THE PREDICTIVE ACCURACY OF OVER-THE-COUNTER NATURAL GAS PRICE PROJECTIONS: A COMPARISON OF THE AECO AND SUMAS PRICING HUBS

by

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ABSTRACT

This study evaluated the forecast accuracy of over-the-counter (OTC) future natural gas price indications for two Canadian gas market centres: the Sumas hub near Vancouver, British Columbia, and the Alberta Energy Company (AECO) hub in south-east Alberta. The accuracy of both seasonal and monthly price projections were examined for the two hubs separately, and in comparison to each other. The statistical significance of hub location, seasonality, and the point in time at which OTC price predictions are made were investigated using step-wise multiple regression and dummy variables. Rolling average median forecast errors were calculated to determine if OTC forecast accuracy improved at the two hubs over the study period.

Regression results demonstrate that the independent variables selected play no statistically significant role in determining the predictive accuracy of OTC natural gas commodity price projections. This conclusion applies to both seasonal and near-month price projections.

The rolling median average showed that there is apparent learning occurring by market participants at both the AECO and Sumas market centres. That is, average prediction errors declined over the study period, indicating that OTC price projections are improving. Less improvement in forecast accuracy was evident for the Sumas index, evinced by continued significant errors for each rolling average period examined. This is the result of Sumas being more thinly traded than AECO, and because Sumas is less physically connected than AECO to the broader North American natural gas transportation and storage infrastructure. This observed improvement in forecast accuracy is surprising in light of the statistically insignificant results obtained through the regression analyses. Therefore, the forecast ability of OTC natural gas market participants must continue to improve if statistically significant results are to be obtained with the sort of analyses performed in this study.

The study provides further insight into price behaviour in the Canadian natural gas industry. Given the multi-billion dollar magnitude of the industry, even a slight improvement in understanding of pricing dynamics and a better appreciation of forecast bias has tremendous cost implications for all manner of market participants. The next level of analysis recommended — the explanation of why forecasts deviated to the extent they did from actual prices — would provide further insight into the workings of OTC markets and price forecasts.

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CHAPTER ONE

INTRODUCTION

Significance of the North American Natural Gas Market

In 1998, Canada consumed 2.6 trillion cubic feet (Tcf) of natural gas, while the United States consumed 21.3 Tcf, for a total continental consumption of 23.9 Tcf, or about 22,000 PJ (Natural Resources Canada, 1999). Of this volume, 5.1 Tcf was consumed by residential customers; 3.5 Tcf was consumed by commercial establishments; 11.8 Tcf was used by industry; and 3.4 Tcf was used by utilities to produce electricity. If a representative average gas price across the continent of $3.00 Canadian per thousand cubic feet (Mcf) is assumed, the dollar value of the North American natural gas commodity market is estimated to be over $70 billion Canadian.

The physical and dollar volumes of natural gas traded annually are obviously enormous. BC Gas, the natural gas distribution utility which serves the majority of British Columbia, spends over $800 million dollars annually on gas commodity and related costs to serve its 750,000 core market customers (BC Gas Inc., 1999).

North American Natural Gas Industry Evolution

Significant changes have occurred in natural gas pricing since the Canadian natural gas industry was deregulated in 1985. Prior to de-regulation, a small number of pipeline companies purchased the majority of Canadian gas production under long-term contracts. This gas was then re-sold and delivered to local gas distribution companies (LDC's) (Petroleum Communication Foundation, 1996).

Natural gas commodity prices are no longer regulated by government agencies. Instead, market forces have been allowed over time to play a greater and greater role in establishing more transparent and realistic energy prices. A host of new buyers and sellers has appeared in the gas marketplace as well, including agents, brokers, and marketers. Along with new market participants and greater market liquidity has come the establishment of pricing points — often referred to as "hubs" — which provide foci for buying and selling activities, and clear reference prices for all to observe and use (Brent Freidenberg and Associates, 1998a, de Vany and Walls, 1995). Although deregulation has been demonstrated to have reduced North American natural gas prices, the new market structure has created new market risks as well (Henning and Stewart, 1996).

One of the most significant developments in gas pricing occurred in April 1990 with the establishment on the New York Mercantile Exchange (NYMEX) of the first natural gas futures contract. Treat (1990) and DeVany and Walls (1995) describe in detail the history of the NYMEX contract's evolution and its particulars. The delivery point of the gas sold under the NYMEX contract was chosen to be in southern Louisiana, at the Henry Hub, a pipeline interchange near large production and consumption areas. The Henry Hub began operating in May 1988, and connects seven interstate pipelines, two intrastate pipelines, and one gas gathering system. The nearby offshore and onshore U.S. Gulf of Mexico natural gas fields currently yield nearly one-half of the continent's gas production. The high degree of market interconnection, the large number of buyers and sellers in the region, and the high levels of gas production have made NYMEX the benchmark continental gas market price. Prices in other regions are often referenced to the NYMEX price, in terms of the differential to the NYMEX contract.

Gas futures contracts offer buyers and sellers the ability to manage the price risk associated with the natural gas commodity (Energy ERA, January 1997, June 1999). A common practice is to buy gas on contracts in the "forward market". A forward contract is a commitment to buy (long) or sell (short) at a specified date, and at a price specified at the origination of the contract. The price in such an agreement is referred to as the "forward price". The "forward curve" is the sequence of future yields corresponding to the floating reference rates of a portfolio of forward contracts (Duke Energy Power Services, 1998).

While NYMEX acts as the North American benchmark price, numerous other hubs have also evolved since deregulation. While many hubs have been in existence and widespread use for less than a decade, they are heavily relied upon in making commodity-related decisions affecting millions of consumers and billions of dollars annually. The importance of hub-based pricing has further increased with greater use of sophisticated financial instruments, such as derivatives, price collars, swaps, and hedges of various sorts. (O'Neill, 2000; Walls, 1995)

Although widely used by a variety of natural gas industry participants, some parties view forward curves to be little more than speculation. That is, they see little reality in the forecasts of future prices inherent in these curves, and hence downplay their utility. Other parties are accused of relying too heavily on the forward market, and not enough on underlying industry fundamentals, in their buying and selling decisions (Energy Era, 1998a; Chan, 1999).

Over-the-Counter versus Futures Markets for Natural Gas

While some forward market indications exist at such exchanges as the NYMEX and the Kansas City Board of Trade, such natural gas pricing information is limited to only the most major natural gas "hubs" or market centres on the continent. There is little publicly available data on the forward price indications for other, less actively traded market centres, even though very large volumes of gas are bought and sold at such locations.

The over-the-counter (OTC) market is another development that has resulted from the deregulation of the North American natural gas market. An OTC market operates through dealers, or "middlemen", rather than through a formal exchange entity, such as NYMEX. OTC market dealers stand ready to buy or sell a given security on request, providing to buyers and sellers the benefit of being able to perform immediately desired transactions, rather than having to expend the effort themselves to locate parties wishing to do business.

While a given buyer or seller of gas is free to obtain price indications from the various parties involved in the OTC market, it must select which party or parties to obtain such information from, must often expend time and resources to do so, and does not know how accurate such predictions of future prices may be. Because OTC price quotations are confidential information provided between trading counter-parties, it is not possible to conduct ex-post analyses of OTC price indications in the same manner that NYMEX figures can be examined. Therefore, only active energy traders are able to determine —through both trading activity and in-house analyses — how reliable OTC predictions are.

CHAPTER TWO

LITERATURE SEARCH

Databases in the North American university library systems and the Internet were searched electronically using such key words and phrases as: "natural gas prices"; "natural gas forward curves"; "natural gas forecasts"; "natural gas options"; "over the counter markets"; and "energy commodity trading". A great many references were located related to energy market deregulation, energy commodity trading in general, and energy price forecasting (e.g.s., Labys and Granger, 1970; Brealey, et al, 1986; Chance, 1989; Treat, 1990; Foti and Dention, 1996). Numerous studies and texts also exist on energy demand and price forecasting techniques (e.g.s., Labys and Granger, 1970; Douglas, 1987; Clauss, 1996.) However, relatively little publicly available research exists on the utility of natural gas forward curves in a post-deregulation environment. The only references found relating to this specific topic were those prepared for clients by private sector consultants (e.g., Energy ERA, 1997c, 1999). A discussion of the references most relevant to this study follows.

Hartzmark (1991) examined the ability of both commercial and non-commercial (i.e., speculator) commodity traders to earn consistently positive profits. The study examined nine various sorts of markets, with seven of those being agricultural or livestock markets. The remaining two markets were those for U.S. treasury bonds and U.S. 90-day treasury bills. The author concluded that the empirical evidence provides "little support" for the hypothesis that commodity futures traders possess the ability or skill to make money consistently in these futures markets. Notably absent from this study was an examination of the ability of energy commodity traders. While the natural gas futures market was very young in 1991, oil had already been traded on the world market for many years by that point.

Doane and Spulber (1994) undertook an empirical analysis of U.S. wellhead spot prices to examine the effect of transmission pipeline open access on the geographic scope of the U.S. spot market for natural gas. This study used monthly spot price data for the 1984 to 1991 period, and applied and compared three statistical tests: price correlations, Ganger causality, and cointegration. Hartzmark looked only at U.S. producing basins, and did not examine the integration of market centres. The study found that the open market access created by deregulation had linked regional U.S. wellhead markets into a broader, competitive natural gas market. The authors also demonstrated that the introduction of competitive buying and selling of gas at the wellhead through open access effectively removed any incentives to continue long-term contracts between natural gas producers and transmission pipelines, a development which irrevocably altered North American natural gas market dynamics.

Walls (1995) tested a form of the efficient markets hypothesis in the market for natural gas futures using NYMEX futures contract data. Rather than focusing on only one location, Walls conducted his tests of market efficiency at numerous locations. These consisted of the U.S. natural gas spot market, namely the Henry Hub in Louisiana, which acts as the delivery point of the NYMEX futures contract; eight major transmission pipeline interconnections across the U.S.; and city gates at Chicago, California, and the Midwest. Walls concluded that the NYMEX futures market price "is generally consistent with the efficient markets hypothesis; that is, the futures market price is an unbiased predictor of the future spot price" at the Henry Hub. Walls also demonstrated that the NYMEX futures market price was an unbiased predictor, up to transmission costs, of spot prices at most of the other market locations examined. Interestingly, for the purposes of this study, the hypothesis of market efficiency was rejected for the Northwest Pipeline system in the Rockies region. This region is a major source of supply to U.S. Pacific Northwest gas buyers, competing with gas sourced at the Sumas hub east of Vancouver, B.C.

De Vany and Walls (1996) applied to the U.S. natural gas market a model of the law of one price for a network in which many markets are linked with a structure of paths. The law of one price holds if path(s) exist over which the commodity in question can flow to bring prices at two points on the network within arbitrage limits. Many arbitrage paths would reflect a strong market network for the commodity. The research demonstrated that the structure of the network greatly determines both arbitrage-free prices and dynamic prices. Based on their analyses, the authors concluded that local bypass and open access pipeline transportation created a sufficient number of arbitrage paths to city natural gas markets to cause city market prices to converge across the U.S. In other words, the authors concluded that in the wake of U.S. natural gas market deregulation, city gate and wellhead prices converged to one market. While the researchers determined that the network law of one price holds over most of the natural gas markets in the U.S. network, arbitrage paths insufficient to enable full market connection to occur existed for some markets. It is noteworthy that the Seattle city gate was discovered by the authors to be one of those poorly connected markets. Gas distribution utilities that serve the greater Seattle area and immediate surrounding regions purchase much of their gas at the Sumas hub.

Canada's National Energy Board (NEB) referenced the earlier work of De Vany and Walls in its assessment of the degree of price convergence in North American natural gas markets (National Energy Board, 1995). The NEB expanded the earlier research to include Canadian producing basins and export points. Statistical analyses of price behaviour were conducted on Canadian and U.S. natural gas market data to assess how "connected" the Alberta producing region price was to prices at Canadian export points and to selected U.S. hubs. This study showed that the degree of integration of the North American natural gas markets has increased since the start of deregulation. The NEB observed that, as of the mid-1990s, an east-west continental market split existed, with Alberta prices being more strongly linked to the western U.S. natural gas market than to that of the eastern U.S. The NEB study also demonstrated that the degree of connection between continental markets waxes and wanes over time, depending on supply and demand dynamics, and whether or not sufficient transportation infrastructure exists.

Walls' 1995 study used the mathematically rigorous approach of developing augmented Dickey-Fuller t-statistics. His conclusion that the NYMEX futures price was an objective predictor was confirmed by Calgary-based energy consulting firm Energy ERA (1997c). Energy ERA calculated the median prediction error for NYMEX monthly contract prices for the period from the inception of the contract April 1990 to January 1997. Because the median prediction error was exactly $0.00, the NYMEX futures contract was demonstrated to be an objective predictor of price over this period.

Energy ERA re-visited this study in 1999 (Energy ERA, 1999), and this time examined both the mean and median daily prediction errors for the NYMEX price for the 200 days before the close of trading. The mean error was found to be minus three cents, meaning that there tended to be a minor under-prediction of price. This under-prediction was not, however, statistically significant. The median prediction error was also found to be small, positive 2.2 cents. The positive median error was expected given that the distribution of errors was lognormal; that is, natural gas prices are able to move upwards to a greater extent than they can move down, given the inherent volatility and physical limitations of natural gas pricing (Energy ERA, 1997b). In times of tight supply — that is, during periods of very cold weather — buyers would pay whatever is required to ensure that they or their customers do not go without energy. Full transportation costs plus a high commodity cost would need to be paid during such times, and no price ceilings exist to limit the extent to which prices could rise. Conversely, during times of low demand, producers would not sell if they could not make an acceptable profit, meaning commodity price floors exist at producing basins. As well, during times of low market demand, pipelines may be shipping for far less than their full demand tolls, oftentimes recovering only the variable costs of operating their lines. Variable shipping costs thus act as a floor on transportation pricing.

Energy ERA (1998a) also assessed the utility of various forecasting techniques in determining natural gas prices. The inherent volatility of natural gas markets makes it difficult to use charting techniques and other technical analyses to forecast prices.

Nonetheless these techniques continue to be used by many parties, even though this approach ignores market fundamentals and relies instead only on historic price and trading volume data to assess future gas commodity prices. The presence of speculation funds in natural gas markets is increasing as technical analysis has proven successful for them. An increasing number of commercial players (that is, producers and buyers) are basing market-timing decisions on technical analysis. Although increasing use of such analysis may cause gas markets to exhibit less strong and less predictable cycles than in the past, actual price levels will continue to be key in market decisions.

Recognising the limitations of technical analysis, one study attempted to apply chaos theory to historical NYMEX futures prices to determine if order existed in the random-looking futures curves (Chwee, 1998). Even this emergent science could not find what is termed deterministic chaos in the most established of all natural gas forward markets.

The U.S. Gas Research Institute (1998) analysed nine key factors that shape North American natural gas markets. This study cited the development of an active natural gas futures market as "one of the major developments in gas markets over the last decade". The study noted that while commercial traders can and do use futures markets to speculate, these markets are predominantly used by these same traders to hedge future prices. The development of futures markets introduced market psychology as a new factor in the determination of continental natural gas prices. Market perceptions are altered greatly by the type, timing, and amount of market-related information available. Factors that affect market perceptions include changes in weather and major weather events such as hurricanes; energy industry strikes; pipeline failures; increases and decreases in industry drilling activity; and natural gas storage levels. A myriad of factors thus shapes the views of market participants whose buying, selling, and other trading actions develop the forward curves. The Institute noted that the natural gas market structure continues to evolve; that the level of participation in natural gas financial markets continues to increase; and that natural gas market participants continue to learn from history and adapt to the ongoing changes in the market.

