Alberta on a monthly basis. In light of the fact that over 80% of WCSB natural gas drilling activity occurs in Alberta (NEB, 2007), the time series of average natural gas land sale prices in Alberta as taken from the Alberta Government Department of Energy, will be used in this analysis.

3.2.5 Horizontal Drilling Data

Horizontal drilling has become one of the most valuable technologies ever introduced into the upstream natural gas drilling business. Unlike traditional (vertical) wells which are drilled vertically their entire length, horizontal wells are drilled first vertically, then make a right angle turn to reach the larger part of a reservoir. As discussed by Woiceshyn and Daellenback, (2005) the often-mentioned benefits of horizontal drilling include accelerated production, increased recoveries and associated significant improvements in operator cash flow.

Since horizontal drilling began in Canada in the mid 1990's, the number of horizontally drilled wells in the WCSB has risen dramatically, steadily displacing vertically-drilled natural gas plays (Stell, 2007). Furthermore, though they are still more expensive to drill than a vertical well, the last decade has seen a precipitous decline in the price of a horizontal well (Stell, 2007). If the goal then, is to incorporate a measure of technological improvement into the current regression equation, it is easy to argue that horizontally-drilled well count as a percentage of total well count provides a reasonable proxy of technological improvement in the basin. Here, I employ this data series as a technological index.

Ideally, monthly horizontal drilling percentage in the WCSB would be used to develop a technological index. However, such data is unavailable. Instead, I use the percentage of wells in the US that are horizontally drilled as taken from the Baker Hughes website. Using the US number may be appropriate to the extent that in the hydrocarbon industry, technological improvements diffuse very quickly; especially across the Canadian-US border. As such, it is expected that trends in US horizontal drilling are similar enough as to provide a reasonable proxy for technological improvements in Canada.

Baker Hughes provides the worldwide oil and natural gas industry products and services for drilling, formation evaluation, completion and production. Their US rig count survey is conducted on a weekly basis and breaks down the number of active rigs by drilling type. For the purpose of the current study, the weekly numbers from January 1998 to April 2007 were averaged by month.

3.3 Results

3.3.1 Stationarity

Four tests were used to examine the stationarity properties of the rig count, spot price, futures price and land cost time series. As a first step, individual ADF and Phillips-Perron tests were conducted. The number of lags in the ADF regression was taken to be the order selected by the Akaike Information Criterion (AIC) plus 2, as suggested by Pantula *et al.* (1994) and utilized by Serletis and Rangel-Ruiz (2004)[17]. The marginal significance levels of the ADF and Phillips-Perron tests, as well as the optimally chosen lag length are reported in Table 3.1.

Based on the p-values for the ADF test, the null hypothesis of a unit root in levels cannot be rejected for any of the time series examined at the 10% significance level. The null hypothesis of a unit root in first differences is rejected at the 5% significance level in each case. With the exception of the Alberta land costs, these results were replicated

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[17] See Pantula *et al.* (1994) for a discussion of the advantages of using this rule for choosing the optimal number of augmenting lags.

exactly by application of the Phillips-Perron test, suggesting that the series are first difference stationary. This finding is consistent with the Nelson and Plosser (1982) argument that most macroeconomic and financial times series have a stochastic trend. In the case of Alberta land costs -which are first difference stationary according to the ADF test and stationary in levels according to the Phillips-Perron test- it was necessary to make a judgment as to whether or not first differencing will be applied. For the sake of consistency, it was decided to first difference all series before further analysis was pursued.

As previously discussed, application of the ADF and Phillips-Perron tests to panel data has very low power against the null of a unit root (Capporale and Cerrato, 2006). Addressing this problem, the panel-specific unit root tests were also carried out on the pooled total rig fleet data. Results are presented in Table 3.2. Based on corresponding p-values, the t-bar test cannot reject the unit root null hypothesis for data in level form, and strongly rejects the null hypothesis when the data is differenced. This result is confirmed exactly by the MU test statistic.

Overall, the results obtained from the ADF, Phillips-Perron and panel unit root tests suggest that all elements within my data set are first difference stationary. As such, the remaining analyses in this thesis will be carried out using the first differences of each data series.

