PRICE DISCOVERY IN THE NATURAL GAS MARKETS

OF THE UNITED STATES AND CANADA

A Thesis

by

KYLE OLSEN

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2010

Major Subject: Agricultural Economics

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	David A. Bessler
Committee Member,	Steven L. Puller
Head of Department,	John P. Nichols

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ABSTRACT

Price Discovery in the Natural Gas Markets of the United States and Canada.

(December 2010)

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Co-Chairs of Committee: Dr. James W. Mjelde
Dr. David A. Bessler

The dynamics of the U.S. and Canada natural gas spot markets are evolving through deregulation policies and technological advances. Economic theory suggests that these markets will be integrated. The key question is the extent of integration among the markets. This thesis characterizes the degree of dynamic integration among 11 major natural gas markets, six from the U.S. and five from Canada, and determines each individual markets' role in price discovery. This is the first study to include numerous Canadian markets in a North American natural gas market study.

Causal flows modeling using directed acyclic graphs in conjunction with time series analysis are used to explain the relationships among the markets. Daily gas price data from 1994 to 2009 are used. The 11 natural gas market prices are tied together with nine long-run co-integrating relationships. All markets are included in the co-integration space, providing evidence the markets are integrated. Results show the degree of integration varies by region. Further results indicate no clear price leader exists among the 11 markets. Dawn market is exogenous in contemporaneous time, while Sumas market is an information sink. Henry Hub plays a significant role in the price discovery

of markets in the U.S. Midwest and Northeast, but little to markets in the west. The uncertainty of a markets' price depends primarily on markets located in nearby regions.

Policy makers may use information on market integration for important policy matters in efforts of attaining efficiency. Gas traders benefit from knowing the price discovery relationships.

DEDICATION

I dedicate this thesis to my wife Rachel, as well as to our two wonderful daughters.

ACKNOWLEDGEMENTS

First and foremost, I am most grateful to Dr. James W. Mjelde, the co-chair of my advisory committee, who first introduced me to the ideas and methods that enabled this research. I thank him for allowing me the opportunity to work on such a project and for his consistent guidance, support, and encouragement along the way. His mentoring and guidance made my introduction to research a pleasant experience. I am particularly grateful for his prompt feedback and dependability when it came to asking questions on numerous occasions. Clearly, this thesis would not have been possible without his help.

Special recognition and thanks go to Dr. David A. Bessler, co-chair of my advisory committee, whose advice and vast knowledge kept me going in the right direction throughout the completion of this thesis. I am grateful to Dr. Bessler for his time and effort as he entertained concerns that arose during the course of this research. I would like to extend an appreciation to committee member Dr. Steven L. Puller for his willingness to serve on my committee and for his time.

Thanks also go to my colleagues and the department faculty and staff for making my time at Texas A&M University a great experience. I also want to express my gratitude to the many anonymous people who have contributed immeasurable amounts of encouragement, support, and wisdom throughout my life, without which I wouldn’t be where I am today. Lastly, special thanks go to my mother and father for their belief in me and to my wife for her patience and love.

NOMENCLATURE

AECO	AECO C Spot, Alberta, Canada
CH	Chicago Citygate, Illinois, United States
DAGs	directed acyclical graphs
DAWN	Dawn, Ontario, Canada
EMPR	Empress Spot, Alberta, Canada
FEVDs	forecast error variance decompositions
HH	Henry Hub, Louisiana, United States
IRFs	impulse response functions
IROQ	Iroquois, New York, United States
KING	Kingsgate, British Columbia, Canada
MALI	Malin, Oregon, United States
NIAG	Niagara, Ontario, Canada
NY	Transco Z6 NY, New York, United States
SUMA	Sumas, Washington, United States
VAR	vector autoregression
VECM	vector error correction model

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CHAPTER 1

INTRODUCTION

The dynamics of the U.S. and Canada natural gas spot markets are evolving because of technological advances and deregulation policies. Economic theory suggests that deregulated markets will be integrated (DeVany and Walls 1995). The key question is the extent of integration among the markets. Under regulation policies prior to 1970's, natural gas spot market pricing was partially set by market regulators. One goal of deregulation policies was to let the buyers and sellers discover price, hence, increasing the role of the spot markets (FERC 1992). The North America Energy Working Group (2002) states that the unbundling of marketing, transmission, and distributions services created opportunities for buying and selling natural gas (trading, hedging, contracts, transporting, etc.). If deregulation has been effective then the "law of one price" should hold; meaning prices at different market hubs should be the same after taking into account transportation and other transaction costs. Some discrepancies in prices as a result of transportation / transaction costs from one region to another are expected. Further, one would expect that following deregulation policy and technological advances, adaptation or learning by market participants would result in a more efficient market environment.

This thesis follows the style of the *American Journal of Agricultural Economics.*

Another goal of deregulation in the energy markets is to increase market efficiency by enhancing competition. As a result of deregulation, more competitive and interrelated market environments are developing in the natural gas markets of North America (Park, Mjelde, and Bessler 2007, 2008). These changes imply that price determination is more likely to be in the hands of the market participants than in the regulators' hands. The extent of natural gas market integration has some important practical implications. Producer access to market opportunities, consumer access to least-cost supplies, and the price determination process all depend on the extent to which regional natural gas markets are linked (King and Cuc 1996).

Objectives

This study's objective is to analyze the efficiency of gas markets in response to price signals, by characterizing the extent of dynamic integration among markets and by investigating each individual markets' role in price discovery. Previous studies of North American gas markets used primarily U.S. markets usually including only one or two Canada markets; here, a balance is given between five Canada and six U.S. markets to produce a more in-depth analysis of the North American market including integration among U.S. and Canada natural gas markets. The degree of integration in the natural gas market will indicate if the markets are achieving the goal of the "law of one price." Further, this data is daily data ranging over 15 years, whereas, other similar studies' data ranged only three to seven years with some using monthly data.

To achieve this study's objective economic analysis of the relationships among 11 natural gas spot markets is conducted. A vector error correction model (VECM) combined with directed acyclical graphs (DAGs) forms the basis for determining the dynamic relationships among the 11 markets. The analysis provides the contemporaneous causality among Canadian and U.S. natural gas markets. This causality relationship determines which markets are price leaders, and which are information sinks. Sinks do not contribute to any natural gas price determination, in contemporaneous time. Further, usual innovation accounting analysis consisting of impulse response functions (IRFs) and forecast error variance decomposition (FEVDs) from the estimated VECM provide the dynamic relationships among the markets.

Innovation accounting illustrates the dynamic or ripple effects among the 11 natural gas spot markets from a shock in a particular market. The transmission of a shock in natural gas prices of one region to another region with possible time lags is referred to as the ripple effect. This study, therefore, provides a dynamic picture of daily price information flow among 11 U.S. and Canada natural gas spot markets for the years 1994 – 2009.

CHAPTER II

LITERATURE REVIEW AND BACKGROUND

Market prices fluctuate over time responding to numerous factors. The goal of many studies has been to accurately forecast and/or explain economic markets' behavior. It is important before developing an economic model to understand the market structure and how to organize its' characteristics to achieve the study's objectives. Stock (2002) states perfect forecasts are not achievable, because of unanticipated information such as policy, weather, or technology. It, however, has been noted that endogenous dynamics are measurable and even expected under certain estimation systems (Stock 2002).

Conopask (2002) notes factors contributing to the outlook of the natural gas market prices include storage, weather, economic conditions, production and drilling, and national security. Storage by both utility and production companies plays an important role in the short-run supply of natural gas. Shocks from weather in the short-run can be greatly reduced if there is a large amount of stored natural gas. Weather variations have an obvious effect on natural gas prices. According to U.S. Department of Energy (U.S. Department of Energy (U.S.DOE), 2003), natural gas demand during winter months is more than 1.5 times daily winter production. If future winter temperatures are expected to fall, natural gas prices will likely experience upward pressure (Conopask 2002). During hurricane seasons natural gas producing regions are affected causing shortages of natural gas restricting trade and increasing prices (U.S. DOE 2009a).

Studies on market integration have found conflicting results. Cuddington and Wang (2006) and King and Cuc (1996) show there exists an east-west split among the North American gas markets, whereas, Serletis (1997) did not find such a split. Park, Mjelde, and Bessler (2008) report that the Canadian and U.S. natural gas market is a highly integrated market. Results from Park, Mjelde, and Bessler (2008) indicate that price discovery tends to reflect both regions of excess demand and supply. Further, their study, consisting of seven U.S. markets and one Canada market, reports Malin Hub, Oregon; Chicago Hub, Illinois; Waha Hub, Texas; and Henry Hub, Louisiana are the main markets for price discovery. Seasonal differences are found in the long-run relationships because the exogenous variables, heating degree-days and cooling degree-days are included in the co-integrating vectors. Besides industrial use, natural gas is used for residential and commercial heating and electricity generation. Because natural gas is used for heating and electricity generation in the winter and electricity generation in the summer Park, Mjelde, and Bessler (2008) conclude seasonality is plausible.

Demand and prices for natural gas have normally been highest in the winter, because of the need for heating by the residential and commercial sectors. The National Energy Board (2002) states that natural gas transmission and delivery systems are designed to meet peak demand requirements which usually occur in winter. Daily consumption during the winter in the combined residential and commercial sectors can be nearly double the annual average consumption on a per-day basis (U.S. DOE 2001). Further, in recent years, natural gas demand has increased in the summer, as more gas is used for electricity generation, to meet cooling needs (U.S. DOE 2009a).

Park, Mjelde, and Bessler (2007) found that markets that can be characterized as excess producing markets tend to have higher mean price differences in a threshold co-integrating model relative to excess consuming markets during the summer. They also note that excess consuming markets tend to have an opposite seasonal pattern; mean price differences are higher in winter.

Some previous gas market studies have used monthly data (King and Cuc 1996, Kleit 1998, Spulber and Doane 1994). The use of daily data provides a much more detailed look at market dynamics in an era where an extensive set of spot markets have evolved. This is an important consideration. Taylor (2001) shows underestimation of speeds of market adjustment may occur when using data of lower frequency than that of the actual market transactions.

Natural gas markets in Canada developed as natural gas was transformed from a low-value byproduct of oil production to a valuable commodity (U.S. DOE 2000). Natural gas became increasingly more valuable as a vast pipeline network was built and the forming of the Canadian National Energy Board in the 1950's. These changes marked the beginning of the major development of the domestic and international markets. Canadian natural gas market structure began as one of a single buyer, transporter, and seller of natural gas (Booth 2003). Canadian government in 1985 agreed to regulatory reforms that altered the structure of the Canadian natural gas industry. Two major policies, the Western Accord and the Agreement on Natural Gas Markets and Prices, allowed the Canadian Federal Government and Canada's western natural gas producing provinces of Alberta, British Columbia, and Saskatchewan, to eliminate all forms of price regulation of natural gas and oil (National Energy Board 1988). These agreements also provided for enhanced access to export markets by relaxing natural gas export regulations. Under the new regulatory procedures, exports of Canadian natural gas to the U.S. nearly quadrupled between 1986 and 1994. The National Energy Board (1997 p. 3) states, "Among other things, deregulation allowed producers to sell gas directly to end-users at freely-negotiated prices, and also provided producers with open access to gas transportation services."

Reforms in the Canadian natural gas markets during the 1980's were in response to the 1970's oil crisis. Changes to natural gas price regulations broke up integrated monopolies into separate marketing, transmission, and distribution service companies (North America Energy Working Group 2002). Production deregulation and open access to pipelines in natural gas industry allowed market centers and hubs to develop which provided various services such as loaning, storage, electronic trading and title transferring (U.S. DOE 1995). These centers and hubs serve as natural gas spot markets. Centers and hubs are located at intersections of major pipeline systems and within major producing regions. In addition to multiple pipeline interconnections, market centers and hubs usually have access to natural gas storage facilities, which enhance the trading options of buyers and sellers (National Energy Board 2002).