Literature Review Conclusions

It is evident that a great deal of research has been performed on commodity trading and commodity futures. Even though the NYMEX futures contract is less than a decade old at the time of writing, a relatively large amount of research has already examined its behaviour and evolution.

Since the advent of gas market deregulation in North America, a significant amount of research has examined the evolution of continental price integration and related pricing dynamics. The bulk of this research has focused on U.S. producing areas and markets. A comparable amount of research has not been conducted on Canadian market centres and supply basins, despite the fact that Canadian gas supplies are an important and growing fraction of total U.S. natural gas consumption.

It is also clear that various types of price forecasting methodologies have been invented and researched for both energy and non-energy commodities.

Studies to-date have generally focused on yearly price changes or on examination of near-month prices. There does not yet appear to have been an examination of seasonal prices, either in terms of their evolution in the wake of deregulation, or their forecasting.

The natural gas futures market is young, and it is intuitive that market participants have learned a great deal since gas trading began almost a decade ago. With the advent of new and ever more powerful computers and related software, it is expected that trading ability is continuing to improve. It is also evident that knowledge about the workings of the continental natural gas market continues to increase.

Given the huge size of the North American natural gas market, it could be assumed that a great deal more research would have been done than it appears. It is more than likely that much natural gas-related research has in fact been performed, but that such research has been done by the private sector either internally or through confidential client studies by consultants. Given the commercial sensitivity of such information, it is not surprising that relatively little research of this nature exists in the public domain.

The gas market hubs examined by this research and the specific research questions asked are aimed at further exploring the dynamics of the evolving North American natural gas market.

Potential Utility of the Research Results

Establishment of a degree of confidence in the predictive ability of forward curves and the rationale behind such assertions would benefit the numerous parties buying and selling natural gas in North America. Research along these lines would ideally have the potential to:

- indicate the degree to which forward curves can assist in the forecasting of natural gas prices by various parties, such as gas distribution utilities and power generators.
- illustrate the relative forecast accuracy between seasonal versus monthly prices, and between winter and summer seasons. This would aid natural gas arbitrage activities and gas cost minimisation initiatives
- determine which variables are most key in predicting future natural gas prices.
- determine if OTC price predictions are becoming more accurate over time.
- assist in the education of parties new to the energy industry, and particularly to energy commodity trading.
- provide further insight into the ongoing evolution of the North American natural gas market.

CHAPTER THREE

METHODOLOGY

Selection of Gas Market Hubs to Study

Two Canadian pricing hubs, or natural gas market centres, were selected: AECO and Sumas.

The AECO Pricing Hub

The first hub selected for analysis is the AECO/NIT ("AECO") hub in southeastern Alberta, which acts as the major pricing hub for domestic and export Alberta gas sales. AECO is the industry term given to an interconnection point of gas gathering and transmission systems in southeastern Alberta. This hub is named after the Alberta Energy Company (AEC), one of the largest gas storage operators in the region. "NIT" refers to the NOVA interchange transfer point where gas from the Alberta gathering system — i.e., the NOVA pipeline system — connects to the export pipelines leaving the AECO area.

Gas is exported from Alberta on the major pipeline systems of TransCanada Pipelines, Alberta Natural Gas, and the Foothills Pipelines/Northern Border Pipeline Company. Alberta exports almost 11 Bcf/d out of province to Canadian and U.S. markets, or five times the flow on the Westcoast system (Natural Resources Canada, 1999). Gas from AECO flows southwest to California markets; southeast to U.S. Midwest markets; and eastward to Canadian and northeastern U.S. markets. AECO is also located near several large gas storage facilities. Such storage is filled during lower demand summer months, and the stored gas used to meet the higher demands during the winter heating season. Use of storage in this manner helps dampen seasonal price volatility (Herbert et al., 1997).

The Sumas Pricing Hub

The Sumas/Huntingdon ("Sumas") hub is the second market centre examined by this research. Sumas is located east of Vancouver in the Fraser Valley of B.C. where the

Westcoast Energy Inc. (WEI) pipeline inter-connects with the U.S. Northwest Pipeline (NWP) system. The WEI pipeline is a two billion cubic feet per day (Bcf/d) system that ships natural gas from producing areas in north-east B.C. south to both B.C. and U.S. export markets. NWP ships gas from Sumas southward to markets in the U.S. Pacific Northwest, and connects with other major transmission systems delivering gas to California. NWP also delivers gas from the U.S. Rockies gas-producing region west to the Pacific Northwest.

BC Gas, the province's largest gas distribution utility, connects its Lower Mainland gas delivery system to Sumas. Sumas is thus the most important pricing point for B.C., and an important hub for the U.S. Pacific Northwest as well. Utilities, energy marketers, and large gas consumers (such as large commercial operations and industrial facilities) in the region purchase significant portions of their gas requirements at the Sumas hub. The Vancouver market area is unique in North America in that it is the only large urban area that does not have natural gas storage facilities located in its immediate vicinity. This is in contrast to the U.S. Pacific Northwest local natural gas distribution companies (LDC's) who have large storage facilities in or very near their service areas. This is also in contrast to the AECO hub, which gained prominence as a natural gas trading point in part because of its proximity to gas storage facilities.

These particular hubs were selected largely because they are of great interest to Canadian buyers and sellers of natural gas, and relatively little research has been performed to-date on Canadian market centres. As well, the different market characteristics of the two hubs allows for a more interesting comparison of the relative impact of the different variables affecting gas prices.

Any examination of Canadian natural gas markets would, of course, have to include AECO. The inclusion of Sumas provides an interesting foil to AECO because Sumas is a newer, less liquid hub, and because the physical infrastructure surrounding the two market centres is very different. Sumas is located amidst a region where north-south gas flows predominate. Much of the gas consumed in the Pacific Northwest region originates in northeast B.C., and flows south to such major markets as Vancouver, Seattle, and Portland. Compared to the export volumes that flowed at Sumas and AECO, relatively little east-west movement of gas occurred across the Alberta-British Columbia border over the 1994-1999 study period. In contrast to Sumas, AECO is connected to a variety of Canadian and U.S. markets through a number of different, high-volume transmission pipeline systems. Therefore, natural gas is purchased at AECO by a much greater number of buyers, and AECO gas is sold into a much larger market area than is Sumas gas.

Research Questions to be Investigated

The research conducted by this study began by asking a number of questions regarding natural gas markets at the AECO and Sumas hubs. These questions are designed first to determine the relative utility of OTC gas market indicators at each of the two respective hubs. Second, the questions are aimed at revealing which variables are most significant in determining the accuracy of OTC price projections.

Question 1: Are AECO OTC Price Indicators More Accurate than Those for Sumas?

AECO OTC price projections are expected to be more accurate predictors of future price than those for Sumas because of the greater market liquidity at AECO. This prediction is based on the fact that a great deal more natural storage capacity exists at or near the Alberta hub than in the Sumas region. As well, a much greater number of intra-provincial and export pipelines inter-connect at AECO than at Sumas, and much higher volumes are traded. Daily flows at AECO during the winter heating season are in the order of 13 billion cubic feet per day (13 Bcf/d) while at Sumas they are slightly under 2 Bcf/d (Natural Resources Canada, 1998, 1999).

Question 2: Are Summer Season Price Forecasts More Accurate than Winter Season Price Forecasts?

It is postulated that summer season forward curve projections are superior to those made for the winter season for two reasons. First, there are seven months in the gas summer versus five in the winter, allowing a greater "smoothing" of month-to-month price fluctuations. Second, and more importantly, summer season gas demands are generally less "peaky" in nature as the weather extremes in the April-October period are less severe than those encountered in the November-March period. Consequently, lower summer demands mean that it is much less likely that gas supply constraints and associated price "spikes" will occur in the April-October period than in the winter gas season. The study seeks to determine if summer OTC price predictions are more accurate than those made for winter season prices.

Question 3: Does Forecast Error Improve Nearer in Time to the Price Finalisation Point?

It is intuitive that price projections forecasts made closer to the time at which natural gas prices are actually established should be more accurate than those made earlier in time. This study seeks to determine if the time at which price projections are made is a significant determinant in the accuracy of OTC predictions.

Question 4: Has the Accuracy of OTC Price Projections Increased Over Time?

For a number of reasons it is postulated that natural gas price forecasting, as represented by OTC price predictions, ~~has~~ become more accurate over time. First, all industry players are now much more familiar with the mechanics of a de-regulated marketplace than they were even a few years ago. There is greater familiarity with the physical infrastructure involved (e.g., pipeline locations, storage facility capacities and deliverability); with markets (continental regions, and customer types); and with the industry players (traders, shippers, pipeline companies, etc.). It is expected that since deregulation of the natural gas industry first began in October, 1985, industry participants would have developed in-house expertise in trading, purchasing, forecasting, and other fields that would allow them to participate more effectively in the marketplace. As the continental gas delivery and storage network continues to grow and evolve, the various producing basins and demand regions in North America continue to become more and more inter-connected.

Increasing inter-connections means increased market liquidity and price transparency across the continent. Finally, it is anticipated that the various producers and users of OTC price indications have learned from any past errors they may have made. Forecast accuracy over time will be examined to determine if there are any indications that industry participants have indeed "learned".

Data Collection

AECO has been in existence as a market centre, and has been more widely traded, longer than has Sumas. Accordingly, a greater amount of historical OTC data were available for AECO than for Sumas.

Monthly AECO OTC data were obtained for the period November 1994 to June 1999, providing a sample size of 54. Sumas monthly OTC data were only available for the period March 1997 to June 1999, yielding a data set of 28 monthly prices. For each monthly index price in the data series, four projections were examined: the price projection made four weeks prior to the start of that particular month; three weeks back from the start of the next month; two weeks back; and one week back. When these time periods coincided with weekends (when OTC trading does not occur), the price of the Friday prior to the weekend in question was selected.

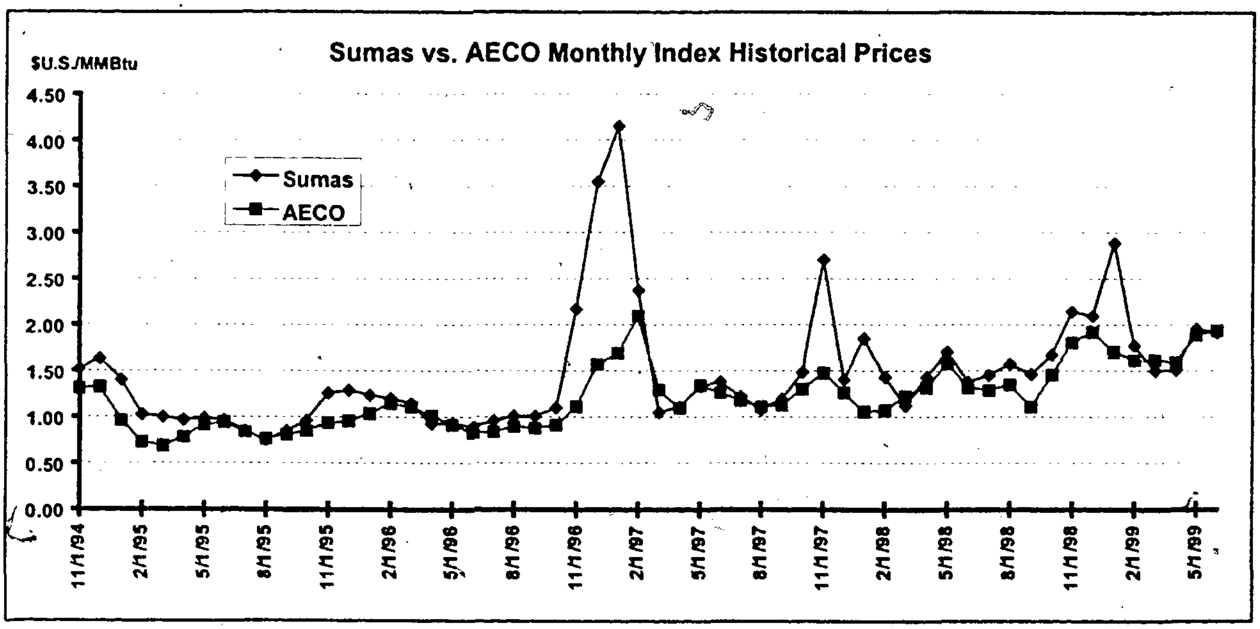
Far less seasonal than monthly forecast data exist for both hubs, and again more data were available for AECO than for Sumas. Summer OTC gas price indications were available for the years 1995 to 1998 inclusive for AECO, and for only 1997 and 1998 for Sumas. Five sets of winter gas price projections were available for AECO, from 1994/95 to 1998/99 inclusive. Three sets of winter price projections were available for Sumas, 1996/97 to 1998/99 inclusive.

Historical OTC data in the possession of BC Gas provided the numbers used in this research. OTC indications are confidential information shared between the entities doing the gas trading transaction; the buyers and sellers are known as the trading counter-parties. The identity of the energy traders used by BC Gas cannot be revealed due to the sensitive commercial nature of the information, and because BC Gas does not want the counter-parties with which it has been trading to be identified (Chan, 1999.) The OTC data used were therefore masked by averaging three separate parties' OTC projections for each forecast. Such averaging of counter-party price quotations also helped remove any inherent bias that particular energy traders may have. It can be mentioned, though, that the research employed the OTC price indications of eight different energy trading companies. Table 1 list natural gas traders who were actively involved in trading at either Sumas or AECO or at both hubs over the study period. Appendix A is an example of the sort of pricing sheet provided by OTC natural gas market participants.

Table 1: Natural Gas Trading Companies Active at Sumas and AECO Over the Study Period
Aquila Energy
Avista Energy
Bank of Montreal
Bankers Trust
Banque Parabis
BC Gas Utility Ltd.
CIBC Wood Gundy
Citibank
Coast Energy Canada
Coral Energy Inc.
Direct Energy Marketing
Duke Energy Marketing Ltd.
Dynegy Canada Inc.
El Paso Energy Marketing Canada
Engage Energy Canada
Enron Capital & Trade Resources Canada
Gerald Energy
J. Aron & Company
Koch Gas Services
Morgan Stanley Dean Witter
Pan-Alberta Gas Ltd.
PG & E Energy Trading Canada
Royal Bank of Canada
Sempra Energy Trading Corp.
Tenaska Marketing Ventures
Toronto Dominion Bank
TransCanada Gas Services

Actual price data were obtained from industry publications. *Inside F.E.R.C.* provided historical actual Sumas prices, which are given in U.S. dollars per million British thermal units ($U.S./MMBtu). AECO prices were obtained from *Canadian Gas Price Reporter*, and are given in Canadian dollars per Gigajoule ($Cdn/GJ). Because these pricing data are proprietary, they cannot be reproduced here in detail. Instead, Figure 1 illustrates the monthly index prices for both indices over the study period (November 1994 to June 1999), with AECO prices converted to $U.S./MMBtu.

Figure 1: AECO and Sumas Historical Monthly Index Prices



Note that while actual Sumas prices were available for the entire time period shown, useful OTC Sumas monthly price predictions were available only beginning March 1997, and fewer seasonal price predictions were available for Sumas than for AECO. Note, too, the pronounced price "spikes" which have occurred during recent winter periods at the Sumas index. The lack of similar behaviour at AECO reflects the facts that, first, AECO is better connected to the North American pipeline system, and, second, that a great deal more natural gas storage capacity exists in the vicinity of AECO than at Sumas. In other words, buyers and sellers have a great many more supply options at AECO than at Sumas, so there is less likelihood that physical supply will be tight at AECO.