Table 3.1
Marginal Significance of ADF and Phillips-Perron Unit Root Tests

Series	Lag	Levels		First Differences	
		ADF	PP	ADF	PP
shallow rigs	5	0.999	0.999	0.016	0.000
medium rigs	3	0.999	0.999	0.011	0.000
deep rigs	3	0.992	0.995	0.000	0.000
Henry Hub spot price	5	0.336	0.115	0.000	0.000
25 - 36 month Futures pric	4	0.858	0.928	0.045	0.000
Alberta land costs	5	0.391	0.034	0.000	0.000

Sample period, monthly data: 01-1997 to 04-2007

Table 3.2
Panel Unit Root Tests of WCSB Rig Fleet

	IPS test			MU test	
	Levels	First Difference		Levels	First Difference
Test statistic:			Test statistic:		
t-bar	2.266	0.9989	χ^2	-3.392	0.0112
p-value	0.802	0.9917	p-value	-4.358	0.0004

Sample period, monthly data: 01-1997 to 04-2007

3.3.2 Hausman Test

Given that there is no reason to believe that the unobserved depth category effects are uncorrelated with all of the explanatory variables, I should be principally concerned with the results of the FE regression. The Hausman test, for which results are presented in Table 3.3 was employed to formally test this assumption. Based on the corresponding p-value of 1.000, the null hypothesis that the RE estimator is efficient and consistent while the FE is inefficient, is strongly rejected in favor of the alternative that RE is inconsistent and that FE is both consistent and efficient. Accordingly, the FE methodology will be adopted in estimating equation (3.2).

Table 3.3

Hausman Test for the Appropriateness of Using Fixed versus Random Effects

Test statistic	
χ^2	0.000
p-value	1.000

The testing specifications are as follows:

H_0: RE estimator is consistent and efficient; FE estimator is inefficient and consistent

H_A: RE estimator is inconsistent; FE estimator is efficient and consistent

3.3.3 A Fixed Effects Model of Exploration Effort

After differencing each data series, the FE regression of equation (3.2) was estimated for a full panel data set. The estimates of the parameters ($\beta_0, \beta_1, \beta_2, \beta_3, \beta_4, \beta_5$) and key statistics are reported in Table 3.4. For the purpose of comparison, I have estimated six models, (a) through (f). Each model includes cumulative production as a proxy for geological maturity of the WCSB, and average Alberta land sale prices. The distinction lies in the fact that Models (a) through (c) include the technology proxy, while Models (d) through (f) do not. Further, Models (a) and (d) only include spot prices (ΔP_{it}) in the regression equation; models (b) and (e) only include futures prices (ΔF_{it}), and Models (c) and (f) include both price series. Comparison of the regression results of these models can be used for evidence regarding the relative explanatory power of futures and spot prices in the exploration effort supply equation.

In Models (d) through (f), the estimated coefficient on cumulative production is significant below the 1% level, implying that geological maturity has a positive, robust effect on exploration effort. Interestingly, when the technology proxy is added into the regression in models (a) through (c), the statistical significance of geological maturity disappears and the sign on the estimated coefficient becomes negative, as per *a priori* expectations. While at first glance, the instability of these coefficients would appear to suggest that the model may not be able to differentiate adequately between the explanatory effects of technological change and geological maturity, it may be useful to draw an additional insight from this result. Notably, the reversal of the signs on the coefficient highlights the importance of including both the effects of geological depletion, and technological effects into such a framework in order to avoid generating inconsistent findings due to misspecification error. This is consistent with the findings of Kemp and Kasim (2006).[18]

In models (a) through (c), the positive and statistically robust coefficients on technology support the hypothesis that technological improvements have a significant, positive bearing on exploration effort. Owing to the fact that US, and not WCSB data was utilized, one should be cautious in assigning any quantitative significance to these numbers. More importantly, this result provides evidence regarding the importance of incorporating an actual technological measure rather than a simple linear time trend, to proxy technological improvements. The coefficient on Alberta land cost had the correct *a priori* negative sign, however with a corresponding p-value ranging from 0.122 in Model (e), to 0.299 in Model (a), the statistical significance of this dependent variable, is questionable.

Of particular interest is the impact of price on exploration effort. The conclusions offered by the panel estimates lend support to my central hypothesis pertaining to the superior explanatory power of futures prices, over spot prices in the exploration effort supply equation. Irregardless of the presence of the technological proxy, and in line with the conclusions drawn by Pesaran (1990) both Models (a) and (d) show that spot price has a negative and statistically insignificant effect (the associated p-values are 0.33 and 0.28, respectively) on exploratory effort. Conversely, in concordance with the common perception among industry analysts, the influence of futures price is not only correct (positive), it is also statistically well determined (always below the 4% significant level). It is important to recognize that when both spot and futures prices were included in the

[18] Kemp and Kasim (2006) provide a thorough discussion of the merits of modeling separately the effects of depletion, economics and technology on exploration effort.

regression equation in Models (c) and (f), these results did not change. That is, the effect of futures prices on exploration effort continued to be positive and well determined, while the effect of spot prices was both negative and insignificant.