In the U.S., natural gas regulation began with The 1938 Natural Gas Act (U.S. DOE 2009b). This Act gave the Federal Power Commission, now the Federal Energy Regulatory Commission, authority to regulate natural gas interstate commerce. A U.S. Supreme Court decision in 1954, Philips Petroleum Co. vs. Wisconsin, forced the Federal Power Commission to extend price controls to producers. Policy regulations culminated in the natural gas shortages of the 1970's (U.S. DOE 2009b). In response to the shortages, The Natural Gas Policy Act of 1978 was passed, beginning the framework for the regulation of the natural gas industry today (U.S. DOE 2009b). The repeal of the Power Plant and Industrial Fuel Use Act of 1987 and The Natural Gas Wellhead Decontrol Act of 1989 reduced restrictions on the use of natural gas (U.S. DOE 2009b). Both Acts were designed to facilitate the eventual complete price deregulation of the interstate natural gas market. Further, FERC orders (Order 380 issued in 1984 and Order 636 issued in 1992) provided large industrial consumers, electric utilities, and local distribution companies' opportunities to buy lower-priced natural gas and make alternative transportation agreements (U.S. DOE 2009b). These Orders also required interstate pipeline companies to unbundle their distribution, sales, and storage services. FERC Order 636 was updated in 2000 through FERC Order 637 (U.S. DOE 2009b), in attempt to update gas pipeline operations and increase the level of transparency.

As deregulation broke up vertically integrated gas production, delivery, and marketing, consuming regions began demanding additional pipeline capacity. Without additional pipelines consumers would still be limited in their access to natural gas. As a consequence of increased pipeline demand significant expansions at many of the market

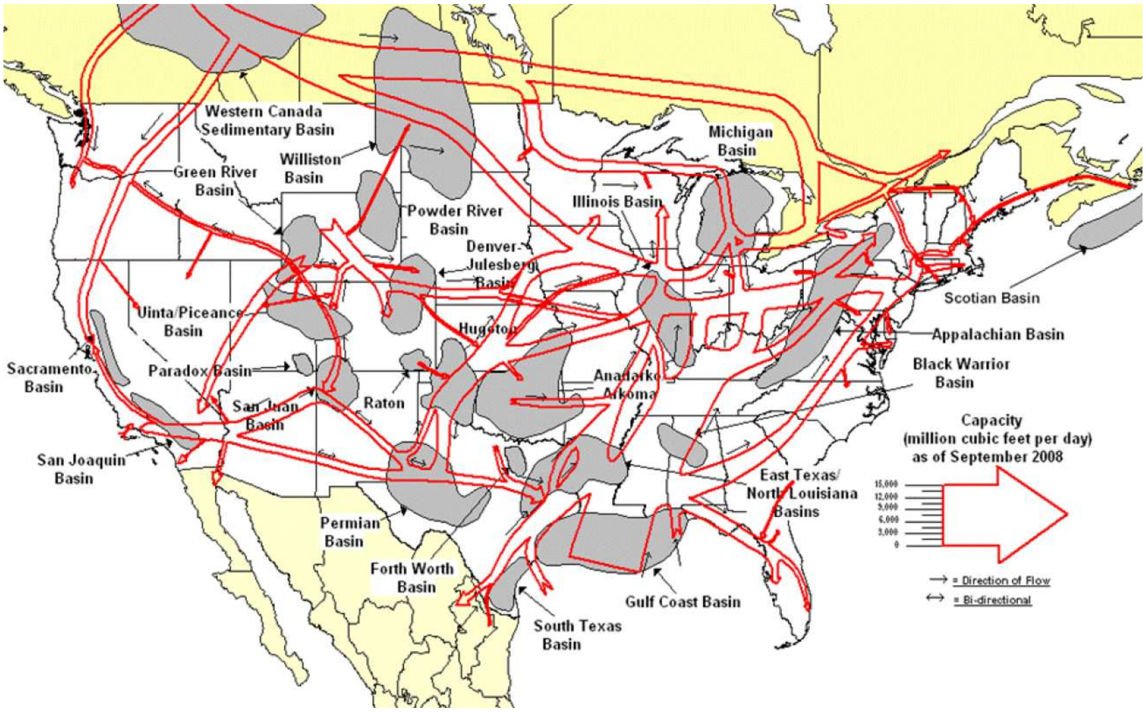


Figure 2.1. U.S. and Canada natural gas supply basins relative to major natural gas pipeline transportation corridors in 2008. Source: U.S. DOE 2008.

centers have occurred in both the U.S. and Canada. Between 2003 and 2008, estimates indicate that transportation activities at U.S. market centers increased on average approximately 39 percent, with at least 16 of the 24 U.S. market centers showing an increase in average daily throughput activity of 10 percent or more (U.S. DOE 2009c). Average daily volume of natural gas transported by individual pipelines on the entire U.S. interstate network in 2007 was about 101 billion cubic feet per day (Bcf/d). Estimates of average daily volumes in 2003 were approximately 25 percent of that figure or about 25 Bcf/d (U.S. DOE 2009b). See Figure 2.1 for location of U.S. and Canada natural gas producing regions as they relate to major transportation corridors.

Six of the nine market centers currently in operation in Canada are located in the Province of Alberta, which dominates Canadian gas production. The centers have had no appreciation in estimated average daily throughput since 2003 (U.S. DOE 2009c). One of the principal reasons for this static condition is TransCanada Pipeline's mainline system, the primary delivery interconnection, has actually decreased its overall system capacity between the Alberta border and eastern Canada because of lower shipper demand (U.S. DOE 2009c). Dawn Market Center was the only market to report an increase in daily average throughput of 86 percent, more than doubling it's interconnect capacity by adding one additional pipeline interconnection (U.S. DOE 2009c). Sumas Market Center reported a negative 17 percent change in throughput simultaneously reporting a 12 percent increase in interconnect capacity. Overall 33 market centers in the U.S. and Canada were operating in 2008 (U.S. DOE 2009c), nine in Canada and twenty-four in the United States. The number of operational centers has remained essentially the same since the late 1990's (U.S. DOE 2009c).

CHAPTER III

DATA DESCRIPTION AND METHODOLOGY

Descriptions of the data used in the analysis along with exogenous variables considered are given in the Data and Variable Specification section. Methods used to specify the dynamics of the 11 U.S. and Canada natural gas markets are presented in the Methodology section. Further, hypothesis testing is explained in the Post-Estimation and Procedures followed by formation of the VAR used to conduct innovative accounting.

Data and Variable Specification

Eleven daily natural gas spot market price series from Canada and the U.S. are included in the analysis. Previous studies have concentrated on U.S. market integration, as such, more U.S. markets than Canada markets were included in their analysis. This study uses five natural gas spot market price series from Canada and six from the U.S. to further determine the degree of integration and price dynamics among the two countries' markets. Regional dispersion and data availability are two main factors in determining which markets to include. Niagara, Ontario; Dawn, Ontario; AECO, Alberta; Empress Spot, Alberta; and Kingsgate, British Columbia are the five Canadian markets included (Figure 3.1). The Canada markets are spread from east to west with no market located in the central region. No data was available for this region.

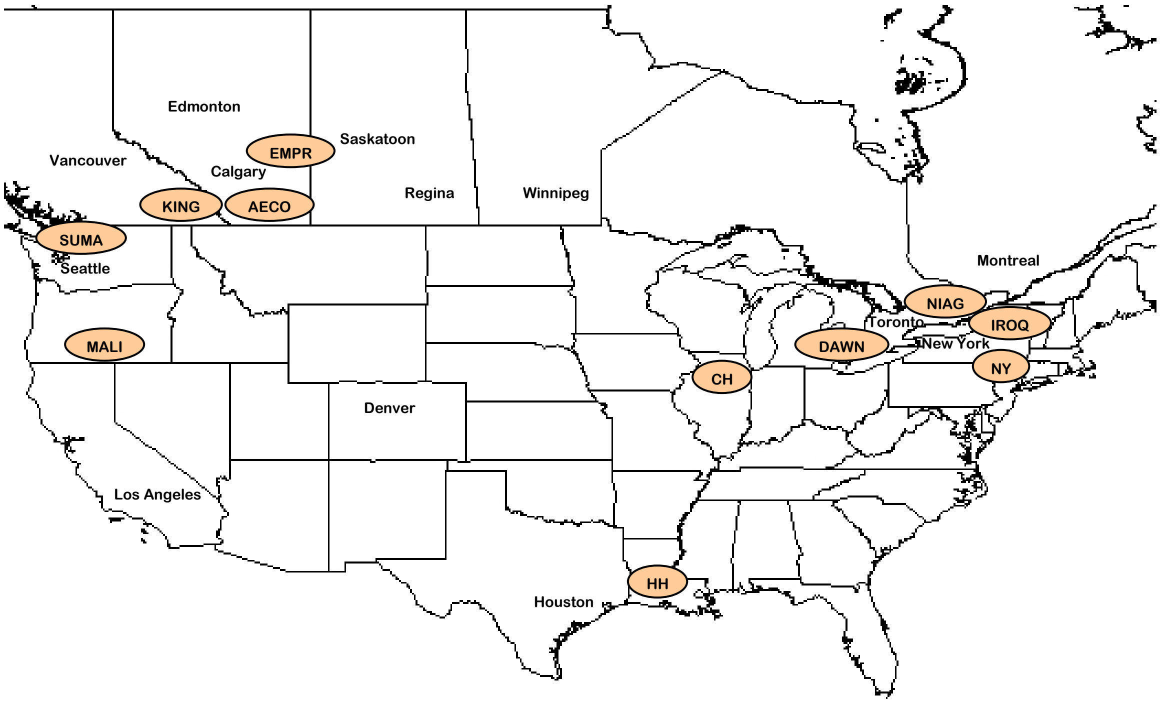


Figure 3.1. Approximate locations of the 11 natural gas markets in the U.S. and Canada, and the 13 cities used to obtain aggregate heating and cooling degree days. The markets from west to east are Sumas, Washington (SUMA); Malin, Oregon (MALI); Kingsgate, British Columbia (KING); AECO, Alberta (AECO); Empress, Alberta (EMPR); Henry Hub, Louisiana (HH); Chicago Citygate, Illinois (CH); Dawn, Ontario (DAWN); Niagara, Ontario (NIAG); Iroquois, New York (IROQ); and New York Zone 6 NY, New York (NY).

The six U.S. markets are: Henry Hub, Louisiana; Chicago Citygate, Illinois; Transco Zone 6 NY, New York; Iroquois, New York; Sumas, Washington and Malin, Oregon (Figure 3.1). Park, Mjelde, and Bessler (2008) show Henry Hub and Chicago are important players in the U.S. market. The two New York markets represent the northeastern U.S. market and Malin represents the western U.S. market.

Daily natural gas prices, provided by Bloomberg L.P. (2009), include the days March 11, 1994 through March 25, 2009 (Table 3.1 and Figure 3.2). Major deregulation policies in both countries had been enacted before the beginning of the data

Table 3.1. Descriptive Statistics on 11 U.S. and Canada Non-Logged Natural Gas Market Prices, Heating and Cooling Degree Days, and Canadian to U.S. Dollar Exchange Rate, Daily Data March 11, 1994–March 25, 2009.