Seasonal price prediction errors were calculated using the price predictions made at the start of the months leading up to the season in question. These are identified in the charts and tables presented in this report as the number of months back from the start of the particular gas season being examined. For example, for the April-October summer gas season, OTC price predictions made at the start of February are labelled "2 months back, and predictions made at the start of December are labelled "4 months back". Similarly, for the November-March winter gas season, OTC price predictions made, for example, at the start of the previous May are labelled "6 months back", those made the previous November are labelled "12 months back", and so on.

For both AECO and Sumas the number of seasonal prediction points varied by year. For AECO, the number of gas summer price predictions ranged from 14 for the 1998 April-October period to five for the 1995 summer. To these are added the six projections made in each year's April to September period; that is, during the summer period itself. Twelve price projections were obtained for the two Sumas summer periods for which data were available, 1997 and 1998. Adding the six April-to-September period projections yields eighteen data points for both summer seasons.

Gas winter OTC price predictions for the AECO hub varied from nine for the 1996/97 winter to 16 for the 1998/99 winter. Fewer predictions were available for Sumas winter prices. These ranged from eight for the 1996/97 winter to 12 for the 1998/99 winter. While data were available for four winters at AECO, OTC predictions were available for only three winters at Sumas.

The raw data used in this study are given Appendices B to G as described below. To further respect the confidentiality of the data used, only the percentage prediction error data are provided; that is, only the deviations of the price predictions from the actual prices are provided for the various indices over the study period expressed in percentage terms.

- Appendix B contains AECO monthly percentage price prediction errors for each of the four prediction periods (one, two, three and four weeks back from the start of the near month).
- Appendix C contains the monthly percentage price prediction errors for the Sumas index.
- Appendix D contains the percentage prediction errors over time for AECO gas summer prices.
- Appendix E contains the percentage prediction errors over time for Sumas gas summer prices.
- Appendix F contains the percentage prediction errors over time for AECO gas winter prices.
- Appendix G contains the percentage prediction errors over time for Sumas gas winter prices.

Numerical Approach Selected

Multiple Regression Analyses with Dummy Variables

A number of multiple regression models were developed to investigate the impacts on percentage change error. Step-wise regression was employed using statistical add-in software for Microsoft Excel. Dummy variables were employed to enable examination of the non-numeric characteristics that are hypothesised to affect the predictive accuracy of OTC price indications. Dummy variables and step-wise regression are standard statistical analysis techniques. They are discussed in detail, for instance, by Dilton and Goldstein (1984); Hair (1979); Mendenhall (1991); and Montgomery and Runger (1999).

Percentage error of the OTC price prediction was the dependent variable in the models developed for both monthly and seasonal prices. Percentage error is defined as:

(actual price - OTC prediction)/(actual price)

AECO and Sumas prices are quoted in different currencies and units; dollars Canadian per GJ and dollars U.S. per MMBtu, respectively. Definition of percentage error in this fashion enables the prices for both indices to be included in one data set.

The percentage error data were modified further by adding 100 percent to each of them prior to running the regression software. The regression results therefore indicate whether a data point is above or below 100 percent accuracy.

Separate models were built for monthly price predictions and seasonal price predictions. That is, one step-wise regression model was built to examine the predictive accuracy of monthly OTC indications. A second model was developed to examine the predictive accuracy of OTC predictions for natural gas seasonal prices.

The various independent variables selected were incorporated one at a time into separate regression models, and then the various variables incorporated incrementally into combined models. The monthly OTC prediction error model began by first looking only at the difference in predictive accuracy between Sumas and AECO. In this model version Sumas variables were assigned a value of "1" and AECO data points were assigned a value of "0". Next, the difference between summer and winter monthly price predictions was examined with price prediction errors corresponding to winter months given a value of "1" and errors corresponding to summer months were given the value "0". The third model used the price prediction point as the independent variable. This is the point in time at which the price prediction was made; that is, at one week, two weeks, three weeks, or four weeks back from the start of the near month. As four price prediction points existed, three columns of independent variables were required. The first had values of "1" given to all price prediction errors corresponding to price predictions made one week back from the start of the near-month. The remaining price prediction errors — i.e., for two, three, and four weeks back — were assigned the value "0" in this column. The second column had errors corresponding to the two weeks-back price prediction point assigned the value of "1". All other price prediction errors were given the value "0". The third column had errors corresponding to the three weeks-back price prediction point assigned the value of "1". All other price prediction errors were given the value "0" in this column. The final monthly model incorporated all these separate independent variables; i.e., the variables relating to season, hub location, and price prediction point.

All price prediction errors for both winter (November to March) and summer (April to October) periods were combined into one data set which was then analysed by various step-wise regression models. The seasonal OTC prediction error models were constructed in the same manner as were the monthly OTC error models. Hub location and season of price prediction were used as independent variables in the first two separate models. Whereas the monthly models had to deal with only four price prediction points, the seasonal data base had to be expanded to look at 14 one-month price predictions. The percentage error used as the dependent variable in this case was the percentage error at the start of the first month of the season in question. For gas summer seasons, this would be the overall seasonal price prediction error calculated using the prediction made at April 1 of each summer period in the data set. Similarly, for gas winter periods, the seasonal price prediction error was calculated using the prediction made at November 1 of each winter period in the data set. Fourteen months of historical pricing predictions were used for the seasonal regression model data set.

Appendix H contains the data sets for the monthly price prediction error regression models. Appendix I contains the data sets used by the seasonal price prediction error models.

Monthly OTC Price Predictions

Five independent variables were used in the regression model. First, Sumas prices were assigned a value of 1 in the data set, and AECO given 0 to determine if OTC price prediction accuracy was dependent on the particular pricing hub.

Next, all price predictions made for any of the five winter months over the entire range of data available were assigned a value of 1. Predictions made for summer month prices were assigned a value of 0. This approach would enable determination of the degree to which seasonality played a role in OTC price forecast accuracy.

The remaining three independent variables were used to determine if the point in time at which price prediction was made had any significant impact on prediction error. Four price prediction points were used for monthly OTC price predictions: four weeks back from the start of the month for which the price was being predicted (i.e., the "near month"); three weeks back; two weeks back; and one week back. As dummy variables were being used, only three of these points needed to be included in the regression. Weeks one, two, and three were selected. Pricing prediction errors corresponding to these points in time were given the value of 1 in the data set, and 0 at the other points in time.

The complete data set, showing the various values of 1 and 0 for the respective variables, is provided in Appendix H.

Seasonal OTC Price Predictions

For seasonal price projections, there is no near-month as in the case of monthly projections. Instead, the percentage forecast error calculated for the first month of the season in question was used. In the case of the April-October (gas summer) period, the percentage forecast error used as the dependent variable was calculated as:

$$\frac{\text{([actual April-October average price] - [OTC prediction as of April 1])}}{\text{(actual April-October average price)}}$$

In the case of the November-March (gas winter) period, the percentage error was calculated as:

$$\frac{\text{([actual November-March average price] - [OTC prediction as of November 1])}}{\text{(actual November-March average price)}}$$

The seasonal price in each case was calculated as the mean of the monthly index prices for each respective season.

Forecast Error Over Time

Rather than regression analysis, a different approach was used to determine if natural gas price forecasts, as represented by OTC price predictions, have become more accurate over time. A rolling average price forecast error was created for each hub. Changes in this rolling average price indicator over time would indicate if any changes have occurred in OTC price prediction accuracy.

Table 2 summarises the break-down of the historical price forecast error data into shorter time periods of equal duration. All 28 Sumas monthly data points, and an abridged AECO data set of 28 monthly points were used. AECO's data set was shortened in this manner — from the 54 months of data available — to match the shorter time period for which Sumas OTC data were available, namely March 1997 to June 1999. As indicated in the table, an interval length of fifteen months was selected. This choice was somewhat arbitrary, but this length of average interval did provide over a dozen intervals to examine, and did extend greater than a one-year period, thereby encompassing both gas seasons. The first interval begins at the start of the data series, and averages the price for the period March 1997 to May 1998. The next 15-month average price was calculated by dropping the first month (March 1997) and adding the next in the series (June 1998), until the last data point, June 1999, was reached. In this manner, 14 rolling average price prediction errors were obtained over the study period. Table 2 below shows the 14 periods over which the rolling median average percentage forecast errors were calculated for both Sumas and AECO, and the period number corresponding to the respective time manner. (This numbering system was used to avoid crowding on the X-axis of the results graphs.)

For each month in the data set, the median average of the percentage errors for each of the four separate weekly price prediction points was calculated. Percentage errors were again used to permit comparison of the results for the two market centres studied, AECO and Sumas. Although data are available for all four price prediction points, the median average was calculated because it is assumed that if forecasters did learn and improve their forecasting ability over time, that such learning would have impacted the OTC indications made at each of the four weekly price prediction points. The calculated median averages are listed for each interval in Table 2.

Table 2: Rolling Percentage Forecast Error Data for Sumas and AECO

		Sumas Rolling Average Forecast Errors					AECO Rolling Average Forecast Errors				
Time Period	Period ID	1 wk back	2 wks back	3 wks back	4 wks back	median error	1 wk back	2 wks back	3 wks back	4 wks back	median error
Apr 98 - Jun 99	14	0.57%	1.27%	2.57%	3.83%	1.92%	0.05%	-1.20%	1.72%	1.04%	0.54%
Mar 98 - May 99	13	0.51%	0.47%	1.35%	2.19%	0.93%	-0.01%	-1.19%	1.64%	1.10%	0.54%
Feb 98 - Apr 99	12	-0.40%	-1.18%	-0.80%	0.52%	-0.60%	-0.38%	-0.99%	1.45%	0.88%	0.25%
Jan 98 - Mar 99	11	-0.69%	-1.15%	0.12%	1.88%	-0.28%	-0.55%	-1.23%	1.73%	0.73%	0.09%
Dec 97 - Feb 99	10	-0.84%	-3.21%	-2.87%	-3.88%	-3.04%	-0.32%	-1.21%	1.13%	-0.76%	-0.54%
Nov 97 - Jan 99	9	-0.58%	-1.13%	-0.74%	-1.07%	-0.91%	-0.94%	-0.98%	1.33%	0.18%	-0.38%
Oct 97 - Dec 98	8	0.03%	-2.13%	-2.96%	-3.31%	-2.55%	-0.82%	-0.58%	0.82%	-0.18%	-0.38%
Sep 97 - Nov 98	7	-0.36%	-1.86%	-1.74%	-2.81%	-1.80%	-1.12%	-0.22%	1.33%	0.24%	0.01%
Aug 97 - Oct 98	6	-0.45%	-2.98%	-1.74%	-3.58%	-2.36%	-0.82%	-0.10%	0.94%	0.09%	-0.01%
Jul 97 - Sep 98	5	-0.88%	-3.34%	-2.61%	-4.54%	-2.97%	-0.90%	-0.10%	0.42%	-0.39%	-0.25%
Jun 97 - Aug 98	4	-0.72%	-2.90%	-2.84%	-4.77%	-2.87%	-1.02%	0.13%	0.03%	-0.87%	-0.42%
May 97 - Jul 98	3	-1.55%	-3.08%	-2.88%	-4.14%	-2.98%	-1.09%	0.05%	0.06%	-0.40%	-0.18%
Apr 97 - Jun 98	2	-1.59%	-4.02%	-4.11%	-4.50%	-4.06%	-0.80%	0.00%	-0.59%	-0.26%	-0.42%
Mar 97 - May 98	1	-1.86%	-6.69%	-6.44%	-8.66%	-6.51%	0.11%	0.51%	-2.27%	-1.75%	-0.82%

Because data were only available for two to four consecutive seasons — depending on the hub and season — a similar rolling average statistic could not be calculated for seasonal OTC price projections.

CHAPTER FOUR

RESULTS

Summary Results

Table 3 summarises the percentage forecast errors for monthly OTC price predictions using a variety of statistical measures; namely mean error, median error, and standard deviation. This table also shows in ~~percentage terms~~ the maximum and minimum monthly price errors for each of the four price prediction points for both AECO and Sumas. "Maximum" refers to the greatest positive error, and "minimum" to the greatest under-prediction.

A similar summary table was not created for seasonal OTC price prediction errors as only a few years of seasonal price data exist. Therefore, the calculation of such summary statistics would be relatively meaningless.

Table 3 shows that for two, three, and four weeks back from the start of the near month the maximum percentage Sumas price prediction errors are notably higher than those for AECO, being at least 10 percent greater at all three prediction points. Only one week back from the start of the near month is Sumas lower, at about seven percent, versus almost 17 percent for AECO at that point.

At four weeks prior to the start of the near month, the greatest Sumas price under-prediction was -88 percent, whereas for AECO the greatest under-prediction error at this point was -31 percent, less than half the Sumas figure. Three weeks back the highest Sumas under-prediction error was almost -50 percent, whereas AECO was under-predicted by almost half that amount, or -26 percent. Two weeks back from the near month, the AECO error shrinks to about minus nine percent, whereas the Sumas error remains quite high at -43 percent. At one week back from the start of the near month the Sumas error finally falls to a relatively low value, -9.4 percent. The AECO under-prediction error at the same point is slightly higher at -11.7 percent, and up about three percent from the previous week.

Both the mean and median statistics demonstrate that Sumas prices were on average under-predicted over the study period. AECO prices, in contrast, tended to be over-predicted. Only one week back from the start of the near-month was AECO, on average, under-predicted, and only slightly at that.

In comparing AECO average percentage forecast errors to those of Sumas, it is evident from the table that, again, on average, AECO forecast errors appear to be smaller than those for Sumas.

Using standard deviation as a measure of dispersion, it can be seen that for 2, 3, and 4 weeks back Sumas data show greater variation than those for AECO. Only at 1 week back is the variation similar at both hubs.

Table 3: Summary Statistics for Near-Month OTC Price Prediction Errors in Percentage Forecast Error Terms

	1 Week Back		2 Weeks Back		3 Weeks Back		4 Weeks Back	
	AECO	Sumas	AECO	Sumas	AECO	Sumas	AECO	Sumas
Maximum	16.8%	6.8%	9.8%	21.5%	18.7%	31.8%	23.4%	34.0%
Minimum	-11.7%	-9.4%	-8.6%	-42.9%	-26.4%	-49.5%	-31.2%	-88.1%
Mean	-0.30%	-1.0%	0.35%	-2.9%	0.73%	-2.5%	0.09%	-3.5%
Median	-0.6%	-0.6%	0.4%	-1.2%	0.8%	-2.1%	1.5%	-0.01%
Std Dev	4.4%	3.9%	3.4%	13.1%	6.6%	17.1%	9.2%	26.2%

While an interesting summary, this table does not provide any detail as to the statistical significance of the independent variables selected for study. The next section discusses the results of the step-wise multiple regression performed to determine if such significance exists.

Regression Results

Tables 4 and 5 below show the detailed summary provided by the regression software for the monthly and seasonal price prediction error models, respectively. These are the final versions of the models that incorporate all the independent variables. The step-by-step sequential developments of the monthly and seasonal regression models are shown in Appendix H and Appendix I, respectively.

Figures 2 and 3 are the plots of the residuals for the monthly and seasonal price prediction error models, respectively. Residual errors in both plots appear randomly scattered. Therefore, it is concluded that no heteroscedasticity exists for either model. That is, the residuals appear to occur randomly about zero percent error.

The R-square value for the monthly model is only 0.055. The adjusted R-square statistic is 0.033.