In short, my findings support the maintained hypothesis that exploration effort in the WCSB falls as costs increase, rises as drilling technology improves, and that natural gas futures prices have superior explanatory power to spot prices within the supply equation examined. The underlying implication of this result is that agents behave rationally, in that they acknowledge futures prices' predictability of future spot prices, as postulated by the EMH. The subsequent chapter offers a more formal look at this idea.

Table 3.4

Fixed Effects Estimates of WCSB Natural Gas Exploration Effort (equation 3.2)

Variable	Model (a)		Model (b)		Model (c)		Model (d)		Model (e)		Model (f)	
	coefficient	p-value	coefficient	p-value	coefficient	p-value	coefficient	p-value	coefficient	p-value	coefficient	p-value
D.Futures price			1.071	0.018	1.173	0.010			0.944	0.036	1.052	0.021
D.spot price	-0.059	0.329			-0.084	0.165	-0.065	0.282			-0.088	0.148
D.land cost	-0.001	0.299	-0.002	0.149	-0.002	0.156	-0.001	0.242	-0.002	0.122	-0.002	0.128
cumulative production	-0.107	0.471	-0.105	0.319	-0.015	0.322	0.308	0.000	0.030	0.000	0.030	0.000
horizontal rig %	18.811	0.004	20.301	0.002	20.185	0.002						
constant	0.931	0.615	1.375	0.456	1.366	0.459	-3.944	0.001	-3.851	0.001	-3.835	0.001
ρ	0.046		0.047		0.047		0.048		0.049		0.049	

Sample period, monthly data: 01-1997 to 04-2007

Chapter 4

The Efficient Market Hypothesis and Natural Gas Futures Markets

The examination of the behavior of natural gas futures markets has been undertaken by several authors. Most often however, studies lack strong statistical support. Moreover, to the best of my knowledge, the two hypotheses of market efficiency and unbiasedness have never been studied separately for the natural gas market. As such, a proper investigation of the EMH for this market is warranted. For the sake of completeness, in this section I utilize three model frameworks and two econometric techniques to investigate market efficiency and unbiasedness for both near month and long term natural gas futures contracts.

4.1 Data

Similar to Chapter 3, I obtain closing day Henry Hub composite spot prices and natural gas NYMEX futures prices for two, three, four and 36 month contracts, from Bloomberg Information Systems. Varying my procedure slightly from that of the previous chapter, although daily data is available, I employ monthly data to avoid problems associated with infrequent trading of contracts with specific expiries (Root, 1998). That is, each monthly price is taken as the closing price of the last business day of each month, for both spot and futures prices for the period, January, 1998 to February 2007.

4.2 Empirical Methods and Results

4.2.1 A Standard Test for Market Efficiency

Following the original specification developed by Fujihara and Mougoue (1997), I begin by matching the log of futures price at the contract's inception date (F_t), for a contract with a pre-determined expiry date of x, with the log of spot price at the contact's expiry date (P_{t+x}), and subsequently employ OLS to regress P_{t+x} on F_t as in the following equation:

$$P_{t+x} = \hat{\beta}_0 + \hat{\beta}_1 F_t + u_t \tag{4.1}$$

Next, in an attempt to capture empirically the two separate questions described, the joint null hypotheses of strict[19] market efficiency ($\beta_1 = 1$), and unbiasedness ($\beta_0 = 0$ and $\beta_1 = 1$) are respectively tested for, using the standard t-test and F-test specifications. Table 4.1 displays the estimated coefficients and the p-values of the regression of equation (4.1), as well as of the tests of both null hypotheses for the four cases of x = 2, 3, 4 and 36 months.

Based on the p-values of the OLS regression, several key conclusions can be drawn. First, the joint hypothesis of $\beta_0 = 0$ and $\beta_1 = 1$ cannot be rejected for the case of the two and three month futures contracts ($p = 0.147$ and $p = 0.065$, respectively) providing evidence that short term futures prices are unbiased predictors of future spot price. Of course, unbiasedness is a sufficient condition for market efficiency. As such, my results

[19] "Strict" market efficiency will always refer to the case where $\beta_1 = 1$. It is worthwhile to note that strict market efficiency is a necessary condition for unbiasedness, whereas unbiasedness is not required for strict market efficiency to hold.

suggest that in the absence of time varying risk premia, two and three month futures contracts are both unbiased and efficient predictors of future spot price. It is interesting to note that this result in line with Root (1998) who identifies an efficient market in the case of a two month futures contract.