Series	Daily Average	Standard Deviation	Minimum (Date)	Maximum (Date)
Henry Hub[a]	4.54	2.71	1.03 (12/04/1998)	19.38 (02/25/2003)
Chicago	4.55	2.64	1.23 (12/04/1998)	23.00 (02/02/1996)
New York	5.36	3.61	1.34 (12/04/1998)	55.00 (01/14/2004)
Malin	4.22	2.97	0.93 (02/27/1995)	56.25 (12/08/2000)
Iroquois	4.89	2.95	1.08 (12/04/1998)	43.00 (01/14/2004)
Niagara	5.83	2.92	1.54 (12/04/1998)	29.04 (02/25/2003)
Dawn	5.72	2.83	1.65 (10/07/1994)	27.62 (02/25/2003)
Empress	4.54	2.70	0.80 (10/03/1997)	14.89 (12/11/2000)
AECO	4.44	2.69	0.65 (10/03/1997)	16.95 (12/11/2000)
Kingsgate	4.75	3.28	0.88 (01/23/1995)	58.29 (12/08/2000)
Sumas	4.79	3.26	0.94 (07/25/1995)	58.28 (12/08/2000)
Canada HDD[b]	22.38	17.48	0.00	70.31 (01/5/1996
Canada CDD	1.65	3.71	0.00	28.87 (08/5/2003)
U.S. HDD	10.00	9.42	0.00	37.28 (12/22/2008)
U.S. CDD	3.23	3.97	0.00	17.35 (08/01/2006)
Exchange Rate	0.75	0.10	0.62 (01/18/2002)	1.09 (11/06/2007)

a) The 11 price series' daily average values are in terms of U.S. dollars.
b) The Canada and U.S. HDD and CDD average values are in terms of degrees Fahrenheit.

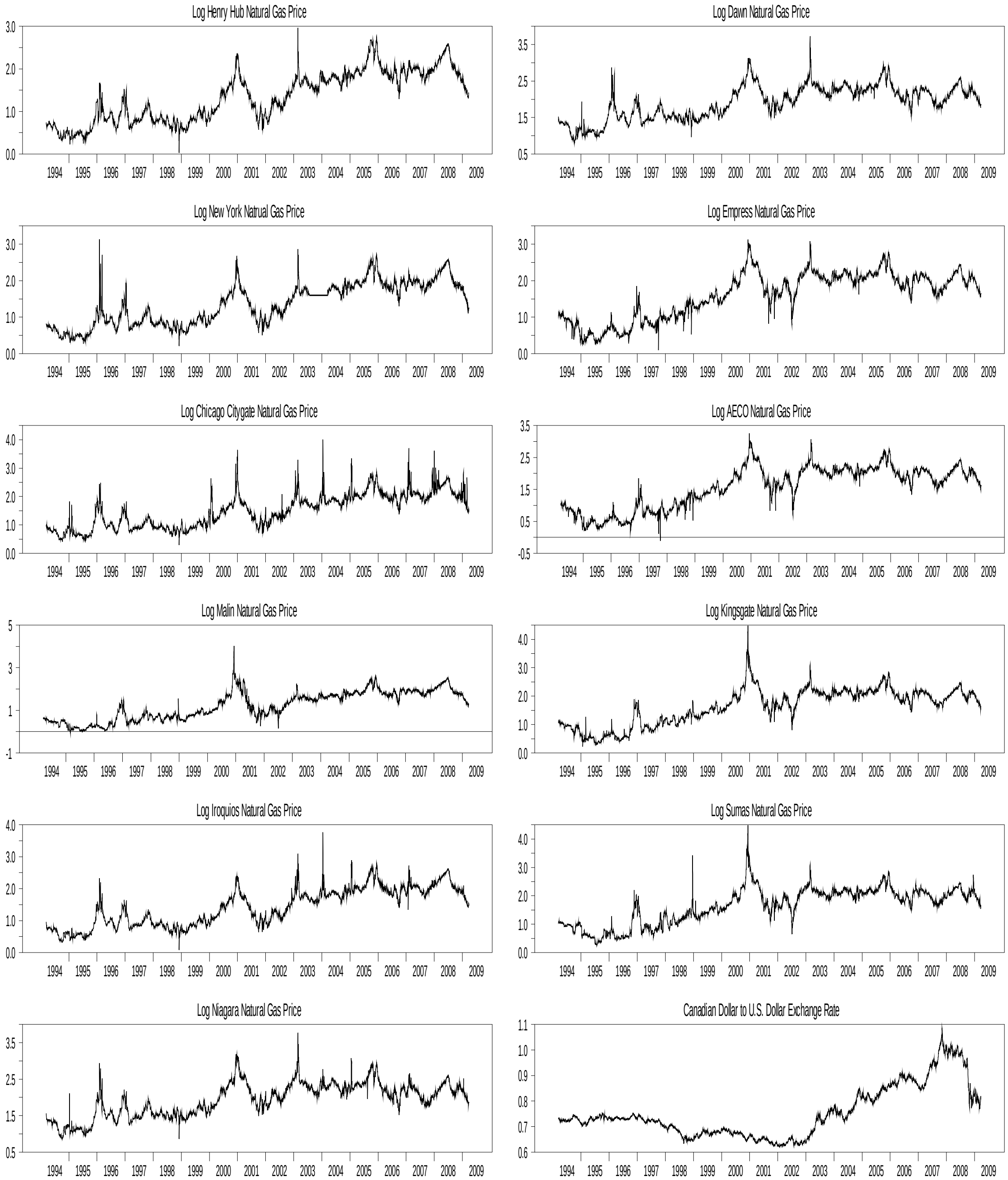


Figure 3.2. Plots of logarithms of prices of 11 U.S. and Canada natural gas markets and a Canada to U.S. dollar exchange rate. Prices are expressed in \$/MMbtu, daily data March 11, 1994–March 25, 2009.

set in 1994. Prices are the last price at close of each trading day. Five days per week are considered as trading days, Monday, Tuesday, Wednesday, Thursday, and Friday. This weekday trading scheme is maintained in the data set, even if a holiday occurred during a given week. Most missing values occur because of holidays. Missing values occurring because of holidays are replaced by the previous day's price, maintaining the five day trading week. Price data from Energy Information Administration weekly report (U.S. DOE 2009d) was used to fill in periods of missing data that lasted more than a week in three of the U.S. markets, Henry Hub, Chicago, and New York. Other missing values are replaced by the previous days' price. Where missing price data occurred for more than a week, it was often because of an extreme weather event, such as a hurricane, affecting a particular hub. Other times the reason for missing price data from the Bloomberg portal is unknown.

U.S. natural gas market prices given by Bloomberg L.P. are listed in U.S. dollars, whereas, Canadian gas market prices are in Canadian dollars. Daily exchange rates from Bloomberg L.P. are used to convert Canadian dollars to U.S. dollars before the empirical analysis. One hundred and forty missing values existed in the exchange rate data. Missing exchange rate values are replaced using values from Federal Reserve Bank of St. Louis (2009); if the Federal Reserve Bank of St. Louis did not have the missing values an average exchange rate value of the day before and after was used.

Aggregate heating and cooling degree days for the U.S. are computed using average daily temperatures (National Oceanic and Atmospheric Administration 2009) from

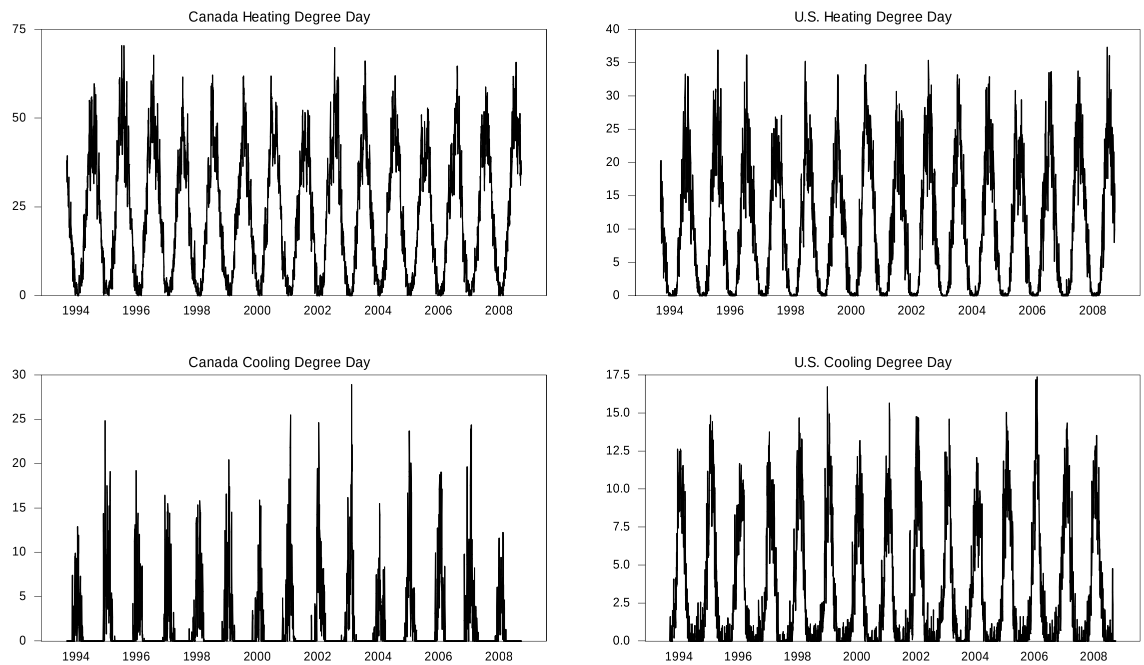


Figure 3.3. Plots of cooling and heating degree days in the U.S. and Canada, daily data March 11, 1994–March 25, 2009.

five major cities across the U.S., New York, Houston, Denver, Los Angeles, and Seattle (Figures 3.1 and 3.3). Canadian aggregate heating and cooling degree days are computed using average daily temperatures (National Oceanic and Atmospheric Administration 2009) from eight major cities across Canada, Montreal, Toronto, Winnipeg, Regina, Saskatoon, Edmonton, Calgary, and Vancouver (Figures 3.1 and 3.3). A temperature of 65 degrees Fahrenheit is used as the base temperature for calculating both cooling and heating degree days. Formulas used to calculate HDD and CDD are:

$$CDD_{ij} = (Avg.Temp_{ij} - 65), \text{ if } CDD_{ij} < 0 \text{ then } CDD_{ij} = 0; \quad (1)$$

$$CDD_j = \sum_i [(CDD_{ij} * Population_i) / Total\ Population\ of\ all\ i's]; \quad (2)$$

$$HDD_{ij} = (65 - Avg.Temp_{ij}),\ if\ HDD_{ij} < 0\ then\ HDD_{ij} = 0;\ and \quad (3)$$

$$HDD_j = \sum_i [(HDD_{ij} * Population_i) / Total\ Population\ of\ all\ i's]; \quad (4)$$

where i indicates the city and j indicates the day. $Avg.Temp_{ij}$ is the average of the high and low for city i and day j, $Population_i$ is the population for city i. Population values for the eight Canada cities are from Canada By Map (2009). Population values for the five U.S. cities are from United States Census Bureau (2003).

Two other sets of exogenous variables, trading day and seasonality, are considered when determining the best model for the VECM. Five dummy variables for trading day, one for each trading day of the work week, Monday through Friday are considered. Seasonality enters into the model as a series of four dummy variables, one variable for each season of the year, winter, spring, summer, and fall. To avoid perfect collinearity, Friday and fall are dropped in the estimation.

Methodology

Economic price data are usually non-stationary (Samuelson 1971), meaning prices have a trend and over time they are not tied to their historical mean. Further, the economic theory of the law of one price suggests that natural gas markets are not independent of one another. Dependence implies if economic forces influence one market, the same forces are expected to influence all markets. The influence of the force on each of the natural gas market prices or price movements, however, does not have to be identical across markets. Suppose the difference between prices at two different markets increases, market participants involved in arbitrage activities would drive the prices back together (assuming natural gas is a homogenous good). Large deviations in market price, therefore, are not expected to continue; the price difference has a tendency to return to its mean value.