The R-square value for the seasonal model is 0.063. The adjusted R-square statistic is extremely small, 0 to four decimal places.

Table 4: Final Model and Statistical Summary of Monthly Price Prediction Model

Final Model

Regression and Correlation

Observations	224
R Square	0.0546
Standard Error	0.1257
Adjusted R Square	0.0329
Multiple R	0.2337

ANOVA

	df	SS	MS	F	p value
Regression	5	0.1991	0.0398	2.5184	0.0306
Residual	218	3.4471	0.0158		
Total	223	3.646165162			

	Coefficients	Standard Error	t value	p value
Intercept	0.0117	0.0200	0.5838	0.5599
Wint Mo =1	-0.0559	0.0172	-3.2494	0.0013
S =1	-0.0212	0.0168	-1.2627	0.2081
1 wk back	0.0155	0.0238	0.6543	0.5136
3 wk back	0.0075	0.0238	0.3155	0.7527
2 wk back	0.0057	0.0238	0.2382	0.8119

Table 5: Final Model and Statistical Summary of Seasonal Price Prediction Model

Final Model - Seasonal Price Prediction Errors

Regression and Correlation

Observations	156
R Square	0.0631
Standard Error	0.1765
Adjusted R Square	0.0000
Multiple R	0.2512

ANOVA

	df	SS	MS	F	p value
Regression	15	0.2937	0.0196	0.6286	0.8475
Residual	140	4.3600	0.0311		
Total	155	4.653647247			

	Coefficients	Standard Error	t value	p value
Intercept	0.9963	0.0435	22.8828	0.0000
W =1	-0.0340	0.0285	-1.1936	0.2346
S =1	0.0407	0.0294	1.3849	0.1683
13 mo. prior	0.1903	0.1097	1.7346	0.0850
14 mo. prior	0.1902	0.1312	1.4499	0.1493
10 mo. prior	0.0413	0.0678	0.6083	0.5439
8 mo. prior	0.1053	0.0639	1.6492	0.1014
7 mo. prior	0.0867	0.0639	1.3582	0.1766
9 mo. prior	0.0840	0.0657	1.2789	0.2031
11 mo. prior	0.0805	0.0734	1.0978	0.2742
2 mo. prior	0.0744	0.0623	1.1939	0.2346
6 mo. prior	0.0749	0.0639	1.1728	0.2429
5 mo. prior	0.0719	0.0623	1.1534	0.2507
3 mo. prior	0.0666	0.0623	1.0689	0.2869
4 mo. prior	0.0637	0.0623	1.0223	0.3084
1 mo. prior	0.0384	0.0623	0.6171	0.5381

Figure 2: Plot of Residuals of Step-Wise Regression Model for Monthly OTC Price Prediction

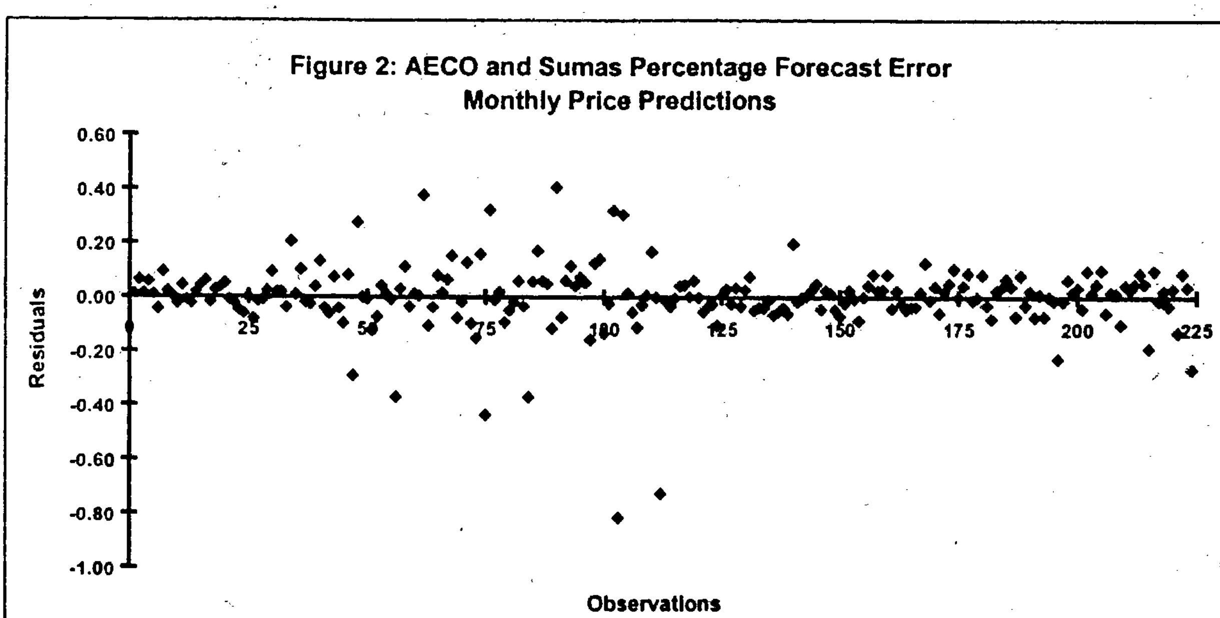
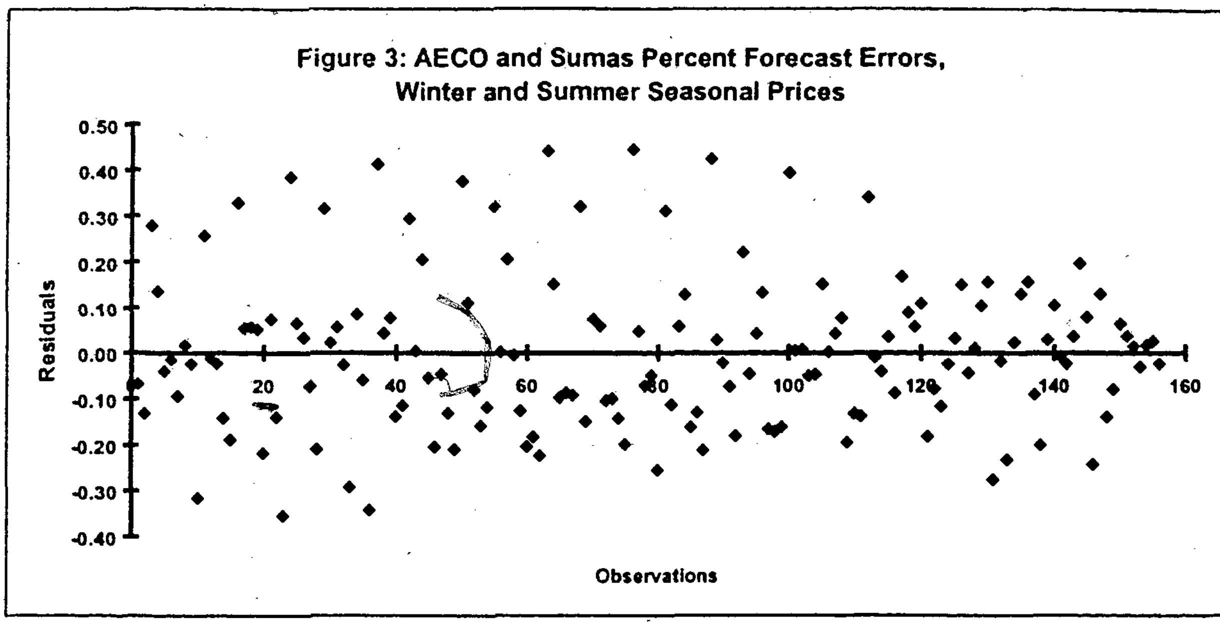


Figure 3: Plot of Residuals of Step-Wise Regression Model for Seasonal OTC Price Prediction Errors



Removal of Outliers from Monthly Price Prediction Model

Examination of Figure 2, the plot of the residuals for the monthly model, reveals the presence of a few outlier data points. These two points represent under-forecast errors of close to 80 percent each. The next highest errors were about plus and minus 40 percent.

The two outliers were identified as having occurred during for the monthly index prices for March 1997 and December 1997. Further research determined that these exceptionally large errors were caused by unusual events in the marketplace (Elgie, 2000; Hill, 2000). A major plant outage in the producing areas of north-east B.C. caused concerns about regional supply, resulting in a March 1997 monthly index price that was over 80 percent higher than OTC market participants were predicting would occur. Similarly, regional transmission pipeline operational difficulties caused the December 1997 prices to spike shortly before the near month, resulting in a monthly index price nearly 80 percent greater than earlier OTC projections.

Because these very large forecast errors occurred during periods when there were exceptional market disturbances, it was decided to remove all other price projections (i.e., those made 1,2,3, and 4 weeks back from the start of the near month) made at each hub from the data sample for the two months in question. In this manner only data reflecting typical market conditions were used. The regression analysis was then re-run. The output describing the final model is provided in Table 6. The adjusted R-square value dropped from 0.0329 for the model using the entire data set (Table 3) to 0.0000. The model as constructed obviously provides little explanation of the observed variations seen in the OTC price predictions.

Table 6: Final Model and Statistical Summary of Monthly Price Prediction Model – Outliers Removed from Data

Final Model - March and December 1997 Price Prediction Errors Removed

Regression and Correlation

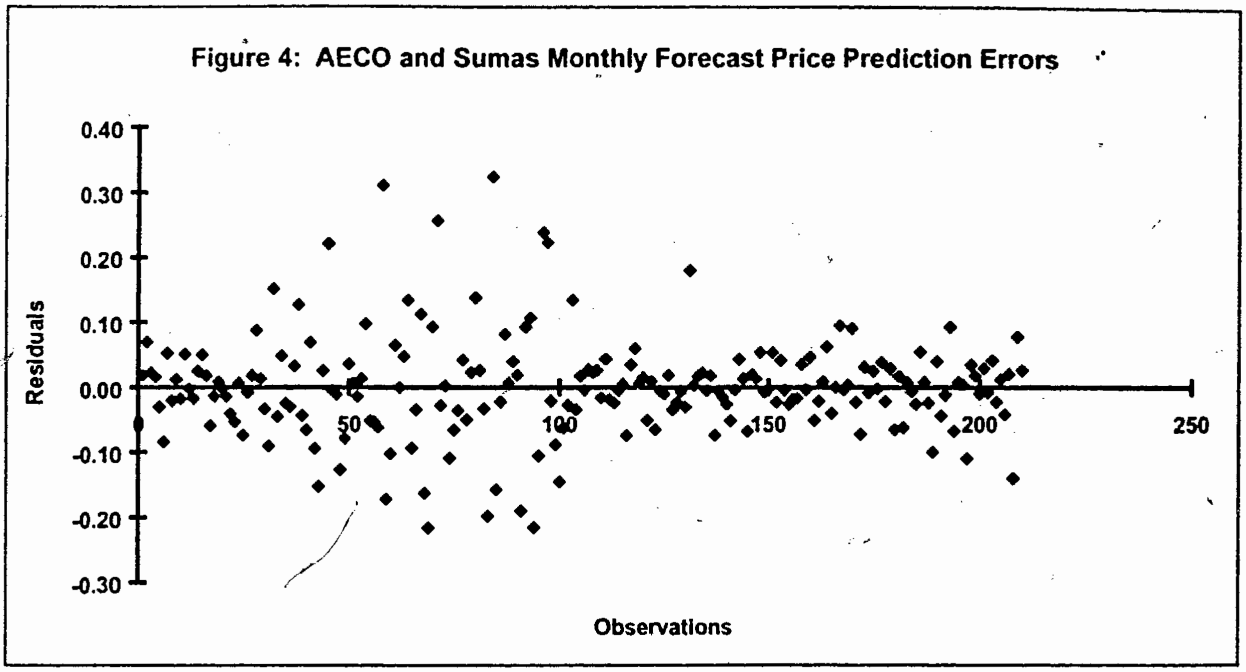
Observations	210
R Square	0.0194
Standard Error	0.0791
Adjusted R Square	0.0000
Multiple R	0.1393

ANOVA

	df	SS	MS	F	p value
Regression	5	0.0252	0.0050	0.8069	0.5459
Residual	204	1.2755	0.0063		
Total	209	1.300723022			

	Coefficients	Standard Error	t value	p value
Intercept	1.0214	0.0129	79.2233	0.0000
1 wk back	-0.0251	0.0154	-1.6251	0.1057
2 wk back	-0.0230	0.0154	-1.4927	0.1371
Wint Mo =1	-0.0074	0.0114	-0.6514	0.5155
3 wk back	-0.0096	0.0155	-0.6219	0.5347
S =1	0.0026	0.0109	0.2365	0.8133

Figure 4: Plot of Residuals of Step-Wise Regression Model for Monthly OTC Prediction Errors – Data Set with Outliers Removed



AECO versus Sumas Price Prediction Accuracy

<u>Monthly OTC Price Predictions</u>

Table 3 shows that the t-value for the Sumas dummy variable (represented by "S") in the monthly price prediction error model is about -1.26. This is not strongly significant, as indicated by a p-value of about 0.21.

The modified monthly model also shows that choice of market centre is not a statistically significant factor in determining the accuracy of OTC gas price projections. The variable representing hub choice ("S" in Table 5) has an extremely low t-value, 0.24. The very high p-value demonstrates how statistically insignificant the selection of pricing point is.

Seasonal OTC Price Predictions

Table 5 shows that the t-value for the Sumas dummy variable in the seasonal price prediction error model is about 1.38. This is not strongly significant, as indicated by a p-value of about 0.17.

The correlation coefficient for the hub-related variable in the seasonal model is 0.0407.

Winter versus Summer Seasonal Price Predictions

Monthly OTC Price Predictions

Table 4 shows that for the model using all data points, the t-value for the seasonal dummy variable (where "W" represents winter) in the monthly price prediction error model is about -3.25. This is statistically significant, reflected in a p-value of about 0.001. The correlation coefficient for the independent variable related to gas season is –0.0559.

However, as Table 6 indicates, this significance is lost once the two months of forecast errors related to the outlier data points are removed. The t-value representing the importance of seasonality on OTC price prediction error dropped to only –0.65. The very high value of the corresponding t-statistic, 0.52, demonstrates that once exceptional price perturbations are accounted for, that there is no statistical significance regarding whether or not the OTC price prediction was made for a summer or winter month.

Seasonal OTC Price Predictions

Table 5 shows that the t-value for the Sumas dummy variable in the seasonal price prediction error model is about -1.2. This is not strongly statistically significant, as indicated by a p-value of about 0.23.

The independent variable related to gas season has a correlation coefficient of –0.034.

Forecast Accuracy Over Time with the Approach of the Price Settlement Date

Monthly OTC Price Predictions

The t-values for each of the price prediction points (one, two, and three weeks back) are all far below a statistically significant level. In the model using all data points, the lowest p-value for any of the time-of-prediction variables is 0.51 for one week prior to the start of the near-month. The p-value for the two weeks prior variable is 0.81 (Table 4).

The beta values for each of the three prediction point independent variables were all positive, and all extremely small, ranging from 0.0057 for two weeks back to 0.0155 for one week back from the start of the near month.

The significance of price prediction points increased in the model which excluded the outlier data points. Table 6 shows how the relative significance of the pricing point-related variables has increased. The 1-week back variable is the most significant, having a t-value of –1.62. However, while much larger than the t-value of 0.65 it had in the original model (see Table 3), it is still not statistically significant. This is borne out by the relatively high p-value of about 0.11.