For the four month contract, both unbiasedness (p = 0.038) and strict market efficiency (p = 0.013) are rejected at the 95% significance level, implying that the market is either inefficient, or that a time varying risk premium is inherent to the market at the four month time horizon. Finally, in the case of the 36 month contract, the null hypothesis of unbiasedness is rejected (p = 0.0000), whereas that of strict market efficiency (p = 0.8088), upholds, suggesting that a constant risk premium exists that renders 36 month natural gas futures prices biased, but efficient.

Table 4.1
Testing Equation (4.1), the Efficiency Hypothesis ($\beta_1 = 1$) and the Hypothesis of Unbiasdeness ($\beta_0 = 0$ and $\beta_1 = 1$)

	$\hat{\beta}_0$		$\hat{\beta}_1$		$H_0 : (\beta_1 = 1)$		$H_0 : (\beta_1 = 1$ and $\beta_0 = 0)$	
	Coefficient	p-value	Coefficient	p-value	t-statistic	p-value	F-statistic	p-value
2 months	0.132	0.123	0.899	0.000	3.480	0.065	1.950	0.147
3 months	0.185	0.056	0.862	0.000	5.220	0.024	2.870	0.061
4 months	0.234	0.038	0.832	0.000	6.450	0.013	5.000	0.028
36 months	0.533	0.001	0.969	0.000	0.060	0.809	96.66	0.000

4.2.2 Engle-Granger Cointegration Analysis

Cointegration implies a stationary long run relationship between two difference stationary time series. In this sub section, cointegrating vectors between natural gas futures and spot prices are estimated, and, in the spirit of Serletis and Scowcroft (1991), are tested by application of OLS.

The first step in cointegration analysis involves establishing the order of integration of the time series. In the preceding chapter, it was established that Henry Hub spot price is first difference stationary. It now remains to ensure that the log of the two, three, four and 36 month futures contract price data series, as well as the log of Henry Hub spot price are also first difference stationary. To this end, I follow exactly the same methodology as was used in Chapter 3 - I utilize both the ADF, (Dickey and Fuller, 1979 and 1981) and the Phillips-Perron, (Perron, 1988) tests. The number of lags in the ADF regression was taken to be the order selected by the AIC plus 2, as suggested by Pantula *et al.* (1994) and utilized by Sereltis and Rangel-Ruiz (2004)[20]. The marginal significance levels of both the ADF and the Phillips-Perron tests are reported in Table 4.2. Based on corresponding p-values, it is strongly confirmed that the log of spot as well as the log of all futures price series are first difference stationary.

[20] See Pantula *et al.* (1994) for a discussion of the advantages of using this rule for choosing the optimal number of augmenting lags.

Table 4.2
Marginal Significance of ADF and Phillips-Perron Tests for Log of Henry Hub Spot and Futures Natural Gas Prices

Series	Lag	Levels		First Differences	
		ADF	PP	ADF	PP
spot price	5	0.325	0.133	0.001	0.000
2 month contract	4	0.451	0.474	0.000	0.000
3 month contract	4	0.505	0.501	0.000	0.000
4 month contract	4	0.529	0.538	0.000	0.000
36 month contract	4	0.763	0.893	0.000	0.000

Sample period, monthly data: 01-1998 to 04-2007

Since both the futures and spot price series were found to be I(1), the question now, is whether there exists some long run equilibrium relationship between the futures and spot price pairs. Using the same definitions as in the preceding sub-section, the cointegrating regression:

$$P_{t+x} = \beta_0 + \beta_1 F_t + u_t \tag{4.2}$$

was estimated by OLS to obtain:

$$P_{t+x} = \hat{\beta}_0 + \hat{\beta}_1 F_t + \hat{u}_t \tag{4.3}$$

A test of the null hypothesis of no cointegration was then based on testing for a unit root in the regression residual, for each contract length. Borrowing from Herbert (1993), the basic, Dickey Fuller specification for such a test would be:

$$\hat{u}_t = \psi \hat{u}_{t-1} + \xi_t \tag{4.4}$$

where $\xi_t \sim$ n.i.d. For the same reasons as previously discussed, the ADF test, and the supplemental Phillips-Perron tests were both employed. Results are displayed in Table 4.3.