One way to characterize the theory that price differences will not deviate for long periods from transaction and transportation costs between the markets is assuming there exists a long-run relationship between the markets. To clarify consider two markets whose prices, *P1* and *P2*, are non-stationary or integrated of order one, *I(1)*, let the long-run relationship be given by $P1_t = \mu + P2_t + e_t$ where μ denotes the expected value of the price difference (transaction and transportation costs) between markets, e_t is a zero mean, stationary process or *I(0)*, and t is time (Kennedy 2008). The equilibrium occurs when $e_t = 0$. There, however, may be deviations from equilibrium at any point in time t, $(e_t \neq 0)$, but such deviations are temporary. If this long-run relationship is the case, then the price series are said to be cointegrated. An amusing example from Murry (1994) presents this idea as a drunk walking her dog. The drunk and the dog, attached by a leash, wonder all night aimlessly, during which time the dog because of the leash will never stray too far from its owner. On the next day there is no telling where the two will end up, but it is certain that where you find the one the other will be also. The economic interpretation of cointegration is the concept of an attractor or of long-run equilibrium between two or more stochastic processes. Two or more stochastic processes are allowed to diverge in the short-run, but in the long-run they converge to a common region or attractor region given there are no new shocks to the system.

The data generating process for a vector of prices, which is cointegrated, can be expressed as a vector error correction model (VECM). The basis for VECM analysis is vector autoregression (VAR) analysis. Vector autoregression is widely used in macroeconomic analysis. Juselius (2006 p. 14) states "There are many reasons for this: the VAR model is flexible, easy to estimate, and usually gives a good fit to macroeconomic data." Further, and quite possibly the most important reason why VAR models are used, is their ability to capture long-run and short-run information in the data (Juselius 2006).

A VAR can include a generous lag structure and allow for inclusion of exogenous variables. Both the number of lags and exogenous variables to include are determined by testing procedures. After determining the appropriate number of lags and exogenous variables to include in the VAR model, the VAR can be transformed to a VECM. This produces a term that represents the extent to which long-run equilibrium is not met, called the error correction term. The VECM framework provides a formal model that can be used to test for and estimate long-run, short-run, and contemporaneous relationships among natural gas market prices. Further, because all market prices can be included in each individual equation within the VECM, each market's equation accounts for supply and demand conditions of not only its own market but also in all the other markets.

Consider the VAR equation, which forms the basis of the analysis of the 11 natural gas markets:

$$P_t = \mu + \beta_1 P_{t-1} + \ldots + \beta_k P_{t-k} + \Psi Z_t + e_t;\ (t = 1,\ldots, T), \tag{5}$$

where, P_t denotes a (11 x 1) vector that includes 11 non-stationary prices at time t, μ is a (11 x 1) vector of constant terms, β is a (11 x 11) matrix of coefficients relating lagged levels of prices to current prices, Ψ is a (11 x g) coefficient matrix associated with the (g x 1) vector of g possible exogenous variables (Chapter IV shows g is equal to 8) at time t included in the model denoted by Z_t, and e_t is a (11x1) vector of error terms. After algebraic manipulation the VAR becomes a VECM with k-1 lags (Hansen and Juselius 1995):

$$\Delta P_t = \mu + \prod P_{t-1} + \sum_{i=1}^{k-1} \Gamma_i \Delta P_{t-i} + \Psi Z_t + e_t;\ (t = 1,\ldots, T), \tag{6}$$

$$e_t \sim N\ iid\ (0,\Sigma),$$

where Δ is the difference operator ($\Delta P_t = P_t - P_{t-1}$), P_t, μ, Z_t, and Ψ are as defined earlier, $\prod$ (equal to $\alpha\beta'$) is a (11x11) matrix of coefficients relating lagged levels of prices (not changes) to current changes in prices, Γ_i is a (11x11) matrix of short-run coefficients relating lagged period i price changes to current changes in prices, e_t is a (11x1) vector of random disturbances or innovations reflecting new information emanating from (discovered in) each of the ten series, *Niid* means that e_t follows a normal independent and identical distribution with mean zero and variance Σ.

The number of cointegration relations, or rank of $\prod$ denoted by r, provides information on the long-run structure between the markets. The long-run structure among the markets is further understood through testing hypotheses on β. Similarly, the short-run structure is studied through testing hypotheses on α (Juselius 2006). The contemporaneous structure is summarized through analysis of the covariance matrix of observed innovations given by Σ from equation 6.

Post-Estimation and Procedures

When analyzing the VAR model, it is sometimes the case that only subsets of the variables in the P_t vector are in the cointegration space (Hansen and Juselius 1995). Tests of exclusion are performed to determine if some markets are excluded in all of the identified long-run relations. The null hypothesis of this test is that series i is not in the cointegrating space. Under the null, the likelihood ratio test statistic is distributed chi-squared with degrees of freedom equal to the number of zero restrictions associated with each cointegrating vector (Juselius 2006), is expressed as:

$$H_1 : R'\beta = 0, \tag{7}$$

where R' is a design matrix of zeros and ones placed to exclude various markets from the cointegration space. Tests of exclusion determine which exogenous variables are included in the long-run relationships.

Tests of weak exogeneity are used to determine whether prices are unresponsive in the short-run to the deviations from the long-run relationships. This is accomplished by testing α which is the parameter that defines the short-run adjustments to perturbations in the long-run relationships. The null hypothesis is that series *i* does not respond to perturbations in the long-run relationships. The likelihood ratio test statistic under the null is distributed chi-squared with degrees of freedom equal to the number of cointegrating vectors (Juselius 2006), is:

$$H_1: B'\alpha = 0 \tag{8}$$

where, B is a design matrix similar to R for expressing each particular hypothesis.

To conduct innovative accounting, the estimated VECM is re-expressed as levels VAR by simple algebraic manipulation of the parameters:

$$P_t = \mu + (I + \prod + \Gamma_1)\, P_{t-1} - \sum_{i=1}^{k-2} (\Gamma_i - \Gamma_{i+1}) P_{t-i-1} - \Gamma_{k-1} P_{t-k} + \Psi Z_t + e_t;\ (t = 1, \ldots, T),$$

$$e_t \sim N\ iid\ (0, \Sigma). \tag{9}$$

For meaningful innovative accounting, the contemporaneous structure of the error terms must be independent (orthogonal), which is usually not the case with economic data. Sims (1980) notes that because the covariance matrix is not diagonal, it is not possible to shock the individual equations of the system independently to trace out impulse responses, or to calculate forecast error variance decompositions. He suggests working with orthogonalizing transformations of the VAR to secure a one-to-one correspondence between shocks and equations. Further if innovations are contemporaneously correlated, it is misleading to examine a shock to a single variable in isolation (Doan 2007). One way of addressing this issue is an ordering procedure suggested by Bernanke (1986) to transform the VAR. In this ordering transformation, innovations are written as a function of more fundamental driving sources of variations, ε_t, which are orthogonal of other sources of variation. In other words premultiplying each member of (9) by a matrix (A) which is orthogonal so that the covariance matrix of transformed residuals is orthogonal:

$$e_t = A^{-1}\varepsilon_t, \tag{10}$$

where A is a matrix representing how the non-orthogonal innovations, e_t, are caused by the orthogonal variation in each equation (Bernanke 1986). Before usual innovation accounting procedures are carried out the VAR from equation (9) is pre-multiplied by A:

$$AP_t = A\mu + A(1 + \prod + \Gamma_1)\, P_{t-1} - A\sum_{i=1}^{k-2}(\Gamma_i - \Gamma_{i+1})P_{t-i-1} - A\Gamma_{k-1}P_{t-k} + A\Psi Z_t + Ae_t. \tag{11}$$

Swanson and Granger (1997) suggest acyclic graphical methods applied to the covariance matrix of the VECM error terms can be used to obtain the contemporaneous causal ordering. Following Swanson and Granger (1997), Bessler and Akleman (1998) also suggest the use of acyclical graphical methods. However, Bessler and Akleman (1998) demonstrate the use of causal chains, forks, and colliders, whereas, Swanson and Granger (1997) only acknowledged use of causal chains. Several studies have extended the use of acyclical graphical methods (Bessler and Lee 2002, Demiralp and Hoover 2003, Hoover 2005, Moneta 2008, and Bryant, Bessler, and Haigh 2009).

A directed acyclic graph (DAG) is a way of summarizing the contemporaneous causal flow among the innovations from the VECM to provide the Bernanke ordering. Acyclical graphs assume there are no loops in causal chains such that no effect feeds back onto a direct or indirect cause, ruling out simultaneous equations. In a DAG, arrows are used to represent causal flows; X→Y indicates that variable X causes variable Y. A line connecting two variables, say W — X, indicates that W and X are connected by information flows, but the algorithm cannot determine if W causes X or vice versa. Two variables that are not connected by information flows are represented by the two variables having neither a line nor an arrow connecting them. Detailed development and discussion of DAGs can be found in Pearl (2000) and Spirtes, Glymour, and Scheines (2000). For further examples of applications of DAGs see Awokuse and Duke (2006), Mjelde and Bessler (2009), as well as Stockton, Bessler, and Wilson (2010). The GES algorithm developed by Chickering (2003) and implemented in TETRAD IV (2004) is used to obtain a DAG from the non orthogonal innovations covariance matrix.

CHAPTER IV

RESULTS

Time series properties of the data are discussed first. Next are results of further tests on the data after forming a VECM. Directed Acyclical Graphs are determined and the contemporaneous relationships of the 11 natural gas market prices are explained. Lastly, after re-expressing the VECM into a VAR allowing innovative accounting to be conducted, this chapter discusses the impulse response functions and forecast error variance decompositions.

Model Specification

Schwarz loss and Hannan and Quinn loss measurements are used to determine the "best" model in terms of the number of lags and exogenous variables. Because the 11 price series are highly volatile and potentially heteroscedastic, a logarithmic transformation of each price series is taken before performing any analysis. The number of lags and associated loss metrics are given in Table 4.1 for various model specifications for the exogenous variables.

Six different series of exogenous variables that may contribute information to the price dynamics of natural gas markets are considered (Table 4.1). Two of the six exogenous series use 0-1 qualitative (dummy) variables: seasonality and weekdays. Cooling and heating degree days for both the U.S. and Canada (CDD+HDD) are the

Table 4.1. Loss Metrics on the Order of Lags in a Levels Vector Autoregression. Tests are on Logarithm of Prices for 11 U.S. and Canada Natural Gas Markets and Four Seasonal and Five Weekday Dummy Variables, and Four Exogenous Cooling and Heating Degree Days Variables, Daily Data March 11, 1994-March 25, 2009.

Model	Lags	SL[d]	Lags	H&Q[d]
Model with No Price Lags				
Constant (no exogenous)	0	-48.3371	0	-48.3484
Seasonal[a]	0	-48.7708	0	-48.8160
Weekday[b]	0	-48.2489	0	-48.3054
CDD+HDD[c]	0	-48.6827	0	-48.7731
Seasonal, weekday	0	-48.9685	0	-49.0250
Seasonal, CDD+HDD	0	-48.9997*	0	-49.0901*
Weekday, CDD+HDD	0	-48.8806	0	-48.9823
Seasonal, weekday, CDD+HDD	0	-48.9118	0	-49.0474
Models with Price Lags				
Constant (no exogenous)	3	-68.3853*	4	-68.7785
Seasonal	3	-68.3528	4	-68.7774
Weekday	3	-68.3532	4	-68.7933
CDD+HDD	3	-68.3687	4 & 5	-68.8061
Seasonal, weekday	3	-68.3205	4	-68.7923
Seasonal, CDD+HDD	3	-68.3143	4	-68.7849
Weekday, CDD+HDD	3	-68.3362	4	-68.8207*
Seasonal, weekday, CDD+HDD	3	-68.2818	4	-68.7995

a) Four seasonal dummy variables representing each quarter of the year; winter, spring, summer, and fall.
b) Five dummy variables representing trading days of the week (Monday thru Friday).
c) CDD+HDD consists of four series; U.S. cooling degree day, U.S. heating degree day, Canadian cooling degree day, and Canadian heating degree day (see Data and Variable Specification for further explanation).
d) SL = Schwarz Information Criteria, H&Q = Hannan and Quinn criteria. SL and H&Q are calculated using residual sum of squares (RSS) as follows; SL=N(log(RSS)) + 2K, and H&Q = log(RSS) + (2.01)(k)log(logT)/T, where K = number of lags and T = number of observations. One to ten lags are used in each model to test for "best" model. Number of lags is associated with minimum SL and H&Q loss measures for each specification.

other four exogenous variables considered. All cooling and heating degree day variables are tested when CDD+HDD for the U.S. and Canada are shown in Table 4.1. The minimum Schwarz loss metric is -68.3853 which correspond to a model with a constant, three price lags, and no exogenous variables. Minimum Hannan and Quinn loss metric is -68.8207 which corresponds to a model including a constant, four price lags, weekday dummy variables, and CDD+HDD.