The t-statistic for the 2 weeks back variable likewise increased, from about 0.24 in Table 3 to –1.49 in Table 6. A p-value of about 0.14 indicates, though, that this variable remains statistically insignificant.

Similarly, despite a noticeable increase in the value of the t-statistic, the variable representing 3 weeks back from the start of the near-month shows an increase in the absolute value, essentially doubling from about 0.32 to about 0.62. While the p-value dropped noticeably — from about 0.75 to about 0.53 — the variable remains of little statistical significance.

Seasonal OTC Price Predictions

The t-values for each of the price prediction points (one, two, and three weeks back) are all far below a statistically significant level. The lowest p-value for any of the time-of-prediction variables is 0.51 for one week prior to the start of the near-month.

The beta values for each of the 14 prediction point independent variables were all positive. As well, all were larger than the correlation coefficients in the monthly model, ranging from 0.038 to 0.19. Nonetheless, the t-values associated with all 14 betas were less than two, and therefore statistically not significant. The highest t-value was 1.73 for 13 months back. This beta had a p-value of 0.085. The next highest was 1.45 for 14 months back. The p-value for this beta was 0.15. The lowest t-value was for one month prior to the start of the season. This prediction point variable has a p-value of 0.54.

Forecast Accuracy Over Time

Figures 5 and 6 show the plots of these median averages over time. To avoid cluttering the graphs, a period number has been assigned to each specific rolling average interval. The period numbers are shown in Table 6 alongside the respective periods they represent. In each graph, a linear trend line of the median error over time has also been plotted.

The 15-month AECO rolling average graph (Figure 5) shows that for the first interval (March 1997 to May 1998), the median error is a little less than minus one percent. By the time the last interval (April 1998 to June 1999) is reached, the error has changed sign, reaching about one half of one percent. The net change in error magnitude for AECO is therefore about 1.3 percent, moving from slight under-forecasts in general, to slight over-forecasts, based on the constructed statistic used. The reduction in absolute forecast error was about 50%, indicating, on the surface at least, that some minor improvement in overall forecasting occurred over the March 1997 to June 1999 period.

Table 6 shows that for each interval in question, the Sumas median error was significantly greater than that for AECO. In other words, by the measures used, forecast

Figure 5: Plot of Rolling Average Percentage Forecast Error – AECO Hub

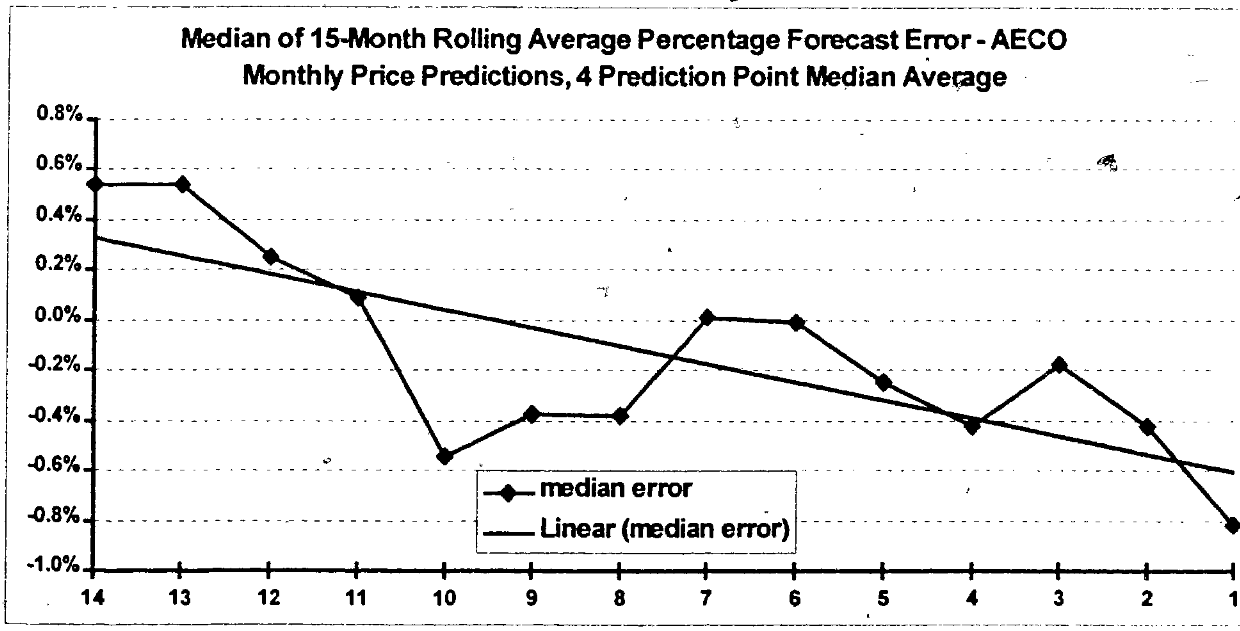
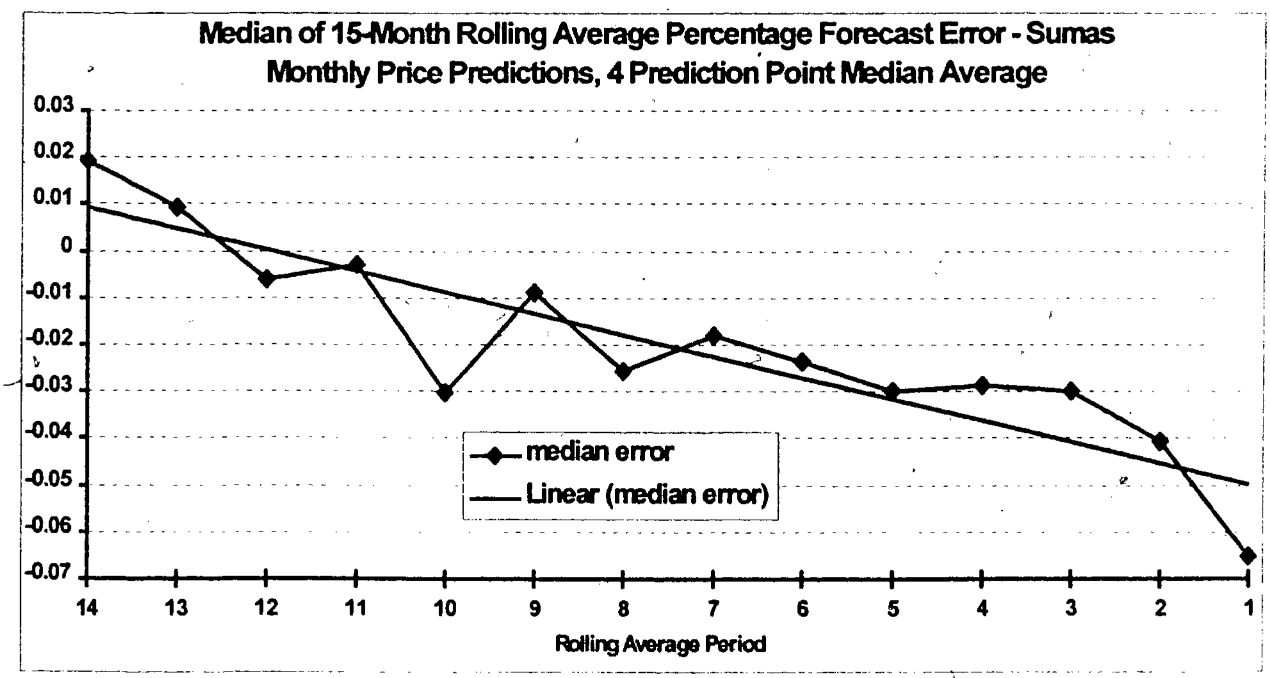


Figure 6: Plot of Rolling Average Percentage Forecast Error – Sumas Hub



accuracy increased at both pricing hubs over the interval of interest, but to a greater degree at Sumas. The plot of the Sumas rolling average median error over time (Figure 6) shows a clear change from an under-prediction of almost seven percent for the first 15-month period to an over-prediction error of about two percent for the last 15-month period. The trend line indicates that the absolute magnitude of forecast error over time shrunk from five percent in the first period to about one percent in the last interval.

CHAPTER FIVE

DISCUSSION

Summary Results

Based on Table 3 of the Results Section, it would appear that Sumas OTC price forecast errors are greater than those for AECO. However, a simple percentage comparison of this nature does not provide any information regarding statistical significance. It is precisely for this reason that the step-wise regression analyses were performed.

AECO versus Sumas OTC Forecast Accuracy

<u>Monthly OTC Price Predictions</u>

The independent dummy variable designed to determine whether or not OTC price predictions are more accurate at one of the two pricing hubs examined is statistically insignificant. This is based on the corresponding t-value being about 0.24 (see Table 5), which is well below the value of 2.0, the significance threshold for a 95% confidence level. The p-value of about 0.81 further reflects that this variable is statistically insignificant.

<u>Seasonal OTC Price Predictions</u>

The hub-related dummy variable in the seasonal model showed more statistical significance than that of the monthly model. While still below a clearly statistically significant level, the t-value of 1.38, and the corresponding p-value of 0.168, indicate the there is some significance in the selection of hub when it comes to OTC price projection accuracy. The correlation coefficient of 0.04 indicates that, on a seasonal basis, Sumas prices tend to be over-forecast by about four percent in comparison to AECO prices.

This conclusion appears contradictory, considering the characteristics of the two pricing points. Sumas appears at first contradictory to the monthly model conclusion. The relative lack of liquidity at Sumas — as reflected in the "spikiness" of Sumas monthly prices relative to AECO in Figure 1 — would imply that Sumas seasonal prices would tend to be under-forecast relative to AECO prices. The discrepancy is thought to be the result of two factors. First, the averaging of monthly prices into seasonal prices smoothes month-to-month price variations. Occasional, severe under-forecasts of Sumas prices are thus masked. As well, OTC market participants may have become accustomed to Sumas price spikes, given that they have occurred for three winters in a row. Accordingly, they may be more risk averse, and price Sumas at a higher price due to this past price behaviour.

Seasonal versus Forecast Month Price Prediction Accuracy

Monthly OTC Price Predictions

Prior to the removal of outlier percentage error data, the independent dummy variable designed to determine whether or not OTC price predictions are more accurate for winter or summer monthly prices is the most statistically significant variable of all those examined for either model. This variable's corresponding t-value is –3.25. It is the only variable used which has a p-value below 0.01, meaning it is the only variable that is the significant at a 99% confidence level.

However, with the removal of the outlier data, the significance of the variable representing seasonality of the OTC prediction disappeared. The new t-statistic has a value of –0.65 (Table 5), and a corresponding p-value of about 0.52. This relative lack of statistical significance reflects how great the significance is of price spike events on OTC price forecast errors.

The sign change for the correlation coefficients of the variables representing the time at which the OTC price predictions were made is noteworthy. Prior to removal of the outlier data points, the betas had been very small, but positive. With the outliers removed, the signs of the correlation coefficients changed from positive to negative. This is in keeping with the intuitive feeling that gas prices tend to be under-estimated rather than over-estimated. This, in turn, is the result of there being no price ceiling or cap above which prices cannot rise. If the market is willing to pay, the prices can rise dramatically when the demand exists, as reflected by the pricing history in Figure 1. However, a price floor does exist. Natural gas will not be sold at a value below the sum of the wellhead cost and the transportation cost to market. In any event, the correlation coefficients for the time-related variables remain small, indicating that they are not important variables in explaining the accuracy of OTC monthly price predictions.

<u>Seasonal OTC Price Predictions</u>

The dummy variable in the seasonal model used to determine if seasonality was in important factor in OTC price prediction accuracy was noticeably less statistically significant than the corresponding variable of the monthly model. The variable in the seasonal model has a t-value of -1.19, and a corresponding p-value of 0.235. Therefore some significance can be attributed to the role seasonality has in determining seasonal OTC price projection accuracy.

The correlation coefficient of -0.034 indicates that winter season prices tend to be under-forecast by slightly more than three four percent in comparison to summer season prices. The same reasons described in the discussion of the monthly model findings for the same independent variable also apply here. That is, the lack of a ceiling for gas prices and the characteristic upward price spikes during times of tight supply in the winter season explain why winter prices would tend to be under-estimated in relation to summer prices. Because summer gas demands are so much lower than during winter months, no similar price spikes occur during the April to October gas summer.

Forecast Accuracy Over Time with the Approach of the Price Settlement Date

<u>Monthly OTC Price Predictions</u>

None of the independent variables representing the time of prediction is statistically significant. As shown in Table 5, the highest t-value obtained was -1.65 for OTC price predictions made one week prior to the start of the near-month. The corresponding p-value was 0.106, which indicates that this variable is statistically insignificant at the 95 percent confidence level. Therefore, it can be concluded that price predictions made during the course of the month prior to the establishment of the index price are not statistically significant factors in determining what the final monthly index price will be.

All of the correlation coefficients are negative, but small. The largest absolute value is the time-related variables is coefficient is 0.025 for one week prior to the start of the near-month. The smallest absolute beta value is 0.0096 for the variable representing OTC price predictions made three weeks back from the start of the near month. This range in values is intuitive. That is, price predictions made closer to the actual time at which prices are established should be more accurate, and therefore more significant, than predictions made farther back in time.

Seasonal OTC Price Predictions

As is the case with the monthly regression model, none of the independent variables representing the time at which OTC predictions were made are statistically significant. The three largest t-values of 1.73, 1.65, and 1.45 correspond to the price predictions made thirteen, eight, and fourteen months back from the first month of the gas seasons examined. The lowest t-value — 0.61 — was obtained for price predictions made 10 months back. The second lowest t-value of 0.62 was obtained for price predictions made one month prior to the start of the gas season. These latter two variables each had p-values of about 0.54, clearly indicating that they were not statistically significant. The third lowest t-value — 1.02 — was obtained for the seasonal OTC price predictions made four months back. This variable has a p-value of 0.31 associated with it.

If time of prediction was a key variable, and therefore statistically significant, it would be intuitive that predictions made closer to the start of the season in question would be more significant than those made farther away. The apparent randomness in the t-values shown in Table 4 further reflect that time of prediction is not a statistically significant factor in the establishment of final seasonal gas prices.

Improvements in Forecast Accuracy over Time

Monthly OTC Price Predictions

Based on the particular rolling average error approach used, monthly OTC price forecast accuracy does appear to have improved at both AECO and Sumas over the study period. This is an intuitive result, as it is expected that as natural gas market participants become more familiar with other traders' buying and selling patterns, with specific market conditions, with the workings of the regional transportation and storage infrastructure, and so on, that their predictions would improve.

The magnitude of learning — that is, of forecast improvement — was noticeably greater at Sumas than at AECO. This is not a surprising result when it is remembered that AECO has been traded for a longer period of time than has Sumas. Very early AECO OTC forecast data may reveal a learning pattern similar to that seen with the Sumas data used in the study.

Although learning appears to have occurred, the independent variables examined through the regression analysis would indicate that OTC price predictions are not accurate predictors of actual prices.

Seasonal OTC Price Predictions

Only two to four periods of OTC seasonal price projections were available for the gas summer and winter seasons at the two pricing points investigated. This amount of data meant that the predictive accuracy of seasonal OTC price indications could not be examined to the same extent as monthly OTC projections.