Table 4.3

Marginal Significance of ADF and Phillips-Perron Tests in Testing Stationarity of the Regression Residual in Equation (4.3)

Series	Lag	ADF	PP
2 month contract	4	0.002	0.000
3 month contract	4	0.004	0.000
4 month contract	4	0.001	0.000
36 month contract	4	0.024	0.002

Based on corresponding p-values, both the ADF and the Phillips-Perron tests imply rejection of the hypothesis that $\hat{\psi} = 1$ from the regression of equation (4.4) at levels below 5%, for all four price series under consideration. Thus, these tests unilaterally provide strong evidence of cointegration between natural gas futures at a futures contracts' inception and spot prices at the time of the corresponding futures contracts' expiry. This result of course implies that the natural gas market is efficient[21], in the absence of any time-varying risk premia.

4.2.3 Johansen's Trace Test

One of the criticisms of the Engle-Granger two step cointegration procedure is that it does not have well defined limiting distributions (McKenzie and Holt, 2002). To this end, here I buttress the test of the preceding subsection by employing the bivariate Johansen Trace test.[22] In order to do so, I specify a p-dimensional VECM as:

[21] Note that this method does not allow for the separate assessment of the unbiasedness and strict market efficiency hypotheses.

[22] Owing to the shortcomings of the Engle-Granger test, it is advised that the results of the Johansen test be used in the event that the two tests offer discrepant conclusions.

$$\Delta y_t = \sum_{i=1}^{k-1} \Gamma_i \Delta y_{t-i} + \Pi y_{t-1} + \mu + \varepsilon_t \tag{4.5}$$

where y_t denotes a matrix of first difference stationary futures price and spot price variables (i.e. $y_t = (s_{t+j}, f_t)$) for j = 2, 3, 4 and 36 months; $\prod$ denotes a $(p \times p)$ matrix of the form $\prod = \alpha\beta'$; α and β are $(p \times r)$ matrices of full rank and β contains the r cointegrating vectors. Next, this VECM is estimated by using one to six lags with the optimal number of lags chosen by the AIC criterion plus 2. Finally, the null hypothesis that there are at most r ($0 \leq r \leq p$) cointegrating vectors is tested using Johansen's likelihood ratio test statistic. Table 4.4 displays the results for each of the futures contract expiries considered.

Trace test statistics, presented in Table 4.4 indicate that the null hypothesis of no cointegration is rejected at the 5% significance level for the two, three and four month futures contracts, while the null hypothesis of one cointegrating relationship cannot be rejected. This suggests that spot and futures prices are cointegrated and thus that the natural gas market is efficient in the case of the shorter term contracts. For the 36 month contract, the null hypothesis of no cointegration cannot be rejected, providing evidence that the market is either inefficient, or that time-varying risk premium is inherent in the long term market.

Table 4.4
Johansen Trace Test for Cointegration between Natural Gas Futures and Spot Prices

H_0	2 month contract	3 month contract	4 month contract	36 month contract	Critical Values 5%	1%
r = 0	37.11**	53.16**	66.57**	8.91	15.41	20.04
$r \leq 1$	2.80	3.04	2.59	1.13	3.76	6.65

* indicates significance at the 5% level
** indicates significance at the 1% level

4.3 Concluding Remarks

Although all three tests for efficiency in the natural gas market yielded slightly different results, a preponderance of the evidence suggests that a unified trend can be detected. The results from all three tests unequivocally show that the natural gas market is both efficient and unbiased for the case of the short term (two and three month) contracts. Further, the Johansen test revealed that natural gas markets are efficient for the two, three and four month term structure, while for 36 month term structure the hypothesis of efficiency must be rejected. Owing to the inherent limitations of the first two tests, particular attention should be paid to the results of the Johansen Trace test. The intuition behind these results becomes quite clear when one considers the theoretical implications of the effect of contract term length on futures price risk premium. As conjectured by Inci and Lu (2005), risk premium should become an increasingly important component of the futures-spot price relationship as maturity of the futures contract increases due both to the nature and timeframe of hedging activities and by virtue of the axiom of covered interest parity[23]. This hypothesis is supported by the present study.

[23] By virtue of covered interest parity, the futures-spot basis is equivalent to the differential of the interest rates with the same maturity. The shortest end of the term structure of interest rates is typically not affected by the market risk premium, as it is set by central banks. Only further up along the yield curves are interest rates increasingly affected by the risk premium, as those rates are set by the market.