Geweke and Meese (1981) suggest that Schwarz loss metric may have tendencies to over penalize additional regressors compared to the other metrics. The model suggested by Hannan and Quinn with four lags picks up information from the previous four days of trading. Also including a weekday dummy suggest information is contained in each particular day of the week that trading takes place. Quite possibly traders buy more or less of natural gas on certain weekdays. Large gas trades, in theory, may occur on Friday in anticipation of use through the weekend and on Monday to resupply used stocks. Inclusion of CDD+HDD may also be capturing season affects. Further, a model including CDD+HDD variables agrees with observations and previous studies (Park, Mjelde, and Bessler 2008) that suggest natural gas use is affected by temperature values. If the winter temperature in Chicago, for example, decreases then there would be an increase in demand for heating which would lead to an increase in consumption of natural gas. Following these considerations, a four lags VAR model with a constant and the exogenous variables, weekday and CDD+HDD, are used as suggested by the Hannan and Quinn loss measure.

Table 4.2. Tests of Cointegration among Logarithms of Natural Gas Prices with Four Lags of Prices for 11 U.S. and Canada Markets, with Contemporaneous Cooling and Heating Degree Days, and Weekday Dummy Variables, Daily Data March 11, 1994-March 25, 2009.

R	T*	C (1%)*	D*	T	C (1%)	D
0	2485.726	304.886	R	2469.202	291.584	R
1	1924.469	258.309	R	1912.512	246.169	R
2	1438.196	216.079	R	1430.066	204.636	R
3	1065.429	177.415	R	1059.899	166.951	R
4	757.645	142.336	R	753.967	133.042	R
5	472.643	111.379	R	470.480	102.948	R
6	280.889	83.930	R	279.500	76.374	R
7	154.888	60.422	R	154.067	53.910	R
8	63.198	40.837	R	62.776	34.872	R
9	21.786	24.735	F	21.488	19.694	R
10	7.068	12.731	F	6.402	6.635	R

Number of cointegrating vectors R is tested using the trace test with the constant within and outside the cointegrating vectors. The test statistic (T) is the calculated trace test, associated with the number of cointegrating vectors given in the left-hand-most column. Approximate critical values (C (1%)) are taken from Table B.2 (constant within) and Table B.3 (constant outside) in Hansen and Juselius (1995, p. 80-81). The tests results presented in columns marked by an asterisk are associated with a constant within the cointegrating vectors. The unasterisked columns are associated with tests on no constant in the cointegrating vectors, but a constant outside the vectors. The column labeled "D" gives the decision to reject (R) or fail to reject (F), at a 1% level of significance the null hypothesis of the number of cointegrating vectors ($r = 0$, $r \leq 1, \ldots, r \leq 10$). Following Johansen (1992), the test stops at the first "F" (failure to reject) when starting at the top of the table and moving sequentially across from left to right and from top to bottom. Here, we fail to reject the null for all $r \leq 9$ concluding that there are nine cointegrating vectors with a constant within the cointegrating vectors.

The number of cointegrating vectors is determined by trace tests and loss metrics. Trace test results are given in Table 4.2. Johansen (1992) recommends testing for whether the constant is within or outside of the cointegration space (see the brief discussion of this test in the note to Table 4.2). Here, nine cointegrating vectors with a constant within the cointegrating space are found. For further examination of the

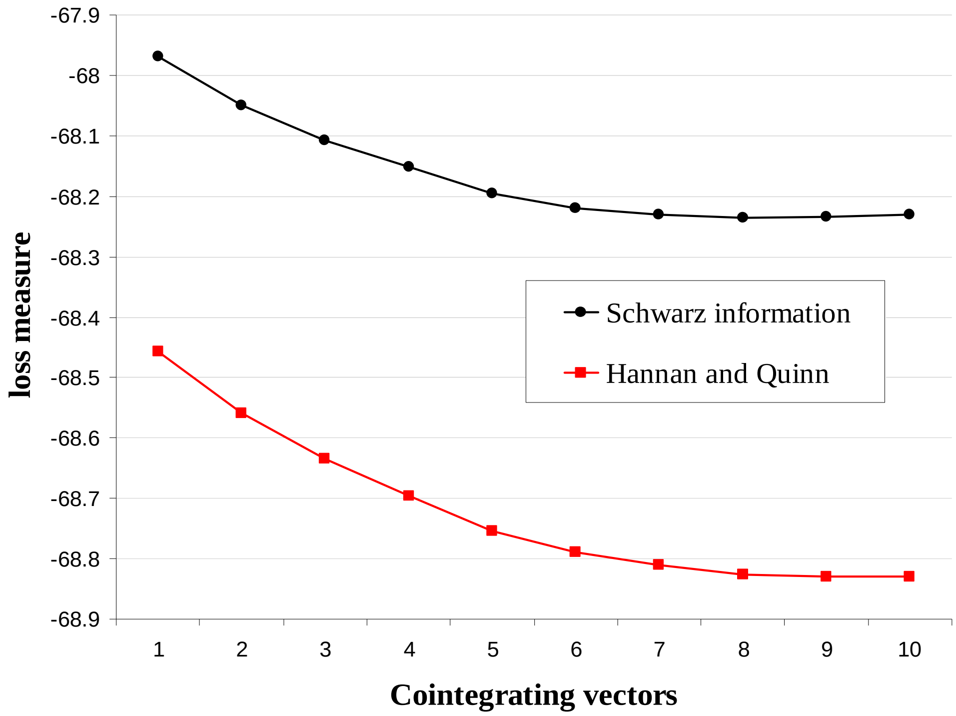


Figure 4.1. Schwarz information criteria and Hannan and Quinn loss functions on the number of cointegrating vectors on the VECM. The VECM is fit on logarithms of 11 natural gas markets with four lags of prices. Minimum SL (-68.236) occurs at eight cointegrating vectors and minimum H&Q (-68.830) occurs at nine and ten cointegrating vectors. SIC and Phi are calculated using residual sum of squares (RSS) as follows; SL = N(log(|Σ|) + 2K, and H&Q = log(|Σ|) + (2.01)(k)log(logT)/T, where K = number of parameters and T = number of observations.

number of cointegrating vectors Wang and Bessler (2005) suggest plotting Schwarz loss and Hannan and Quinn loss measures. Such plots for one through ten cointegrating vectors are shown in Figure 4.1. Schwarz loss is at a minimum with eight cointegrating vectors. Hannan and Quinn loss measure is minimized at nine and ten cointegrating vectors. After considering the trace tests results (nine cointegrating vectors) and loss metrics (eight, nine, and ten cointegrating vectors), nine cointegrating vectors with a constant in the cointegrating space is imposed on the model.

Stationarity, Exclusion, and Exogeneity

Given nine long-run relations (cointegrating vectors) it is of interest to know if one or more of these long-run relations arise because a series is stationary. One or more of the cointegrating vectors might arise, not from a linear combination of two or more individual price series, but because one or more of the series is itself stationary (returns to its historical mean with regularity). Augmented Dickey-Fuller (ADF) tests are shown in Table 4.3. Results in the upper portion of Table 4.3 indicate that New York price series is stationary in levels at a 1% significance level, critical value of -3.42 compared to a test value of -3.50 (Fuller 1976), the remaining ten price series are non-stationarity. The lower portion of Table 4.3 reports results from testing first differences. The tests indicate that all first difference price series are found to be stationary at a 1% significance level. Further tests for stationarity within the VECM (Table 4.4) suggest all 11 price series are non-stationary at the 1% significance level.

Exclusion tests reject the null hypotheses associated with each individual price series suggesting all price series are in the long-run relationships (Table 4.5). Weak exogeneity tests (Table 4.6) show that all null hypotheses are rejected (p-values for each series is less than 0.000). This suggests that each market is weakly exogenous with respect to perturbations in the co-integrating space; meaning, all prices respond to shocks (perturbations) in the long-run information embedded in the data.

Table 4.3. Tests for Non Stationarity of Logarithms of Prices and First Differences of Logarithms of Prices for U.S. and Canada Natural Gas Prices, Daily Data March 11, 1994-March 25, 2009

	Augmented Dickey-Fuller					
Series	t-test	D	SL[a]	Lags (k)	H&Q[a]	Lags (k)
			Levels			
Henry Hub	-2.33	F	-6.0850	2	-6.0892	2
Chicago	-2.38	F	-5.3872	7	-5.3996	10
New York	-3.50	R	-4.5247	6	-4.5330	6
Malin	-2.36	F	-5.6144	10	-5.6268	10
Iroquois	-2.58	F	-5.3523	5	-5.3595	5
Niagara	-3.17	F	-5.5382	3	-5.5433	3
Dawn	-2.81	F	-5.8473	4	-5.8535	4
Empress	-2.32	F	-5.6496	2	-5.6538	2
AECO	-2.36	F	-5.5432	2	-5.5474	2
Kingsgate	-2.60	F	-5.6792	2	-5.6833	2
Sumas	-3.03	F	-5.3660	3	-5.3723	6
			First Differences			
Henry Hub	-51.30	R	-6.0860	1	-6.0891	1
Chicago	-31.22	R	-5.3881	6	-5.3994	9
New York	-33.15	R	-4.5240	5	-4.5312	5
Malin	-20.87	R	-5.6158	10	-5.6281	10
Iroquois	-33.62	R	-5.3529	4	-5.3591	4
Niagara	-45.27	R	-5.5380	2	-5.5421	2
Dawn	-37.83	R	-5.8477	3	-5.8529	3
Empress	-54.94	R	-5.6506	1	-5.6537	1
AECO	-56.41	R	-5.5442	1	-5.5473	1
Kingsgate	-51.39	R	-5.6798	1	-5.6829	1
Sumas	-40.53	R	-5.3660	2	-5.3717	5

Ten lags are used to test for minimum values of loss metrics in the Augmented Dickey-fuller test. Augmented Dickey-Fuller test statistics are the t-statistics of estimated coefficient on the lagged level variable. This t-statistic is not distributed as a standard t-distribution under the null hypothesis. Critical values are given in Fuller (1976). The null hypothesis for Augmented Dickey-Fuller test is that the variables are non-stationary in levels and stationary in first differences. The 1%, 5%, and 10% significance level critical values are -3.42, -2.86, and -2.57. The column labeled "D" gives our decision to reject (R) or fail to reject (F) the null hypothesis. The null hypothesis is rejected when the observed t-statistics are less than this critical value.

a) SL = Schwarz Information Criteria, H&Q = Hannan and Quinn criteria. SL and H&Q are calculated using residual sum of squares (RSS) as follows; SIC = N(log(RSS)) + 2K, and Phi = log(RSS) + (2.01)(k)log(logT)/T, where K = number of lags and T = number of observations. Lags corresponding to the minimum SIC and Phi value of each criterion are presented.

Table 4.4. Tests of Stationarity of Each Natural Gas Market in the Cointegration Space. Tests are on the VECM of 11 Natural Gas Spot Market Prices with Cooling and Heating Degree Days and a Weekday Dummy Variable, Daily Data March 11, 1994-March 25, 2009.