CHAPTER SIX

CONCLUSIONS

Analytical Results

Step-wise multiple regression using dummy variables to account for effects of key parameters did not provide any statistically significant proof that OTC price projections are accurate predictors of future natural gas prices. Based on the analyses performed, it can be concluded that the predictive accuracy of over-the-counter natural gas commodity price projections has been extremely poor. This conclusion applies to both seasonal and near-month price projections

The rolling median average showed that there is apparent learning occurring by market participants at both the AECO and Sumas market centres. That is, grouped average prediction errors declined over the study period, indicating that OTC price projections are improving. This conclusion is surprising in light of the statistically insignificant results obtained through the regression analyses. Therefore, much more learning must occur by natural gas market participants if OTC predictions are to become sufficiently accurate to generate statistically significant results.

Utility of the Study Results

The study provides further insight into price behaviour in the Canadian natural gas industry, and places into the public domain information regarding the use and accuracy of OTC price projections. Given the multi-billion dollar magnitude of the industry, even a slight improvement in understanding of pricing dynamics and a better appreciation of forecast bias has tremendous cost implications for all manner of market participants.

Given that natural gas prices are so inherently volatile, and that de-regulation of the natural gas industry is continuing, some may assert that historical data are of little value in forecasting future prices. In other words, the criticism may be raised that past OTC price projection errors have little bearing on future OTC price prediction accuracy, given that future industry circumstances may be very different from those of the past. Past price behaviour will, regardless of the path industry evolution takes, remain a fundamental starting point in making any sort of price forecast. The next level of analysis — the explanation of *why* forecasts deviated to the extent they did from actual prices — would provide further insight into the workings of OTC markets and price forecasts.

While OTC price projections are of great use for price risk hedging and arbitrage, they should not be accepted as realistic projections of what the actual future price will be. Current market sentiments establish OTC bid and ask values for natural gas. Market supply and demand fundamentals — such as weather, economic activity, natural gas storage levels, and available pipeline capacity — continue to determine what the natural gas price will be in the end, not OTC calls made some time before.

CHAPTER SEVEN

RECOMMENDATIONS

1. Periodic Review of Forward Curve Predictions

Studies of this type should be conducted periodically, perhaps every two years or so. This will allow market participants to judge whether the predictive ability of natural gas forward curves is improving, staying the same, or worsening. It is expected that the utility of the Sumas forward curves should increase over time as the Sumas market becomes more highly traded and liquid.

2. Examine the Accuracy of Various Traders' Price Predictions

Each OTC price projection used in this study was calculated as the average of a number of separate parties' OTC price indications. This was done primarily to mask confidential natural gas trading information, but also acted to offset the effects of any inherent bias on the part of particular energy traders. There could, for instance, be certain traders who consistently price in a non-objective manner.

The same sort of multiple regression model used in this study could be used to investigate if there is any significant difference between the OTC price projections made over time by the various natural gas market participants. That is, dummy variables could be used to account for such different characteristics as trader nationality (Canadian versus American) and physical location (Calgary versus Toronto versus New York).

3. Examine "Shoulder" and Peak Seasonal Periods as Well

Analyses similar to those performed in this study could also be done for "shoulder seasons"; that is, those periods of time between peak seasonal periods. The peak winter heating demand period is December to February, and the peak summer demand period — when large gas volumes are consumed to generate electricity to meet air-conditioning loads — is June to August. The autumn shoulder season would be the September to November period, during which there is little cooling demand, and when space-heating demand begins to increase. The spring shoulder period would be the March to May period, when heating demand lessens, and before the arrival of hot weather. Dummy variables could be used to investigate the relative forecast accuracy of OTC price predictions for these new monthly groupings.

Such analyses would assist buyers and sellers who transact for natural gas in a manner that suits their particular supply and demand characteristics. The traditional November-to-March and April-to-October breakdowns may not be optimal for all market participants. For example, the gas winter ends earlier in B.C. than it does in Alberta, while the summer lasts significantly longer in the southern U.S. than it does in the north. Expanding the current analysis to look at other monthly groupings would assist such participants in assessing the relative accuracy of OTC price predictions for non-traditional time segments.

4. Accounting for Natural Gas Market Evolution

The North American natural gas market continues to evolve, with new parties entering the market, and new pipeline and storage infrastructure affecting regional and continental gas flows. Natural gas prices in Western Canada have been depressed at times due to insufficient export pipeline capacity out of the Western Canadian Sedimentary Basin (National Energy Board, 1995; Natural Resources Canada, 1998). In the wake of export pipeline expansions Western Canadian prices have jumped sharply. The anticipation of new capacity has caused rises in OTC price indications months before the start-up of any new capacity. A study could therefore be performed which would examine OTC forecast accuracy prior to and after major export pipeline capacity expansions. Dummy variables could be used to indicate periods of over-supply due to pipeline bottlenecks, and times when large storage capacity expansions occurred.

In addition to evaluating impacts of the industry's infrastructure development, the evolution of the make-up of the market should also be examined. Industry de-regulation has on one hand created a host of new market participants and ways of transacting for gas. Simultaneously, mergers and acquisitions are reducing the number of participants in other areas of the market. Increasing used of financial derivatives by such entities as pension funds has added another dimension to the natural gas market. Many market participants are thus far removed from analysing the fundamentals of the natural gas market, and instead trade based on certain "technical" parameters regarding price, margin, volume, timing, and so on. Dummy variables could be used to account for such factors as the number of natural gas trading companies; the number of actual traders active at a particular hub over time; and the impact of the introduction of new modes of transacting for gas, such as electronic commerce and financial derivatives.

Such analyses would most benefit natural gas market participants who transact at a number of different market centres. Knowledge of the effects of new infrastructure, new market participants, and new forms of transacting for gas would provide buyers and sellers with an appropriate degree of confidence in the utility of OTC price projections.

GLOSSARY

Agent: A party which has been given authority by natural gas buyer to act on the buyer's behalf to arrange or administer pipeline service, gas sales services, or both.

Arbitrage: The exploitation of differences between the prices of financial assets, currencies, or commodities within or between markets by buying where prices are lower and selling where they are higher.

Bid Week: The period in each month — generally the fourth week — during which parties transact for transportation and the natural gas commodity for the upcoming month.

Broker: A party which earns profit by arranging transactions between willing buyers and sellers of natural gas. Brokers never take ownership of the natural gas during the course of such transactions.

City Gate: The location at which natural gas ownership passes from one party to another, neither of which is the ultimate consumer of the gas. The city gate is where local distribution utilities receive gas purchased at the wellhead and delivered from the latter location via a transmission pipeline.

Commodity: A primary product, such as copper, rubber, cotton, lumber, petroleum, and natural gas.

Core Market: A LDC's core market consists of customers who are unable to relatively switch to an alternative fuel. Core market customers are typically the smaller customers of a utility, and, in the case of natural gas, use gas primarily for space heating. The natural gas core market includes residential, institutional, commercial, and small industrial customers.

Counterparty: A participant in a swap transaction.

Distribution, Gas: Refers to the infrastructure consisting of gas mains, service connection, meters, and other equipment that carry or control the supply of natural gas from the point of local supply to and including the sales meters at the point of customer usage.

Dummy Variable: In regression analysis, a dummy variable is an independent variable used to include or exclude the effect of a qualitative factor.

Forward Contract: A commitment to buy (long) or sell (short) an underlying asset at a specified date at a price specified at the time the contract is made. The price is known as the exercise or forward price.

Forward Curve: The sequence of future yields corresponding to the floating reference rates on a swap. Forward curves exist for all widely traded commodities. Such curves reflect commitments to buy or sell an underlying asset at prices and times specified beforehand.

Gas Summer: By convention, the period of the gas year from April 1 to October 31 when heating demands do not constitute a significant portion of North American natural gas demand.

Gas Winter: By convention, the period of the gas year from November 1 to March 31 of the following year, when North American heating demands are at their greatest.

Gas Year: By convention, the 12-month period from the start of the winter heating season of on year on November 1 to the end of the following gas summer on October 31.

Gigajoule (GJ): An S.I. unit of energy measurement, equivalent to 0.9478 million British thermal units (MMBtu). One GJ = one trillion Joules.

Hedging: The taking of action by buyers or sellers to protect their businesses or assets against a change in prices. The process of hedging protects the value of an investment form the risk of loss in case of price fluctuation.

Hub: An interchange where multiple pipelines interconnect and form a market centre. The major hub in B.C. is at Huntingdon/Sumas in the Fraser Valley, east of Vancouver. Alberta's major hub — named "AECO" after the owner of one of the major storage facilities in the region — is located in the south-east of the province at the interconnection of the provincial gas gathering pipelines and natural gas export pipelines.

The Henry Hub in southern Louisiana acts as the delivery point for the NYMEX natural gas forwards market.

Liquidity: In gas trading, a pricing point is said to be liquid if a high level of trading activity occurs there.

Local Distribution Company (LDC): A company which obtains the majority of its revenues from operating a retail distribution system to deliver natural gas or electricity to energy end users.

Long, Long Position: The position of a party who has purchased and is holding futures or options contracts or who owns a commodity that has not yet been settled by sale or delivery conditions.

Marketer: A party engaged in bringing together buyers and sellers of natural gas, usually on a spot market basis. Marketers earn revenue by assisting in buy/sell negotiations, and by arranging transportation and delivery terms.

MMBtu: An Imperial system unit of energy measurement, equal to one million British thermal units (Btu), and to 1.055 Gigajoules.

Multiple Regression: Regression analysis is a statistical technique used to discover the apparent dependence of one variable upon one or more other variables. Multiple regression aims to find a linear relationship between a response (dependent) variable and several possible predictor (independent) variables.

Near-Month: When making price projections, the near-month is the month following the month in which the price projections are being made. For example, a near-month monthly price projection made in September would refer to the October monthly index price.

NYMEX: Short for New York Mercantile Exchange. In the context of the natural gas industry, the NYMEX futures contract refers to North America's first natural gas exchange established in 1990. The contract prices at NYMEX reflect the physical delivery of gas at the Henry Hub in southern Louisiana on the Gulf of Mexico. This location was selected as the U.S. Gulf of Mexico accounts for such a large proportion of North American natural gas production, currently in the neighbourhood of 22 percent.

Over-the-Counter (OTC) Market: An OTC market operates through dealers, or "middlemen", rather than through a formal exchange entity, such as NYMEX. OTC market dealers stand ready to buy or sell a given security on request, providing to buyers and sellers the benefit of being able to perform immediately desired transactions, rather than having to expend the effort themselves to locate parties wishing to do business.

Pipeline Company: A firm engaged in the transportation of natural gas either intra-provincially, inter-provincially, or internationally. Examples of major Canadian natural gas pipeline companies are TransCanada Pipelines Ltd. and Westcoast Energy Inc.

Shipper: A party which contracts for transportation of natural gas from one specific pick-up location to a specified delivery point. Shippers retain title to the gas while it is being transported by the pipeline.

Short, Short Position: A party is in a short position when they have sold a commodity that they do not own with the expectation that they will be able to purchase it later at a lower price. A short sale is a contract for the sale of something not owned by the seller, such as a commodity or a futures contract. Short selling is a method of profiting from the expected fall in commodity prices, but users of such techniques run the risk that instead of falling, the price of the underlying commodity will rise, and the party will then face the financial penalty of having to purchase at whatever price the commodity reaches in order to cover the short sale.

Stepwise Regression: A regression technique in which one variable at a time is added or removed from a model which begins as a simple regression model, using what is deemed to be the best independent variable.

Swap: A portfolio of forward contracts. A swap is nearly identical to a sequence of forward contracts at different maturity dates. Swaps can be tailored to fit the needs of a particular counterparty.

Transmission Pipeline: A pipeline used to transport natural gas from supply areas to local distribution companies, large volumes customers (e.g., utilities to use for power generation, large industrial customers), or other transmission pipelines. Transmission pipelines are considerably larger than distribution pipelines, operate at a relatively high pressure, and traverse long distances.

Wellhead Price: The price received by the producer of natural gas or oil at the producing well site. Wellhead price plus pipeline transmission costs yields the city gate price.

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Appendix A:

Example of a Typical Over-the-Counter Pricing Sheet

Enron Capital & Trade Resources Canada Corp.

March 11, 1998

Natural Gas Price Indications - Close of Previous Business Day

AECO / NIT ($CND/GJ)	Fixed Price ($CND/GJ) BID	Fixed Price ($CND/GJ) OFFER	Basis ($US /MMBtu) BID	Basis ($US /MMBtu) OFFER	Aeco/Empress Transport BID	Aeco/Empress Transport OFFER
Day (Physical)	1.720	1.730	-	-	-	-
Rest of Month (Physical)	1.690	1.710	-	-	0.200	0.260
April 98 (Physical)	1.675	1.705	(0.885)	(0.855)	0.160	0.200
April 98 to Oct 98	1.665	1.695	(0.980)	(0.950)	0.100	0.130
Nov 98 to Mar 99	2.335	2.375	(0.735)	(0.695)	0.170	0.210
April 99 to Oct 99	2.035	2.075	(0.710)	(0.670)	0.070	0.100
Nov 98 1 YR	2.160	2.200	(0.725)	(0.685)	0.130	0.140
Nov 99 1 YR	2.170	2.210	(0.690)	(0.650)		

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Rob Benson	974-6764	Greg Kosinski	974-6909
Chris Calger	974-6751	John Lavorato	974-6758
Ken Clark	974-6920	Eric Le Dain	974-6741
Mike Cowan	974-6712	Rob Milnthorp	974-6714
Derek Davies	974-6793	Cynthia Pastega	974-6760
Paul DeVries	974-6904	Geof Storey	974-6774
Peggy Hedstrom	974-6753	Barry Tycholiz	974-6763
Keith Holst	974-6733	Jan Wilson	974-6706
Calvin Johnson	974-6786	Alan Wright	974-6772

	MALIN ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	SUMAS ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	TRANSCO Z6 ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	NYMEX ($US/MMBtu) SETTLE
Day (Physical)	2.050	2.090	-	-	1.590	1.630	-	-	2.600	2.700	-	-	-
April 98	1.815	1.845	(0.320)	(0.290)	1.220	1.270	(0.915)	(0.865)	2.360	2.380	0.225	0.245	2.137
April 98 to Oct 98	1.840	1.860	(0.390)	(0.370)	1.340	1.280	(0.990)	(0.950)	2.455	2.475	0.225	0.245	2.228
Nov 98 to Mar 99	2.265	2.315	(0.220)	(0.170)	2.075	2.115	(0.410)	(0.370)	3.415	3.430	0.930	0.945	2.487
April 99 to Oct 99	1.840	1.990	(0.400)	(0.250)	1.490	1.530	(0.750)	(0.710)	2.490	2.510	0.250	0.270	2.241
Nov 98 1 YR	2.015	2.125	(0.325)	(0.215)	1.735	1.775	(0.610)	(0.570)	2.875	2.895	0.535	0.550	2.344

	SAN JUAN ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	STATION 2 Fixed Price ($C/GJ) BID	Fixed Price ($C/GJ) OFFER	Basis ($US/MMBtu) BID	Basis ($US/MMBtu) OFFER	DAWN ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER
Day (Physical)	2.190	2.230	-	-	1.750	1.800	-	-	2.370	2.420	-	-
April 98	1.935	1.955	(0.200)	(0.180)	1.600	1.700	(0.940)	(0.865)	2.305	2.315	0.170	0.180
April 98 to Oct 98	1.995	2.005	(0.235)	(0.225)	1.640	1.720	(0.995)	(0.935)	2.360	2.370	0.130	0.140
Nov 98 to Mar 99	2.220	2.230	(0.265)	(0.255)	2.345	2.445	(0.720)	(0.645)	2.785	2.800	0.300	0.315
April 99 to Oct 99	1.970	2.000	(0.270)	(0.240)	1.895	1.995	(0.810)	(0.735)	2.365	2.385	0.125	0.145
Nov 98 1 YR	2.075	2.095	(0.270)	(0.245)	2.085	2.180	(0.775)	(0.695)	2.540	2.560	0.200	0.215

	ROCKIES ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	CHICAGO CITY GATE ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER	VENTURA ($US/MMBtu) Fixed Price BID	Fixed Price OFFER	Basis BID	Basis OFFER
Day (Physical)	2.060	2.100	-	-	2.360	2.400	-	-	2.320	2.380	-	-
April 98	1.765	1.785	(0.370)	(0.350)	2.190	2.210	0.055	0.075	2.035	2.055	(0.100)	(0.080)
April 98 to Oct 98	1.760	1.770	(0.480)	(0.460)	2.285	2.305	0.055	0.075	2.065	2.085	(0.165)	(0.145)
Nov 98 to Mar 99	2.145	2.165	(0.340)	(0.320)	2.690	2.705	0.205	0.220	2.410	2.430	(0.075)	(0.055)
April 99 to Oct 99	1.720	1.740	(0.620)	(0.600)	2.270	2.285	0.030	0.045	2.085	2.105	(0.155)	(0.135)
Nov 98 1 YR	1.895	1.915	(0.445)	(0.425)	2.445	2.460	0.105	0.120	2.220	2.240	(0.120)	(0.100)

All price indications are as of the close of the previous business day and do not constitute an offer to do business at these prices. All prices are financial unless otherwise noted.