Chapter 5

The Interdependency of Natural Gas and Oil Futures Prices

Building upon the work of Brown and Yucel (2007), who establish a powerful relationship between oil and natural gas prices when conditioning for a number of exogenous variables inherent to the natural gas market, and contingent on the assumption that these exogenous variables cannot be easily forecast going forward, this chapter formally tests the hypothesis that natural gas futures prices and crude oil futures prices are cointegrated. By utilizing a modified version of the ECM proposed by Bachmeier and Griffin (2006), first I confirm the existence of, and subsequently quantify the degree of cointegration between Henry Hub natural gas, and WTI crude oil futures prices for two, three and four month futures contracts.

5.1 The Error Correction Model

Applying an ECM, Brown and Yucel (2007) demonstrate that movements in crude oil prices are highly cointegrated with those of natural gas prices if conditioned for by additional exogenous variables such as weather, seasonality, and natural gas storage and after accounting for episodes of hurricane related shut-in natural gas production[24]. While these exogenous factors are ones that are readily identified by market analysts as key drivers of natural gas prices on a day-to-day basis, for obvious reasons, the full list

[24] More specifically, the authors find that when these exogenous factors are taken into account, there is a continuum of prices at which natural gas and petroleum products are substitutes.

becomes increasingly difficult to forecast several weeks or months into the future. In recognition of this difficulty, the underlying assumption here is that though these exogenous factors are acknowledged to have a significant bearing on natural gas spot prices, they need not necessarily be included into derivations of natural gas futures price. Rather, contingent on the idea that *both* natural gas and crude oil markets are efficient so that crude oil futures prices are also viewed as optimal forecasts of future crude oil prices, the relationship between natural gas and crude oil futures prices is tested directly.

To this end, following Bachmeier and Griffin (2006) and assuming that both natural gas and crude oil futures prices follow are integrated I(1), a basic ECM:

$$\Delta NGF_t = \Phi_0 \Delta COF_t + \Phi_1 \Delta COF_{t-1} - \theta\left(NGF_{t-1} - \alpha_0 - \alpha_1 COF_{t-1}\right) + \varepsilon_t \qquad (5.1)$$

is employed, in which ΔNGF denotes the first difference in natural gas futures price and ΔCOF, the first difference in crude oil futures price. Notice that equation (5.1) involves the contemporaneous price change term as well as an error correction term that captures the long run cointegrating relationship of the system. Deviations from the long run cointegration relationship, ($NGF_{t-1} - \alpha_0 - \alpha_1 COF_{t-1}$) force the price adjustment back to the long run cointegrating relationship at a speed of adjustment of θ. Meanwhile, Φ_0 measures the contemporaneous price response between natural gas futures and crude oil futures prices. As in Bachmeier and Griffin's original model, two additional variables- instant % and half –life, are respectively calculated as:

$$\text{instant \%} = \Phi_0 / \alpha_1 \qquad (5.2)$$

$$\text{half-life} = \ln(0.5) / \theta. \tag{5.3}$$

Considering that a \$1 increase in WTI oil price gives rise to a change in natural gas price of α_1, instant % depicts the fraction of the long term change that is realized instantaneously. Any disequilibrium not captured by instantaneous adjustment is assumed to adjust exponentially at rate θ, which allows for calculation of the system's half-life.

Two features of the model require further elaboration. First, notice that in equation (5.1) causality is assumed to run from crude oil futures prices to natural gas futures prices. As pointed out by Bachmeier and Griffin (2006), a maintained assumption of the ECM is that the two prices in consideration are determined simultaneously, so that it makes little difference which variable is used as a regressor in the equation[25]. Secondly, as an augmentation to the Bachmeier and Griffin model, I include the term $\Phi_1 \Delta COF_{t-1}$ in the equation. This allows the effect of crude oil prices to enter with one lag as well as contemporaneously.

5.2 Data

Henry Hub natural gas futures prices and WTI crude oil futures prices, as sold on the NYMEX are obtained from the EIA website (http://www.eia.doe.gov) for contracts with expiries of two, three and four months. Although daily data is available, I employ

[25] For consistency of argument, here I use crude oil futures as the regressor.

monthly data to avoid problems associated with infrequent trading[26]. That is, each monthly price is taken as the closing price of the last business day of each month for each price series.

5.3 Results

The first step in examining trends between crude oil and natural gas futures prices is to test for the presence of a unit root in the autoregressive representation of each individual series. To this end, in the same fashion as seen in Chapters 3 and 4, the ADF (Dickey and Fuller, 1981) and Phillips-Perron (Perron, 1988) tests are applied. Table 5.1 displays p-values of these tests for the log level and logged difference of each price series, for each of the three contract expiries. For the ADF test, the optimal lag length was taken to be the order selected by the AIC plus 2, as suggested by Pantula *et al.* (1994) and utilized by Serletis and Rangel-Ruiz (2004)[27]. The marginal significance levels of the ADF and Phillips-Perron tests as well as the optimally chosen lag length are reported in Table 5.1.