Series	Chi-Squared Test	*p*-value	D
Henry Hub	23.373	0.000	R
Chicago	32.104	0.000	R
New York	32.999	0.000	R
Malin	47.740	0.000	R
Iroquois	25.435	0.000	R
Niagara	71.794	0.000	R
Dawn	72.870	0.000	R
Empress	26.724	0.000	R
AECO	34.067	0.000	R
Kingsgate	33.697	0.000	R
Sumas	38.608	0.000	R

Tests are on the null hypothesis that the logarithm of the particular series listed in the far left-hand column is stationary in its levels. The heading labeled D relates to the decision to reject (R) or fail to reject (F) the null hypothesis at a 1% level of significance (p-value of 0.01). Under the null hypothesis, the test statistic distributed chi-squared with six degrees of freedom.

Table 4.5. Tests of Exclusion of Each Natural Gas Market and Exogenous Variables from the Cointegration Space. Tests are on the VECM of 11 Natural Gas Spot Market Prices, Daily Data March 11, 1994-March 25, 2009.

Series	Chi-Squared Test	*p*-value	Decision
Henry Hub	391.112	0.000	R
Chicago	404.613	0.000	R
New York	357.588	0.000	R
Malin	178.960	0.000	R
Iroquois	291.354	0.000	R
Niagara	528.346	0.000	R
Dawn	516.010	0.000	R
Empress	145.122	0.000	R
AECO	122.717	0.000	R
Kingsgate	297.670	0.000	R
Sumas	250.584	0.000	R
Constant	42.654	0.000	R

Tests are on the null hypothesis that the particular series listed in the far left-hand column is not in the cointegration space. The heading labeled D relates to the decision to reject (R) or fail to reject (F) the null hypothesis at a 1% level of significance. Under the null hypothesis, the test statistic is distributed chi-squared with ten degrees of freedom.

Table 4.6. Tests of Weak Exogeneity of Each Natural Gas Market from the Cointegration Space. Tests are on the VECM of 11 Natural Gas Spot Market Prices, Daily Data March 11, 1994-March 25, 2009.

Series	Chi-Squared Test	*p*-value	Decision
Henry Hub	38.282	0.000	R
Chicago	261.733	0.000	R
New York	315.856	0.000	R
Malin	80.307	0.000	R
Iroquois	211.593	0.000	R
Niagara	162.290	0.000	R
Dawn	112.707	0.000	R
Empress	56.062	0.000	R
AECO	54.838	0.000	R
Kingsgate	110.051	0.000	R
Sumas	85.184	0.000	R

The null hypothesis is that each market is weakly exogenous, that is the series does not respond to perturbations in the cointegrating space. The Decision heading relates to the decision to reject (R) or fail to reject (F) the null hypothesis at a 1% level of significance. Under the null hypothesis, the test statistic is asymptotically distributed chi-squared with ten degrees of freedom. Cooling and Heating Degree Days and Weekday Dummy Variables are assumed exogenous.

Contemporaneous Structure

Based on the contemporaneous innovation correlation matrix, which is constructed from the correlation matrix from the residuals associated with the estimated VECM (Table 4.7), the contemporaneous causal flows suggested by GES algorithm with a penalty discount (Ramsey et al. 2009) equal to one are given in Figure 4.2. Sumas is an information sink in contemporaneous time; receiving information but not passing any information to other markets. AECO receives information from Kingsgate, Henry Hub, and Empress. Information passes from AECO to Sumas. Chicago receives information from Dawn, Henry Hub, and Iroquois while passing on information to Empress, Malin, and Sumas. Empress receives information from five markets (Chicago, Dawn, Henry

Table 4.7. Correlation Matrix of the Residuals from the VECM of Logarithms of Prices of 11 Natural Gas Markets in the U.S. and Canada, Cooling and Heating Degree Days, and Weekday Dummy Variables Assuming Nine Cointegrating Vectors, Daily Data March 11, 1994-March 25, 2009.

	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
HH	1.0000										
CH	0.6975	1.0000									
NY	0.4628	0.3928	1.0000								
MALI	0.5027	0.3987	0.2686	1.0000							
IROQ	0.5856	0.5173	0.6585	0.3633	1.0000						
NIAG	0.6185	0.5730	0.5704	0.3540	0.6907	1.0000					
DAWN	0.6367	0.6182	0.4502	0.4079	0.5394	0.7604	1.0000				
EMPR	0.4282	0.3240	0.2356	0.4043	0.3247	0.4036	0.4680	1.0000			
AECO	0.4213	0.3233	0.2381	0.3943	0.3186	0.3916	0.4572	0.9316	1.0000		
KING	0.4504	0.3744	0.2390	0.5982	0.3503	0.4090	0.4444	0.5173	0.5037	1.0000	
SUMA	0.4067	0.3511	0.2138	0.5720	0.3050	0.3266	0.3644	0.4236	0.4166	0.6539	1.0000

Hub, Kingsgate, and Malin), while sending information to AECO. Henry Hub receives information from Dawn, Iroquois, Niagara, and New York. Information flows from Henry Hub to AECO, Chicago, Empress, Kingsgate, and Malin. Dawn, Henry Hub, Malin, Niagara, and New York all provide information to Kingsgate while AECO, Empress, and Sumas receive information from Kingsgate. Malin receives information from Chicago, Dawn, Henry Hub, Iroquois, and Niagara while providing information to Empress, Kingsgate, and Sumas. For the remaining markets; Dawn, Iroquois, Niagara, and New York, the GES algorithm does not suggest the directions of at least one edge between the four markets.

Four undirected edges from the GES algorithm (Figure 4.2) are Dawn to Niagara, Niagara to Iroquois, New York to Niagara, and New York to Iroquois. Increasing the

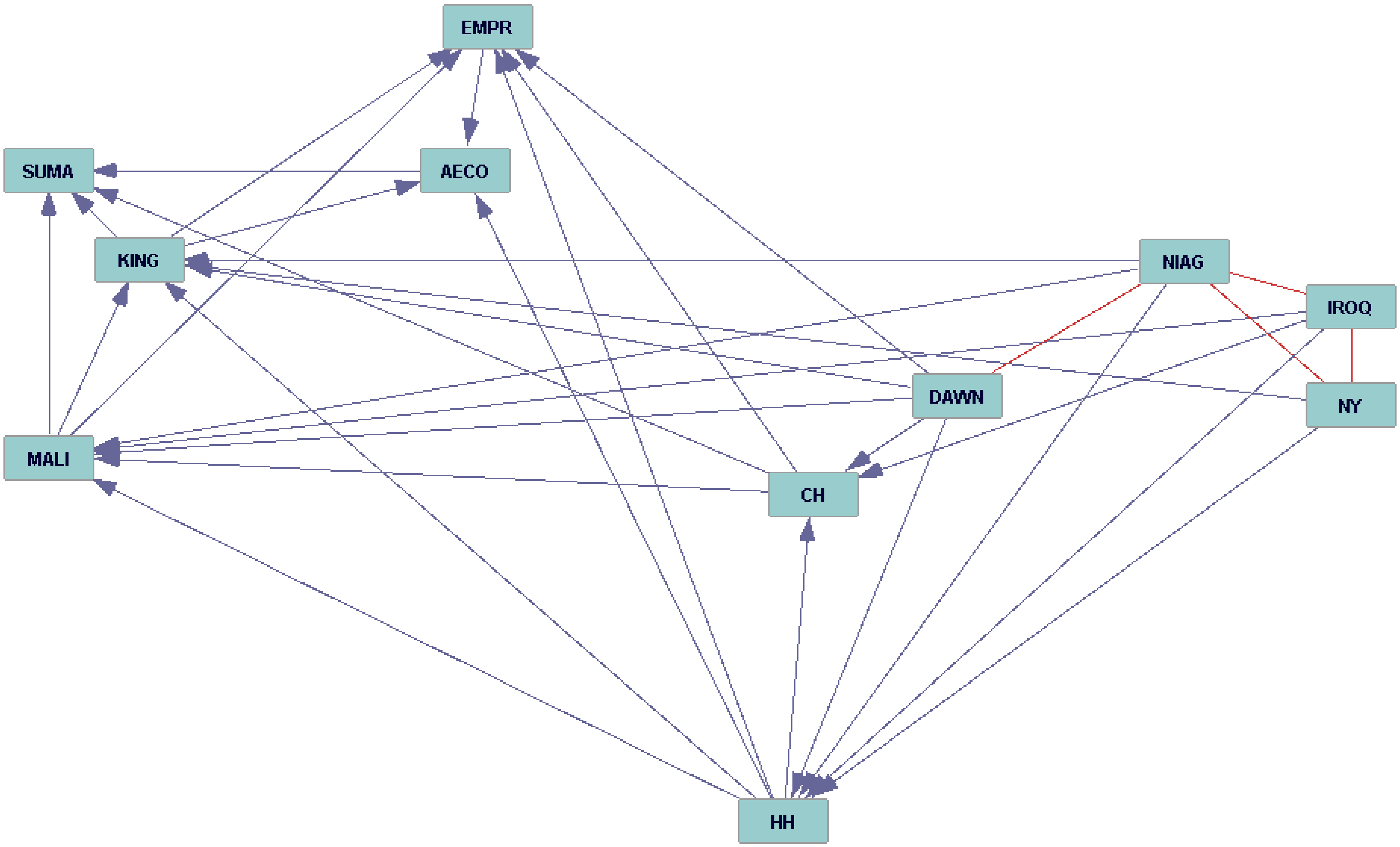
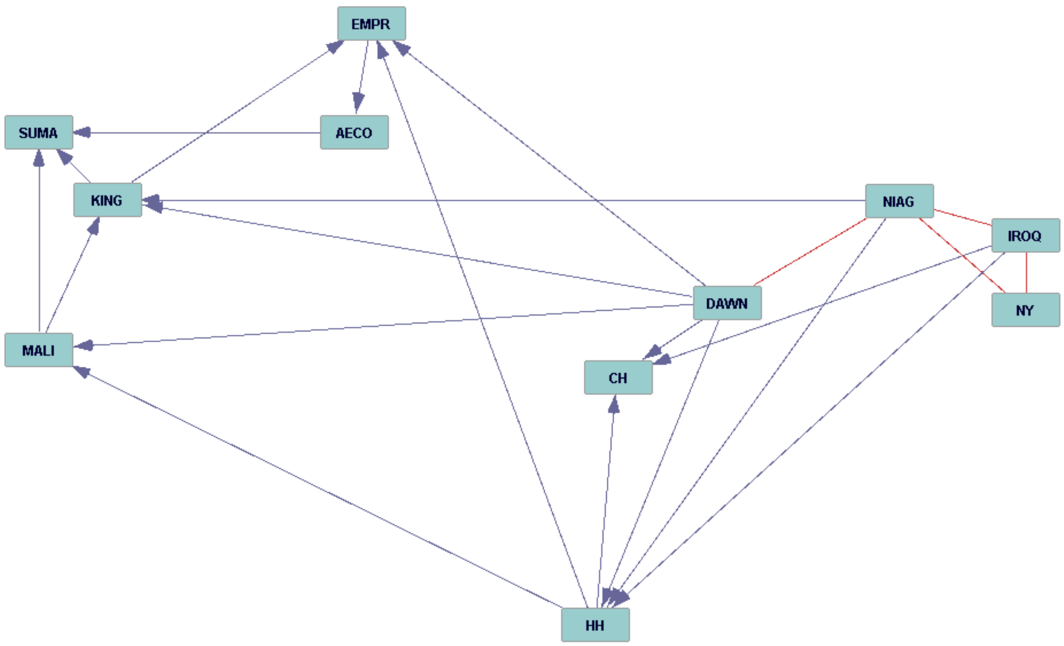


Figure 4.2. Contemporaneous causal relations among 11 U.S. and Canada natural gas markets using GES algorithm with a penalty discount of one. There are 29 directed edges and four undirected edges. The four undirected edges are highlighted in red.