Appendix B:

Monthly AECO Index Price Prediction Errors Over Time and by Period

Appendix B:

<u>Monthly AECO Index Percentage Prediction Errors Over Time and by Period</u>

Month	1 wk back	2 wks back	3 wks back	1 month back
Jun-99	1.3%	0.1%	0.8%	-0.4%
May-99	-0.8%	1.5%	5.8%	7.5%
Apr-99	2.3%	2.0%	-4.0%	2.9%
Mar-99	1.2%	-1.4%	-1.7%	-1.0%
Feb-99	1.5%	0.8%	1.3%	-8.6%
Jan-99	-2.7%	-8.3%	6.6%	5.3%
Dec-98	3.2%	-1.5%	-3.6%	-3.0%
Nov-98	-3.0%	-2.4%	0.4%	0.2%
Oct-98	-2.7%	-2.8%	10.7%	11.4%
Sep-98	-0.8%	-5.3%	0.8%	-4.7%
Aug-98	0.1%	-0.6%	1.5%	2.9%
Jul-98	-7.8%	4.1%	10.2%	2.6%
Jun-98	3.1%	1.1%	-1.1%	-8.9%
May-98	5.5%	-7.0%	-6.1%	5.5%
Apr-98	0.2%	1.7%	4.3%	3.9%
Mar-98	0.4%	0.4%	-0.4%	0.4%
Feb-98	-6.2%	4.5%	2.9%	4.3%
Jan-98	-0.2%	-1.6%	0.2%	0.6%
Dec-97	4.5%	-1.2%	-10.7%	-23.3%
Nov-97	-7.7%	4.4%	4.3%	5.5%
Oct-97	-0.9%	-2.4%	-1.0%	-0.1%
Sep-97	-1.4%	4.0%	4.1%	3.3%
Aug-97	1.5%	-0.6%	-5.4%	-2.1%
Jul-97	-3.8%	-2.8%	2.9%	4.1%
Jun-97	-2.6%	-1.9%	-5.2%	-11.9%
May-97	-1.0%	-1.8%	1.9%	9.9%
Apr-97	-3.4%	3.3%	0.6%	4.7%
Mar-97	16.8%	8.7%	-26.4%	-31.2%
Feb-97	-8.4%	-8.6%	11.7%	18.8%
Jan-97	-5.2%	-0.3%	6.1%	9.8%
Dec-96	-11.7%	0.4%	18.7%	23.4%
Nov-96	-3.4%	3.2%	3.5%	8.8%
Oct-96	-0.7%	-0.1%	1.6%	0.6%
Sep-96	-0.3%	0.2%	0.6%	-2.0%
Aug-96	-0.8%	-1.5%	-1.9%	6.5%
Jul-96	-0.6%	-0.1%	1.9%	2.2%
Jun-96	-2.2%	2.2%	-2.9%	-4.3%
May-96	-0.7%	1.4%	1.0%	-7.0%
Apr-96	0.0%	[illegible]	1.1%	-6.5%
Mar-96	3.9%	-0.9%	-5.1%	-9.5%
Feb-96	6.1%	9.8%	11.8%	9.1%
Jan-96	-2.4%	-0.9%	6.1%	8.0%
Dec-95	-0.6%	0.8%	-1.5%	1.9%
Nov-95	0.2%	0.6%	-3.0%	-4.0%
Oct-95	0.1%	1.9%	4.0%	3.3%
Sep-95	0.0%	-0.8%	2.6%	1.2%
Aug-95	-0.1%	1.5%	-0.1%	-2.9%
Jul-95	2.4%	-0.8%	-11.4%	-14.6%
Jun-95	-1.3%	2.0%	-0.3%	-2.1%
May-95	-1.8%	3.5%	5.8%	9.2%
Apr-95	-1.5%	-2.0%	5.4%	6.9%
Mar-95	-1.3%	1.2%	0.7%	2.3%
Feb-95	5.8%	2.2%	-2.0%	-11.8%
Jan-95	11.0%	6.7%	-7.3%	-13.9%
Feb-95	1.0%	0.7%	-6.8%	-11.1%
Mar-95	-1.0%	1.4%	7.0%	2.7%

Appendix C:

Monthly Sumas Index Price Prediction Errors Over Time and by Period

Appendix C:

Monthly Sumas Index Percentage Prediction Errors Over Time and by Period

Month	1 wk back	2 wks back	3 wks back	1 month back
Jun-99	1.7%	1.9%	2.7%	4.7%
May-99	6.8%	8.8%	11.2%	16.2%
Apr-99	2.1%	1.4%	-3.8%	5.0%
Mar-99	0.7%	-4.0%	-4.7%	-1.7%
Feb-99	-4.0%	-9.7%	-5.5%	-18.2%
Jan-99	-9.4%	14.6%	31.8%	34.0%
Dec-98	4.3%	-5.1%	-16.5%	-14.1%
Nov-98	-2.9%	4.2%	-9.6%	-0.6%
Oct-98	1.0%	-2.4%	7.8%	10.5%
Sep-98	-1.9%	-2.9%	1.4%	3.1%
Aug-98	4.9%	3.3%	6.2%	6.4%
Jul-98	-0.3%	12.8%	14.8%	4.3%
Jun-98	-1.8%	-4.3%	-8.0%	-16.7%
May-98	2.4%	-6.5%	-2.1%	11.6%
Apr-98	4.9%	7.0%	12.7%	13.1%
Mar-98	0.9%	-10.1%	-15.6%	-19.9%
Feb-98	-6.9%	-15.9%	-21.0%	-9.0%
Jan-98	-2.3%	1.9%	10.0%	25.5%
Dec-97	-1.6%	-35.0%	-49.5%	-88.1%
Nov-97	0.0%	21.5%	26.4%	24.0%
Oct-97	-0.3%	-0.5%	-1.4%	0.3%
Sep-97	-1.5%	-1.0%	1.7%	-6.5%
Aug-97	-4.2%	-12.7%	-9.6%	-12.2%
Jul-97	-5.5%	-7.8%	-5.2%	-3.9%
Jun-97	0.5%	3.6%	-2.2%	-0.4%
May-97	-7.5%	0.8%	5.6%	15.8%
Apr-97	-0.9%	-1.4%	-3.6%	-1.1%
Mar-97	-5.9%	-42.9%	-42.9%	-79.0%

Appendix D:

Prediction Errors by Period for AECO Index Summer (April - October) Natural Gas Prices

Appendix D:

Percentage Prediction Errors by Period for AECO Index Summer (April - October) Natural Gas Prices

Time Period	Apr-Oct 98 Fcst	Apr-Oct 97 Fcst	Apr-Oct 96 Fcst	Apr-Oct 95 Fcst
Sep 1 of pd.	1.8%	0.0%	0.4%	0.5%
Aug 1 of pd.	0.2%	2.5%	0.3%	0.8%
Jul 1 of pd.	0.3%	1.7%	2.3%	0.8%
Jun 1 of pd.	3.3%	3.6%	3.5%	11.1%
May 1 of pd.	0.1%	11.0%	0.0%	12.1%
Apr 1 of pd.	4.4%	2.0%	9.9%	1.2%
1 mo. prior	9.0%	8.7%	18.3%	10.9%
2 mo. prior	12.6%	4.4%	22.2%	15.5%
3 mo. prior	26.7%	0.9%	14.3%	1.7%
4 mo. prior	26.5%	5.5%	6.7%	14.4%
5 mo. prior	14.1%	12.7%	3.6%	3.1%
6 mo. prior	12.9%	19.8%	9.1%	
7 mo. prior	12.4%	21.6%	8.2%	
8 mo. prior	14.5%	17.9%	9.3%	
9 mo. prior	13.8%	18.9%	10.2%	
10 mo. prior	14.1%	19.3%	23.9%	
11 mo. prior	10.5%	18.1%		
12 mo. prior	12.5%			
13 mo. prior	20.2%			
14 mo. prior	16.2%			

Appendix E:

Prediction Errors by Period for Sumas Index

Summer (April - October) Natural Gas Prices

Appendix E:

Percentage Prediction Errors by Period for Sumas Index Summer (April - October) Natural Gas Prices

Time Period	Apr-Oct 98 Fcst	Apr-Oct 97 Fcst
Sep 1 of pd.	1.3%	2.7%
Aug 1 of pd.	1.2%	3.0%
Jul 1 of pd.	1.4%	5.7%
Jun 1 of pd.	1.4%	0.0%
May 1 of pd.	0.8%	9.5%
Apr 1 of pd.	2.5%	1.4%
1 mo. prior	14.1%	10.9%
2 mo. prior	15.4%	18.7%
3 mo. prior	21.3%	2.3%
4 mo. prior	25.1%	0.3%
5 mo. prior	15.6%	3.8%
6 mo. prior	14.0%	9.0%
7 mo. prior	12.9%	13.2%
8 mo. prior	13.2%	10.2%
9 mo. prior	9.7%	15.2%
10 mo. prior	10.0%	20.8%
11 mo. prior	9.4%	15.2%
12 mo. prior	10.0%	7.4%

Appendix F:

Prediction Errors by Period for AECO Index

Winter (November - March) Natural Gas Prices

Appendix F:

Percentage Prediction Errors by Period for AECO Index
Winter (November - March) Natural Gas Prices

Time Period	Nov 98 - Mar 99 Fcst	Nov 97 - Mar 98 Fcst	Nov 96 - Mar 97 Fcst	Nov 95 - Mar 96 Fcst
Feb 1 of pd.	0.0%	0.1%	-3.2%	-8.5%
Jan 1 of pd.	-3.5%	3.7%	0.7%	-10.7%
Dec 1 of pd.	-0.7%	4.3%	6.9%	8.2%
Nov 1 of pd.	-10.6%	-16.9%	24.1%	9.8%
1 mo. prior	-14.2%	-18.8%	32.8%	5.5%
2 mo. prior	-3.6%	-17.2%	34.9%	5.9%
3 mo. prior	-11.0%	-8.7%	32.1%	3.3%
4 mo. prior	-13.2%	-9.3%	34.4%	2.8%
5 mo. prior	-5.2%	-5.8%	35.3%	-11.5%
6 mo. prior	-1.2%	-21.8%	34.6%	-7.5%
7 mo. prior	-2.5%	-13.1%	26.8%	0.3%
8 mo. prior	1.7%	2.1%	21.8%	7.0%
9 mo. prior	8.2%	-4.1%	21.3%	13.5%
10 mo. prior	15.3%	-4.0%		1.4%
11 mo. prior	19.8%	-4.8%		-15.7%
12 mo. prior	15.7%	4.1%		-28.1%
13 mo. prior	16.7%	12.3%		
14 mo. prior	17.7%			
15 mo. prior				
16 mo. prior	24.3%			
17 mo. prior	25.9%			

Appendix G:

Prediction Errors by Period for Sumas Index

Winter (November - March) Natural Gas Prices

Appendix G:

Percentage Prediction Errors by Period for Sumas Index Winter (November - March) Natural Gas Prices

Time Period	Nov 98 - Mar 99 Fcst	Nov 97 - Mar 98 Fcst	Nov 96 - Mar 97 Fcst
Feb 1 of pd.	0.3%	-3.1%	-6.2%
Jan 1 of pd.	-4.2%	-3.2%	-8.4%
Dec 1 of pd.	9.5%	4.9%	3.9%
Nov 1 of pd.	-2.1%	-31.3%	25.9%
1 mo. prior	-9.8%	-31.4%	42.4%
2 mo. prior	1.7%	-26.5%	48.8%
3 mo. prior	-6.2%	-14.0%	44.4%
4 mo. prior	-11.5%	-15.7%	50.7%
5 mo. prior	-6.7%	-12.4%	51.8%
6 mo. prior	-5.3%	-13.3%	50.0%
7 mo. prior	-8.1%	-7.1%	48.1%
8 mo. prior	-2.4%	-2.9%	44.7%
9 mo. prior	0.9%	-2.9%	
10 mo. prior	2.7%	-18.8%	
11 mo. prior	7.5%		
12 mo. prior	-13.7%	-7.6%	

Appendix H:

Monthly Price Prediction Error
Step-Wise Regression Models and Data Sets

Appendix H:

Monthly Regression Model Data Set

		Error	S =1	Wint Mo =1	1 wk back	2 wk back	3 wk back
Sumas-1	Jun-99	101.7%	1	0	1	0	0
	May-99	106.8%	1	0	1	0	0
	Apr-99	102.1%	1	0	1	0	0
	Mar-99	100.7%	1	1	1	0	0
	Feb-99	96.0%	1	1	1	0	0
	Jan-99	90.6%	1	1	1	0	0
	Dec-98	104.3%	1	1	1	0	0
	Nov-98	97.1%	1	1	1	0	0
	Oct-98	101.0%	1	0	1	0	0
	Sep-98	98.1%	1	0	1	0	0
	Aug-98	104.9%	1	0	1	0	0
	Jul-98	99.7%	1	0	1	0	0
	Jun-98	98.2%	1	0	1	0	0
	May-98	102.4%	1	0	1	0	0
	Apr-98	104.9%	1	0	1	0	0
	Mar-98	100.9%	1	1	1	0	0
	Feb-98	93.1%	1	1	1	0	0
	Jan-98	97.7%	1	1	1	0	0
	Nov-97	100.0%	1	1	1	0	0
	Oct-97	99.7%	1	0	1	0	0
	Sep-97	98.5%	1	0	1	0	0
	Aug-97	95.6%	1	0	1	0	0
	Jul-97	94.5%	1	0	1	0	0
	Jun-97	100.5%	1	0	1	0	0
	May-97	92.5%	1	0	1	0	0
	Apr-97	99.1%	1	0	1	0	0
Sumas 2	Jun-99	101.9%	1	0	0	1	0
	May-99	108.8%	1	0	0	1	0
	Apr-99	101.4%	1	0	0	1	0
	Mar-99	96.0%	1	1	0	1	0
	Feb-99	90.3%	1	1	0	1	0
	Jan-99	114.6%	1	1	0	1	0
	Dec-98	94.9%	1	1	0	1	0
	Nov-98	104.2%	1	1	0	1	0
	Oct-98	97.6%	1	0	0	1	0
	Sep-98	97.1%	1	0	0	1	0
	Aug-98	103.3%	1	0	0	1	0
	Jul-98	112.8%	1	0	0	1	0
	Jun-98	95.7%	1	0	0	1	0
	May-98	93.5%	1	0	0	1	0
	Apr-98	107.0%	1	0	0	1	0
	Mar-98	89.9%	1	1	0	1	0
	Feb-98	84.1%	1	1	0	1	0
	Jan-98	101.9%	1	1	0	1	0
	Nov-97	121.5%	1	1	0	1	0
	Oct-97	99.5%	1	0	0	1	0
	Sep-97	99.0%	1	0	0	1	0
	Aug-97	87.3%	1	0	0	1	0
	Jul-97	92.2%	1	0	0	1	0
	Jun-97	103.6%	1	0	0	1	0
	May-97	100.8%	1	0	0	1	0
	Apr-97	98.6%	1	0	0	1	0
Sumas 3	Jun-99	102.7%	1	0	0	0	1
	May-99	111.2%	1	0	0	0	1
	Apr-99	96.2%	1	0	0	0	1
	Mar-99	95.3%	1	1	0	0	1
	Feb-99	94.5%	1	1	0	0	1
	Jan-99	131.8%	1	1	0	0	1
	Dec-98	83.5%	1	1	0	0	1
	Nov-98	90.4%	1	1	0	0	1
	Oct-98	107.8%	1	0	0	0	1
	Sep-98	101.4%	1	0	0	0	1
	Aug-98	106.2%	1	0	0	0	1
	Jul-98	114.8%	1	0	0	0	1
	Jun-98	92.0%	1	0	0	0	1
	May-98	97.9%	1	0	0	0	1
	Apr-98	112.7%	1	0	0	0	1
	Mar-98	84.4%	1	1	0	0	1
	Feb-98	79.0%	1	1	0	0	1
	Jan-98	110.0%	1	1	0	0	1
	Nov-97	126.4%	1	1	0	0	1
	Oct-97	98.6%	1	0	0	0	1
	Sep-97	101.7%	1	0	0	0	1
	Aug-97	90.4%	1	0	0	0	1
	Jul-97	94.8%	1	0	0	0	1
	Jun-97	97.8%	1	0	0	0	1
	May-97	105.6%	1	0	0	0	1
	Apr-97	96.4%	1	0	0	0	1

Appendix H (con'd):

Sumas 4	Jun-99	104.7%	1	0	0	0	0
	May-99	116.2%	1	0	0	0	0
	Apr-99	105.0%	1	0	0	0	0
	Mar-99	98.3%	1	1	0	0	0
	Feb-99	81.8%	1	1	0	0	0
	Jan-99	134.0%	1	1	0	0	0
	Dec-98	85.9%	1	1	0	0	0
	Nov-98	99.4%	1	1	0	0	0
	Oct-98	110.5%	1	0	0	0	0
	Sep-98	103.1%	1	0	0	0	0
	Aug-98	106.4%	1	0	0	0	0
	Jul-98	104.3%	1	0	0	0	0
	Jun-98	83.3%	1	0	0	0	0
	May-98	111.6%	1	0	0	0	0
	Apr-98	113.1%	1	0	0	0	0
	Mar-98	80.1%	1	1	0	0	0
	Feb-98	91.0%	1	1	0	0	0
	Jan-98	125.5%	1	1	0	0	0
	Nov-97	124.0%	1	1	0	0	0
	Oct-97	100.3%	1	0	0	0	0
	Sep-97	93.5%	1	0	0	0	0
	Aug-97	87.8%	1	0	0	0	0
	Jul-97	96.1%	1	0	0	0	0
	Jun-97	99.6%	1	0	0	0	0
	May-97	115.8%	1	0	0	0	0
	Apr-97	98.9%	1	0	0	0	0
AECO 1	Jun-99	101.3%	0	0	1	0	0
	May-99	99.2%	0	0	1	0	0
	Apr-99	102.3%	0	0	1	0	0
	Mar-99	101.2%	0	1	1	0	0
	Feb-99	101.5%	0	1	1	0	0
	Jan-99	97.3%	0	1	1	0	0
	Dec-98	103.2%	0	1	1	0	0
	Nov-98	97.0%	0	1	1	0	0
	Oct-98	97.3%	0	0	1	0	0
	Sep-98	99.2%	0	0	1	0	0
	Aug-98	100.1%	0	0	1	0	0
	Jul-98	92.2%	0	0	1	0	0
	Jun-98	103.1%	0	0	1	0	0
	May-98	105.5%	0	0	1	0	0
	Apr-98	100.2%	0	0	1	0	0
	Mar-98	100.4%	0	1	1	0	0
	Feb-98	93.8%	0	1	1	0	0
	Jan-98	99.8%	0	1	1	0	0
	Nov-97	92.3%	0	1	1	0	0
	Oct-97	99.1%	0	0	1	0	0
	Sep-97	98.6%	0	0	1	0	0
	Aug-97	101.5%	0	0	1	0	0
	Jul-97	96.2%	0	0	1	0	0
	Jun-97	97.4%	0	0	1	0	0
	May-97	99.0%	0	0	1	0	0
	Apr-97	96.6%	0	0	1	0	0
AECO 2	Jun-99	100.1%	0	0	0	1	0
	May-99	101.5%	0	0	0	1	0
	Apr-99	102.0%	0	0	0	1	0
	Mar-99	98.6%	0	1	0	1	0
	Feb-99	100.8%	0	1	0	1	0
	Jan-99	91.7%	0	1	0	1	0
	Dec-98	98.5%	0	1	0	1	0
	Nov-98	97.6%	0	1	0	1	0
	Oct-98	97.2%	0	0	0	1	0
	Sep-98	94.7%	0	0	0	1	0
	Aug-98	99.4%	0	0	0	1	0
	Jul-98	104.1%	0	0	0	1	0
	Jun-98	101.1%	0	0	0	1	0
	May-98	93.0%	0	0	0	1	0
	Apr-98	101.7%	0	0	0	1	0
	Mar-98	100.4%	0	1	0	1	0
	Feb-98	104.5%	0	1	0	1	0
	Jan-98	98.4%	0	1	0	1	0
	Nov-97	104.4%	0	1	0	1	0
	Oct-97	97.6%	0	0	0	1	0
	Sep-97	104.0%	0	0	0	1	0
	Aug-97	99.4%	0	0	0	1	0
	Jul-97	97.2%	0	0	0	1	0
	Jun-97	98.1%	0	0	0	1	0
	May-97	98.2%	0	0	0	1	0
	Apr-97	103.3%	0	0	0	1	0

Appendix H (con'd):

AECO 3	Jun-99	100.8%	0	0	0	0	1
	May-99	105.8%	0	0	0	0	1
	Apr-99	96.0%	0	0	0	0	1
	Mar-99	98.3%	0	1	0	0	1
	Feb-99	101.3%	0	1	0	0	1
	Jan-99	106.6%	0	1	0	0	1
	Dec-98	96.4%	0	1	0	0	1
	Nov-98	100.4%	0	1	0	0	1
	Oct-98	110.7%	0	0	0	0	1
	Sep-98	100.8%	0	0	0	0	1
	Aug-98	101.5%	0	0	0	0	1
	Jul-98	110.2%	0	0	0	0	1
	Jun-98	98.9%	0	0	0	0	1
	May-98	93.9%	0	0	0	0	1
	Apr-98	104.3%	0	0	0	0	1
	Mar-98	99.6%	0	1	0	0	1
	Feb-98	102.9%	0	1	0	0	1
	Jan-98	100.2%	0	1	0	0	1
	Nov-97	104.3%	0	1	0	0	1
	Oct-97	99.0%	0	0	0	0	1
	Sep-97	104.1%	0	0	0	0	1
	Aug-97	94.6%	0	0	0	0	1
	Jul-97	102.9%	0	0	0	0	1
	Jun-97	94.8%	0	0	0	0	1
	May-97	101.9%	0	0	0	0	1
	Apr-97	100.6%	0	0	0	0	1
AECO 4	Jun-99	99.6%	0	0	0	0	0
	May-99	107.5%	0	0	0	0	0
	Apr-99	102.9%	0	0	0	0	0
	Mar-99	99.0%	0	1	0	0	0
	Feb-99	91.4%	0	1	0	0	0
	Jan-99	105.3%	0	1	0	0	0
	Dec-98	97.0%	0	1	0	0	0
	Nov-98	100.2%	0	1	0	0	0
	Oct-98	111.4%	0	0	0	0	0
	Sep-98	95.3%	0	0	0	0	0
	Aug-98	102.9%	0	0	0	0	0
	Jul-98	102.6%	0	0	0	0	0
	Jun-98	91.1%	0	0	0	0	0
	May-98	105.5%	0	0	0	0	0
	Apr-98	103.9%	0	0	0	0	0
	Mar-98	100.4%	0	1	0	0	0
	Feb-98	104.3%	0	1	0	0	0
	Jan-98	100.6%	0	1	0	0	0
	Nov-97	105.5%	0	1	0	0	0
	Oct-97	99.9%	0	0	0	0	0
	Sep-97	103.3%	0	0	0	0	0
	Aug-97	97.9%	0	0	0	0	0
	Jul-97	104.1%	0	0	0	0	0
	Jun-97	88.1%	0	0	0	0	[illegible]
	May-97	109.9%	0	0	0	0	0
	Apr-97	104.7%	0	0	0	0	0

Appendix I:

Seasonal Price Prediction Error
Step-Wise Regression Models and Data Sets

Appendix I: Seasonal Regression Model Data Set

		Gas Season		Winter Pdce	Sumas	Price Prediction Point													
			% error	W = 1	S = 1	1 mo prior	2 mo prior	3 mo prior	4 mo prior	5 mo prior	6 mo prior	7 mo prior	8 mo prior	9 mo prior	10 mo prior	11 mo prior	12 mo prior	13 mo prior	14 mo prior
AECO	1st mo of pd	Nov 98 - Mar 99 Fcst	-10.6%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-16.9%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	24.1%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	9.8%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct98 Fcst	-4.4%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	-2.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-9.9%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	1.2%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-2.1%	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-31.3%	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	25.9%	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct98 Fcst	2.5%	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	1.4%	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AECO	1 mo back	Nov 98 - Mar 99 Fcst	-14.2%	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-18.8%	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	32.8%	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	5.5%	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	9.0%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	8.7%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-18.3%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	10.9%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-9.8%	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-31.4%	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	42.4%	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	14.1%	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	10.9%	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
AECO	2 mo back	Nov 98 - Mar 99 Fcst	-3.6%	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-17.2%	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	34.9%	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	5.9%	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	12.6%	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	4.4%	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-22.2%	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	15.5%	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	1.7%	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-26.5%	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	48.8%	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	15.4%	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	18.7%	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
AECO	3 mo back	Nov 98 - Mar 99 Fcst	-11.0%	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-8.7%	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	32.1%	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	3.3%	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	26.7%	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	0.9%	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-14.3%	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	1.7%	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-6.2%	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-14.0%	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	44.4%	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	21.3%	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	2.3%	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0
AECO	4 mo back	Nov 98 - Mar 99 Fcst	-13.2%	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-9.3%	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	34.4%	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	2.8%	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	26.5%	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	5.5%	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-6.7%	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	-14.4%	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-11.5%	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-15.7%	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	50.7%	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	25.1%	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	0.3%	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0
AECO	5 mo back	Nov 98 - Mar 99 Fcst	-5.2%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-5.8%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	35.3%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	-11.5%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	14.1%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	12.7%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-3.6%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	-3.1%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-6.7%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-12.4%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	51.8%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	15.6%	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

		Nov 96 - Mar 97 Fcst	35.3%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	-11.5%	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	14.1%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	12.7%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-3.6%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 95 Fcst	-3.1%	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-6.7%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-12.4%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	51.8%	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	15.6%	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	3.8%	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
AECO	6 mo back	Nov 98 - Mar 99 Fcst	-1.2%	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-21.8%	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	34.6%	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	-7.5%	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	12.9%	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	19.8%	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-9.1%	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-5.3%	1	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-13.3%	1	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	50.0%	1	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	14.0%	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	9.0%	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
AECO	7 mo back	Nov 98 - Mar 99 Fcst	-2.5%	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-13.1%	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	26.[illegible]	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	0.3%	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		AECO Apr-Oct 98 Fcst	12.4%	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		AECO Apr-Oct 97 Fcst	21.6%	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		AECO Apr-Oct 96 Fcst	-8.2%	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-8.1%	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-7.1%	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	48.1%	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Apr-Oct 98 Fcst	12.9%	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
		Apr-Oct 97 Fcst	13.2%	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
AECO	8 mo back	Nov 98 - Mar 99 Fcst	1.7%	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	2.1%	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	21.8%	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	7.0%	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Apr-Oct 98 Fcst	14.5%	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Apr-Oct 97 Fcst	17.9%	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Apr-Oct 96 Fcst	-9.3%	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	-2.4%	1	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-2.9%	1	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	44.7%	1	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Apr-Oct 98 Fcst	13.2%	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
		Apr-Oct 97 Fcst	10.2%	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
AECO	9 mo back	Nov 98 - Mar 99 Fcst	8.2%	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-4.1%	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Nov 96 - Mar 97 Fcst	21.3%	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Nov 95 - Mar 96 Fcst	13.5%	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Apr-Oct 98 Fcst	13.8%	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Apr-Oct 97 Fcst	18.9%	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Apr-Oct 96 Fcst	-10.2%	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	0.9%	1	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Nov 97 - Mar 98 Fcst	-2.9%	1	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Apr-Oct 98 Fcst	9.7%	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0
		Apr-Oct 97 Fcst	15.2%	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0
AECO	10 mo back	Nov 98 - Mar 99 Fcst	15.3%	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Nov 97 - Mar 98 Fcst	-4.0%	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Nov 95 - Mar 96 Fcst	1.4%	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Apr-Oct 98 Fcst	14.1%	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Apr-Oct 97 Fcst	19.3%	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Apr-Oct 96 Fcst	-23.9%	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	2.7%	1	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Nov 97 - Mar 98 Fcst	-18.8%	1	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Apr-Oct 98 Fcst	10.0%	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0
		Apr-Oct 97 Fcst	20.8%	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0
AECO	11 mo back	Nov 98 - Mar 99 Fcst	19.8%	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Nov 97 - Mar 98 Fcst	-4.8%	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Nov 95 - Mar 96 Fcst	-15.7%	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Apr-Oct 98 Fcst	10.5%	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Apr-Oct 97 Fcst	18.1%	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
Sumas		Nov 98 - Mar 99 Fcst	7.5%	1	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Apr-Oct 98 Fcst	9.4%	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0
		Apr-Oct 97 Fcst	15.2%	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0
AECO	12 mo back	Nov 98 - Mar 99 Fcst	15.7%	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Nov 97 - Mar 98 Fcst	4.1%	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Nov 95 - [illegible] 96 Fcst	-28.1%	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Apr-Oct 98 Fcst	12.5%	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
Sumas		Nov 98 - Mar 99 Fcst	-13.7%	1	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Nov 97 - Mar 98 Fcst	-7.6%	1	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Apr-Oct 98 Fcst	10.0%	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0
		Apr-Oct 97 Fcst	7.4%	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0
AECO	13 mo back	Nov 98 - Mar 99 Fcst	16.7%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
		Nov 97 - Mar 98 Fcst	12.3%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
		Apr-Oct 98 Fcst	20.2%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
AECO	14 mo back	Nov 98 - Mar 99 Fcst	17.7%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
		Apr-Oct 98 Fcst	16.2%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1