As shown in the second and third rows of Table 5.1, the p-values for both the ADF and Phillips-Perron tests suggest that, the null hypothesis of a unit root in log levels cannot be rejected for any of the price series. Alternatively, the null hypothesis of a unit root in the logged difference representation is rejected. This implies that both natural gas and crude oil futures prices are first difference stationary for each of the contract lengths examined.

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[26] For a technical discussion on the merit of using last-day monthly price as opposed to daily price, the reader is referred to Root (1998).

[27] See Pantula *et al.* (1994) for a discussion of the advantages of using this rule for choosing the optimal number of augmenting lags.

To test for cointegration between oil and gas futures prices, equation (5.1) is used to compute an ECM for three sets of futures prices, matched by expiry month. Table 5.2 reports the results of the ECM as well as calculations for the instant % and half-life of the system. As revealed by the adjusted R^2 estimates of the system, the ECM explains approximately 20% of the variation in natural gas futures prices.

Table 5.1

Marginal Significance of ADF and Phillips-Perron Unit Root Tests

Series	Optimal lag	Log levels ADF	Log levels PP	Logged differences ADF	Logged differences PP
HH gas futures prices					
2 month contract	5	0.568	0.504	0.000	0.000
3 month contract	5	0.613	0.544	0.000	0.000
4 month contract	6	0.712	0.583	0.000	0.000
WTI oil futures prices					
2 month contract	3	0.925	0.938	0.000	0.000
3 month contract	3	0.938	0.949	0.000	0.000
4 month contract	3	0.948	0.957	0.000	0.000

Sample period, monthly data: 01-1997 to 04-2007

Table 5.2

Error Correction Model for Henry Hub Gas and WTI Crude Oil Futures Prices (equation 5.1)

	Contract Expiry Length		
	2 month	3 month	4 month
Φ_0	0.091	0.121	0.142
	(0.001)	(0.000)	(0.000)
Φ_1	0.028	0.031	0.030
	(0.280)	(0.196)	(0.189)
θ	0.217	0.190	0.180
	(0.000)	(0.001)	(0.001)
α_0	0.476	0.409	0.390
	(0.082)	(0.099)	(0.079)
α_1	0.128	0.131	0.133
	(0.000)	(0.000)	(0.000)
Instant %	70.8%	92.4%	107.4%
Half-life	3.2	3.6	3.9
Adjusted R^2	0.189	0.259	0.323

Sample period, monthly data: 01-1997 to 04-2007

Single tests for statistical significance on the long run cointegrating coefficient imply that crude oil and natural gas futures prices are cointegrated for each of the three expiries. For instance, in the case of the two month expiry price pair, a parameter estimate of α_1 (0.128) indicates that a one dollar per barrel increase in crude oil futures price raises the price of gas by 12.8 cents per MMBtu. Such a relationship is plausible in the context of the standard trading rules applied to natural gas trading. A one dollar to 12.8 cent relationship would suggest that the ratio of oil futures price to natural gas futures price is 7.8. This result is perfectly consistent with *a priori* expectations[28].

The contemporaneous price adjustment, Φ_0 falls between the range of 0.091 and 0.142. Due to the fact that natural gas and crude oil are not measured in similar units, on its own this statistic cannot be easily interpreted (Bachmeir and Griffin, 2006). Interestingly however, this contemporaneous price adjustment gives rise to an instant % which falls within the interval of 70.8% (for the two month contract future price pair) to 107.4% (for the four month contract future price pair). That is, for a change in crude oil futures price, the instant % denotes the fraction of the long term corresponding change in natural gas futures price that is realized instantaneously (in this case, within one month). At first glance, such a high instant % would seem to indicate a tightly integrated economic market. This is highly conceivable, however it is important to bear in mind that

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[28] To reiterate, Brown and Yucel (2007) identify three particularly standard natural gas trading rules:
(i) the simple rule of thumb, under which natural gas price is assumed to be one-tenth the price of crude oil price.
(ii) the energy content rule, which states that the price of one MMBtu of natural gas ought to equal one-sixth that of a barrel of oil in order to equate the energy equivalencies of the two hydrocarbons.
(iii) the Burner-Tip Parity rule, states that natural gas price adjusts so that gas pricing yields parity with residual fuel oil at the burner tip.

speculators and hedgers participating in futures trading often focus on day-to-day or even hour-to-hour arbitrage opportunities. As such, while the determination of intra-month integration between oil and gas futures markets is a considerable theoretical result, practitioners may question the applicability of such a finding.