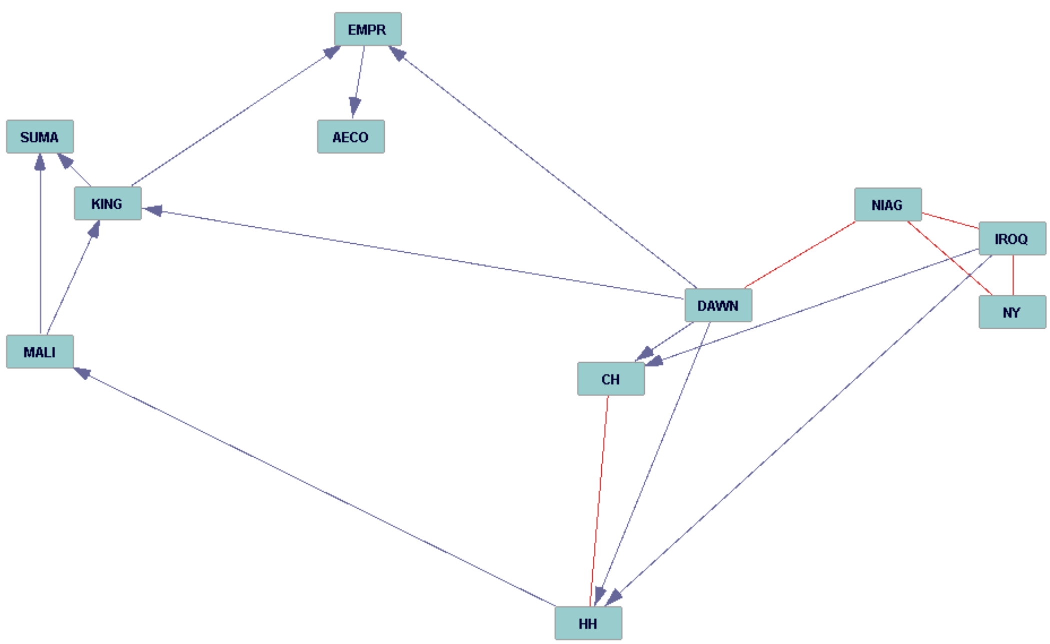
penalty function[1] in the BIC score may mitigate the undirected edge problem helping to determine the structure (Ramsey et al. 2009). Contemporaneous causal structure suggested using a penalty discount equal to three and six are shown in Figure 4.3. Applying penalty discounts of one and three produce the same four undirected edges in the contemporaneous structure, while a penalty discount of six produces five undirected edges. Increasing the penalty discount in this case, therefore, does not help determine the direction of the four original undirected edges. As such, the contemporaneous structure given by the GES algorithm with a penalty discount of one is used in this analysis. After eliminating cyclical patterns, eight potential DAGs of contemporaneous causality remain (see Appendix A Figures A.1 through A.8). There are two causal chains, Dawn to Iroquois chain (Figure A.1) and Dawn to New York chain (Figure A.2), and three causal forks, Iroquois fork (Figure A.3 and A.4), Niagara fork (Figure A.5 and A.6), and New York fork (Figure A.7 and A.8). For each fork, there is one directed edge that can be directed in either of two directions resulting in eight potential contemporaneous causal relations.

The Niagara, Iroquois, and New York fork structures make Niagara, Iroquois, and New York exogenous in contemporaneous time; meaning no markets cause price movements in these particular markets. In Dawn to Iroquois and Dawn to New York chains, Dawn is exogenous. Chi-squared and BIC tests performed on the eight DAGs, to determine the best contemporaneous causal ordering structure, have equal values across

[1] See Ramsey et al. (2009) for further explanation of the penalty discount. The GES procedure to determine directed edges is partially controlled by the penalty term cln(n) of the BIC score. The penalty can be multiplied by any constant c greater than 1. The BIC score is -2ln(ML)+cln(n) (Schwarz 1978) where ML is the maximum likelihood estimate, n is the sample size, and c is the penalty discount.



Penalty discount = 3



Penalty discount = 6

Figure 4.3. Contemporaneous causal relations among 11 U.S. and Canada natural gas markets using GES algorithm with a penalty discount of three and six. Eighteen directed edges and four undirected edges make up the directed graph with a discount of three, and 12 directed edges and five undirected edges make up the directed graph with a discount of six. Undirected edges are marked in red.

all eight models (chi-squared of 29.05 and BIC of -152.99). Other information is necessary to provide a contemporaneous structure for innovation accounting procedures.

Using information that Dawn market has the largest gas throughput, of the four markets with undirected edges, (U.S. DOE 2009c) it is assumed that Dawn is exogenous. Also, next to Dawn market is Canada's largest and one of North America's largest underground storage facility owned by Union Gas (Union Gas 2010). The two Dawn chains, therefore, are considered for further analysis to determine the causal structure, while the three forks are not considered. Impulse response functions (IRFs) for the Dawn to Iroquois chain (Figure B.1) are better behaved than Dawn to New York chain's IRFs (Figure B.2) (see Appendix B for IRFs of all eight DAGs). For example, in Figure B.2 Henry Hub's normalized responses (first row of matrix) to a shock in other markets shows that Henry Hub responds to Chicago, Iroquois, Niagara, and Dawn, as well as, its own market near perfectly, whereas Henry Hub's responses to the other six markets are near zero. This odd behavior is not as prevalent using the Dawn to Iroquois chain (Figure B.1). Note, however, that responses of Henry Hub in Figure B.2 (first row of matrix) compared with the responses in Figure B.1 (first row of matrix) are the same in direction (positive or negative). Further differences are Malin's responses to shocks in Henry Hub, Chicago, New York, Iroquois, Niagara, and Dawn between the two causal structures of Figure B1. and Figure B.2. Dawn to Iroquois chain (Figure 4.4 same as B.1), therefore, is used as the contemporaneous causal ordering structure for reporting innovation accounting procedures.

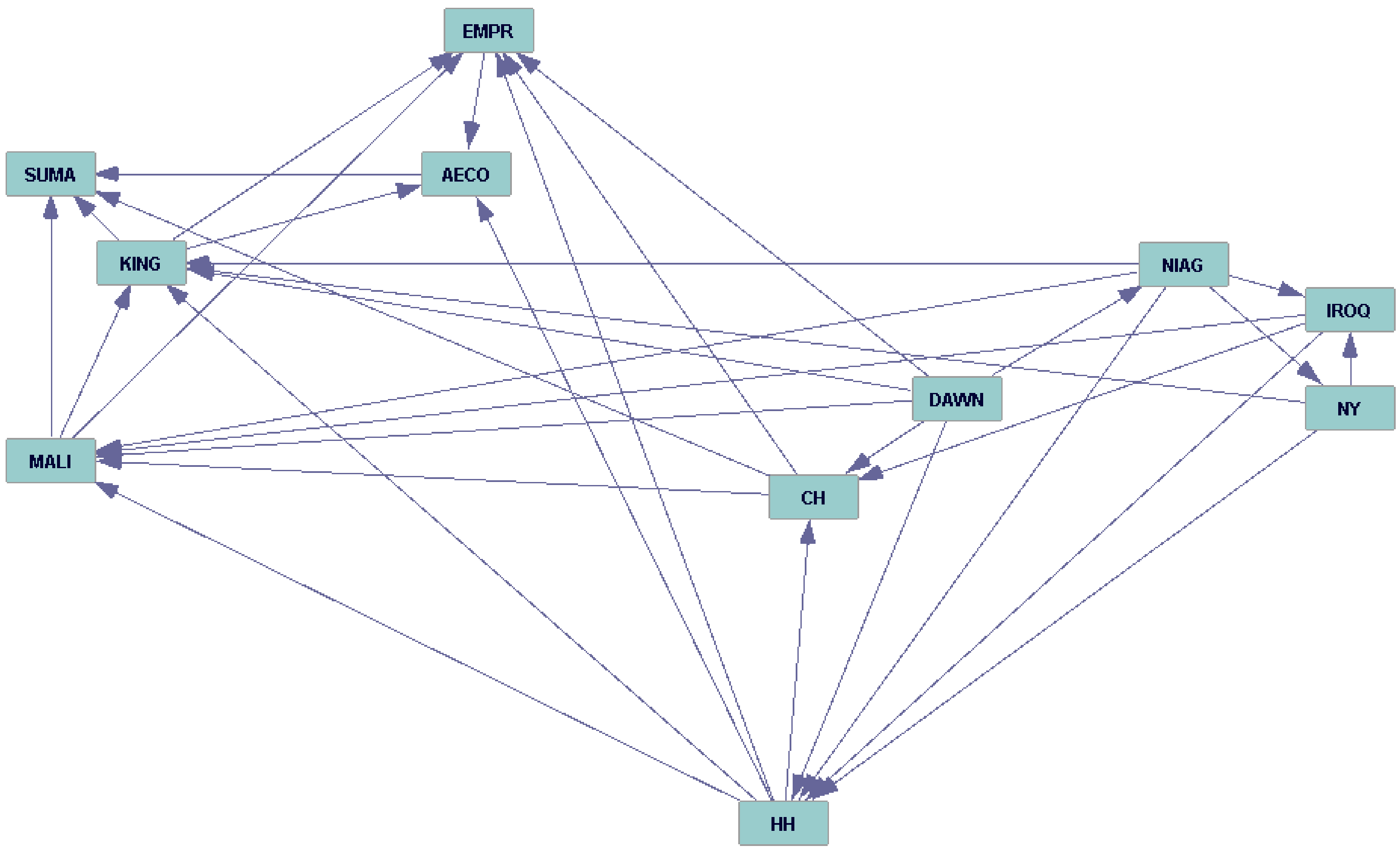


Figure 4.4. Directed Acyclical Graph for 11 U.S. and Canada natural gas markets using GES algorithm with a penalty discount of one. Thirty-three directed edges make up the directed graph, assuming Dawn to Iroquois chain.

Table 4.8. Correlation Matrix of Logarithms of 11 U.S. and Canada Natural Gas Market Price Series, Daily Data March 11, 1994–March 25, 2009.

	HH	CH	NY	MALIN	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
HH	1.0000										
CH	0.9915	1.0000									
NY	0.9598	0.9568	1.0000								
MAL	0.9475	0.9382	0.9014	1.0000							
IROQ	0.9882	0.9855	0.9751	0.9284	1.0000						
NIAG	0.8941	0.8958	0.8800	0.8748	0.9017	1.0000					
DAWN	0.8962	0.8986	0.8673	0.8812	0.8959	0.9935	1.0000				
EMPR	0.8572	0.8441	0.8123	0.9217	0.8404	0.9165	0.9215	1.0000			
AECO	0.8551	0.8419	0.8096	0.9207	0.8377	0.9105	0.9158	0.9984	1.0000		
KING	0.8483	0.8383	0.8069	0.9356	0.8311	0.9114	0.9171	0.9842	0.9822	1.0000	
SUMA	0.8400	0.8311	0.8043	0.9340	0.8240	0.8970	0.9020	0.9732	0.9712	0.9909	1.0000

Unconditional correlations of the 11 natural gas prices series show that there is a high degree of correlation among the markets. In Table 4.8, correlations are greater than 0.99 for four market pairs. These market pairs are Henry Hub and Chicago, Niagara and Dawn, Empress and AECO, and Kingsgate and Sumas. In each case, markets with correlations greater than 0.99, are located geographically close to each other. No market pair has a correlation value less than 0.80. The lowest correlation (0.8043) is for New York and Sumas markets located on opposite ends of the continent.