The fact that instant % between crude oil and natural gas futures prices increases with contract expiry length, merits further discussion. Although analyzing the full scope of this result is beyond the scope of the present work, invoking Brown and Yucel's (2007) findings may help offer a potential explanation. Notably, if the relationship between natural gas and oil prices is in fact conditioned by exogenous factors such as weather, natural gas storage etc., where it is easy to argument that these exogenous factors become increasingly difficult to forecast as the forecast horizon lengthens, then it is feasible that the conditioning power of the exogenous variables diminishes as the length of term contract increases, leaving crude oil futures as a primary driver of natural gas futures prices.

Finally the coefficient θ (ranging from 0.180 to 0.217) reveals that disequilibria in the system rapidly adjust to a long run cointegrating relationship. Indeed, the half-life is between three and four months. In the case of the two month expiry contract, this means that in conjunction with 71% of adjustments occurring instantly, any remaining adjustments to long-run equilibria occur in less than 4 months. Of course, in the case of the 4 month contract this does not apply; given that all adjustments are instantaneous, there are no remaining adjustments to be made.

Chapter 6

Conclusion

Recently, a substantial volume of literature has emerged on modeling hydrocarbon exploration effort. Collectively implicit in such empirical models is the assumption that hydrocarbon producers form static or adaptive price expectations. In consideration of the fact that futures markets are generally the preferred trading arenas for hedgers and speculators on the market's next move (Shambora and Rossiter, 2007), and assuming that the Efficient Market Hypothesis holds, in this paper the alternative of a rational hydrocarbon producer was examined. A Fixed Effects model was judged to be optimal for the panel data set available, and was used to introduce 25-36 month futures prices into an integrationist model of natural gas exploration effort in the Western Canadian Sedimentary Basin. In support of the common perception among industry analysts, it was found that while spot price has a negative and statistically insignificant effect on exploratory effort, the influence of natural gas futures prices was both of the correct (positive) sign and statistically well determined. Additionally, the data suggests that technological improvement in the form of horizontal drilling had a statistically robust, positive effect. This finding highlights the importance of including specific measures of technological improvement into models of exploration effort.

In formal examination of the underlying assumption of market efficiency, this thesis also sought- through the use of both traditional and modern time-series methodologies- to provide a more rigorous investigation of efficiency of natural gas futures markets than has been previously performed. Results from all tests unanimously indicated that the natural gas market is both efficient and unbiased for the case of two and three month futures contracts. Application of the Engle-Granger ordinary least squares approach revealed that natural gas markets are efficient but biased for the long term (36 month futures) contract horizon, while application of the Johansen and Juselius cointegration technique showed that long term natural gas futures markets are either inefficient, or that a time-varying risk premium is inherent in the long term market. This finding takes on specific significance when viewed in conjunction with the result of the preceding chapter- that exploration effort is positively determined by long expiry futures prices.

In the final part of this thesis, the interdependency between natural gas and crude oil futures was assessed. An Error Correction Model was utilized to confirm the existence of, and subsequently, to quantify the degree of cointegration between Henry Hub natural gas and Western Texas Intermediate crude oil futures prices for futures contracts at the two, three and four month expiry horizons. Following Bachmeier and Griffin's (2006) methodology, it was discovered that natural gas and crude oil futures prices are statistically cointegrated in the long run at a ratio of approximately 1 to 7.8, and that, for any realized change in crude oil futures price, the corresponding change in natural gas futures prices occurs contemporaneously.

The current thesis offers a unique examination of natural gas exploration in North America, elucidates some key dynamics of natural gas futures markets and argues for the necessary interconnectedness of these two systems. The insights derived may prove useful to theorists, empiricists and practitioners alike as they continue to refine our understanding of an industry recently thrust into an increasingly global spotlight. It should be stressed however, that this paper represents a preliminary attempt to substantiate the links between the futures market, and natural gas supply. The models presented here can be improved considerably both in theoretical and empirical respects. Specifically, it would be interesting to examine how the element of price risk was to impact exploration effort. Intuitively, any economic risk should raise the opportunity cost of exploring of a hydrocarbon, and thus, an increase in futures price volatility should demand higher price expectations.

In an energy environment where natural gas demand is predicted to increase substantially in the near future, further research is needed to understand the intricate processes governing the market for this resource. It is hoped that the present work, at the very least, incites new questions in this research domain.

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