Impulse Response Functions

Impulse response functions of the Dawn to Iroquois chain are presented as a matrix of graphs as normalized dynamic responses of each series to a one-time-only shock in each series (Figure 4.5). Each sub-graph provides the response of the market given by the row heading to a one-time-only shock in the series listed in the column heading. The purpose of these graphs is not to give precise metrics, but rather to provide a qualitative

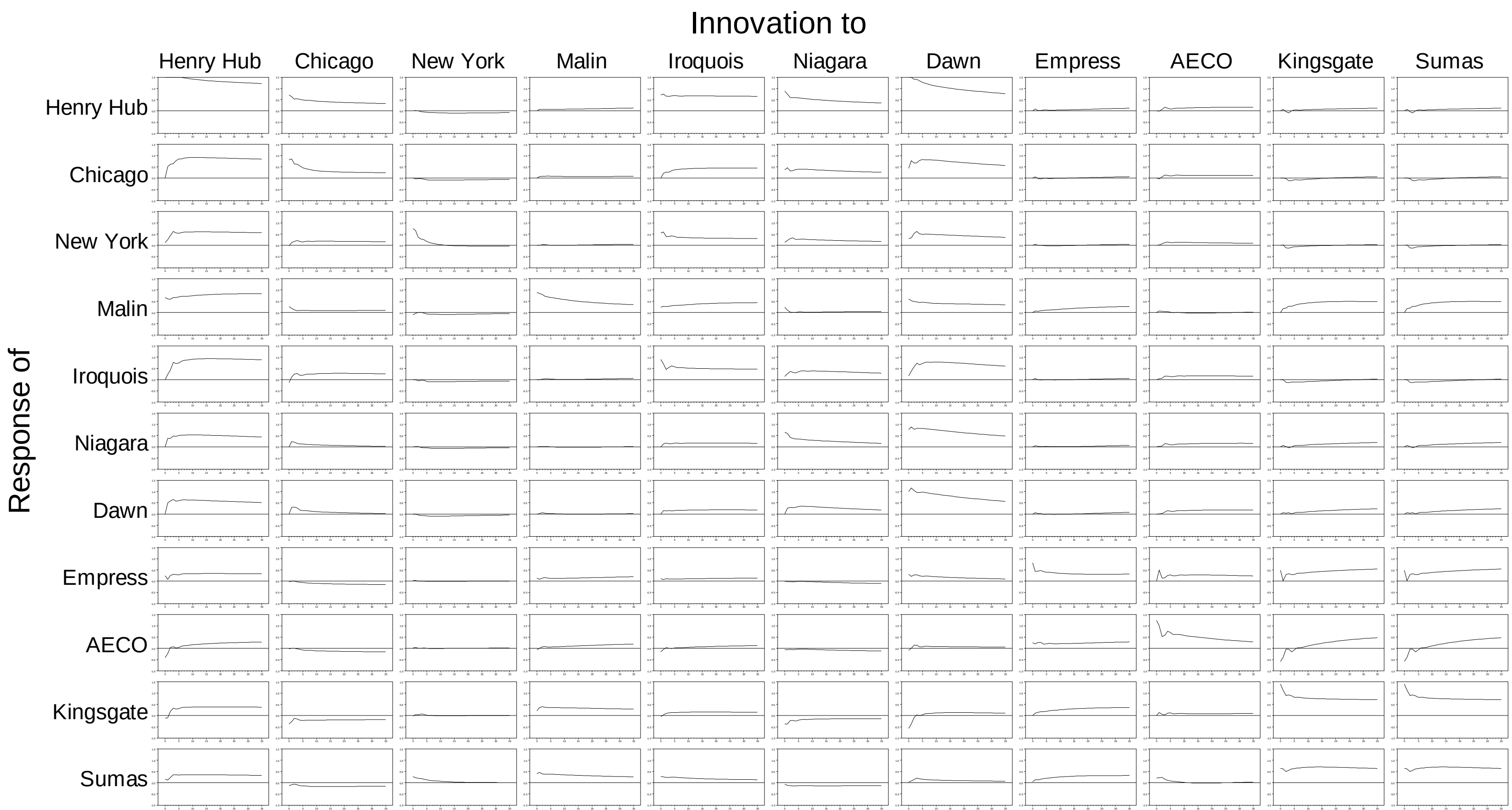


Figure 4.5. Impulse response functions of 11 U.S. and Canada natural gas market prices. Responses to a single innovation (shock) in each series assuming Dawn to Iroquois chain as the contemporaneous causal structure.

sense of how (relative magnitude and direction) each series reacts to a one time shock in each of the 11 series. The responses are normalized; each response is divided by the standard error of the innovations for that series, allowing the series' responses to be compared.

Response of Henry Hub to its own shock is initially strongly positive and over time tappers off slightly, yet having a permanent positive effect on its own natural gas price (Figure 4.5). Similarly, all other markets show strong positive responses initially from a shock in their own price (diagonal elements in Figure 4.5). Generally, these responses tapper off as other markets adjust, but remain positive. Responses of the U.S. markets, Chicago, New York, Malin, and Iroquois and the Canadian markets, Niagara and Dawn, to a shock in Henry Hub (far left column) are positive and persist over time. What happens in Henry Hub affects the U.S. and eastern Canada markets. Western Canada markets, Empress, AECO, Kingsgate, and Sumas are minimally impacted by a shock at Henry Hub.

Dawn positively impacts Henry Hub, Chicago, New York, Iroquois, and Niagara, but has a negative impact on Malin, Empress, AECO, Kingsgate, and Sumas. The Canadian markets AECO, Kingsgate, and Sumas which are located geographically near Empress, react positively to a shock in Empress. The two northwest Canadian markets Kingsgate and Sumas, impact all other markets in a similar manner (see the two far right columns). Kingsgate and Sumas, when shocked have an initial positive impact on all markets except Chicago, New York, Iroquois, and AECO. The effects on the U.S.

markets, except Malin, in the long-run are positive yet small, and effects on the Canadian markets are all positive.

Results show that natural gas markets located in the same region tend to have similar impulse response functions, whereas, markets in different regions tend to react differently. To illustrate, Kingsgate and Sumas, respond nearly identical to shocks in the 11 markets as illustrated by the bottom two rows in Figure 4.5. Other examples include the row matrices of New York and Iroquois, Niagara and Dawn, as well as Chicago and Henry Hub. These similarities indicate markets close in proximity react in likeness to shocks in natural gas prices. Markets separated by regions, such as Sumas and New York, Niagara and Kingsgate, even Malin and Henry Hub behave somewhat differently. A price increase at Dawn, for example, seems to positively affect the price at Henry Hub, while negatively affecting the price at Malin. Likewise, a price increase at Chicago seems to have relatively little effect on New York, while Sumas' price decreases.

Forecast Error Variance Decompositions

A more precise measure of the dynamic interactions among the 11 natural gas spot markets is given by the forecast error variance decompositions (Table 4.9). Decompositions give the percentage of price variation in each market at time $t + k$ (the horizon) that is due to innovations in each market, including itself, at time t (contemporaneous time). Decompositions at horizons of zero (contemporaneous time), one, and 30 trading days ahead are provided. Each sub-panel (e.g. Henry Hub, LA) of the table is split into three rows (0, 1, or 30 days) indicating the horizon. Each row gives

Table 4.9. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets, Assuming Dawn to Iroquois Chain.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
Henry Hub, Louisiana (HH)											
0	44.04	6.50	0.00	0.00	6.34	10.00	33.12	0.00	0.00	0.00	0.00
1	43.63	6.12	0.00	0.04	7.16	9.06	33.89	0.05	0.00	0.04	0.02
30	48.20	4.64	0.16	0.20	10.86	6.28	28.86	0.11	0.48	0.15	0.07
Chicago Citygate, Illinois (CH)											
0	0.00	67.16	0.00	0.00	0.00	13.85	18.99	0.00	0.00	0.00	0.00
1	9.22	48.94	0.04	0.20	1.63	12.29	27.54	0.11	0.04	0.00	0.01
30	42.36	9.24	0.33	0.33	9.79	6.97	29.92	0.04	0.81	0.14	0.05
Transco Z6 NY, New York (NY)											
0	1.56	0.09	55.95	0.00	30.98	1.97	9.45	0.00	0.00	0.00	0.00
1	4.00	0.72	49.14	0.00	32.72	3.17	10.03	0.09	0.01	0.02	0.11
30	40.53	3.73	5.41	0.06	16.07	6.75	25.41	0.05	1.58	0.24	0.17
Malin, Oregon (MALI)											
0	24.75	3.73	0.64	44.20	3.06	2.97	20.64	0.00	0.00	0.00	0.00
1	24.07	2.98	0.38	45.32	3.93	1.86	19.17	0.15	0.10	0.85	1.19
30	40.09	0.68	0.35	20.97	9.47	0.19	11.49	2.25	0.04	12.46	2.02
Iroquois, New York (IROQ)											
0	0.00	2.16	0.00	0.00	92.34	2.32	3.18	0.00	0.00	0.00	0.00
1	3.16	1.95	0.00	0.00	78.97	5.50	10.16	0.12	0.11	0.00	0.02
30	42.41	3.85	0.34	0.04	16.06	6.98	28.65	0.02	1.39	0.25	0.03
Niagara, Ontario (NIAG)											
0	0.00	0.00	0.00	0.00	0.00	42.17	57.83	0.00	0.00	0.00	0.00
1	6.13	2.28	0.01	0.01	0.68	32.89	57.63	0.12	0.01	0.14	0.10
30	26.79	0.96	0.34	0.02	2.87	10.49	54.26	0.08	2.10	1.63	0.46
Dawn, Ontario (DAWN)											
0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0
1	8.9	3.3	0.0	0.0	0.8	2.3	84.3	0.2	0.0	0.2	0.1
30	27.6	1.3	0.5	0.0	2.5	6.4	57.4	0.1	2.1	1.7	0.5
Empress Spot, Alberta (EMPR)											
0	5.18	0.08	0.07	1.77	1.25	0.00	8.60	61.32	0.00	21.73	0.00
1	4.03	0.06	0.12	1.61	1.16	0.03	8.81	54.07	15.16	14.84	0.11
30	17.41	2.08	0.02	3.74	2.23	0.52	5.78	23.15	11.88	30.48	2.73
AECO C Spot, Alberta (AECO)											
0	7.91	0.02	0.02	0.21	1.00	0.17	0.31	2.77	71.69	15.92	0.00
1	6.43	0.01	0.06	0.13	0.71	0.21	0.19	2.94	74.57	14.67	0.08
30	7.91	2.38	0.02	2.46	1.12	0.96	1.09	9.68	56.50	14.88	2.99
Kingsgate, British Columbia (KING)											
0	0.46	5.48	0.02	1.64	0.08	5.52	12.26	0.00	0.00	74.54	0.00
1	0.50	4.94	0.06	3.84	0.06	6.36	10.44	0.26	0.39	72.45	0.70
30	11.04	3.63	0.03	9.35	1.80	2.92	2.35	6.89	0.63	56.11	5.26
Sumas, Washington (SUMA)											
0	1.56	0.98	4.81	10.39	4.68	0.30	0.07	0.11	2.83	25.17	49.11
1	1.32	0.82	4.17	12.47	4.65	0.61	0.23	0.62	3.19	25.37	46.55
30	11.19	2.41	0.93	11.20	3.71	1.77	1.20	7.19	0.67	43.68	16.04

the percentage of uncertainty (price variation) in natural gas price, at the given horizon, attributable to variations (innovations) in each market labeled as column headings. Each market's price variation, at the given horizon, is accounted for by previous information arising from (discovered in) its own past and that of the other ten markets shown as column headings. Individual rows sum to one allowing for rounding error.

In contemporaneous time, the uncertainty in Henry Hub natural gas price is primarily due to variation in innovations of its own price (44.04%) and Dawn (33.12%). While variation in innovations of Niagara (10.00%), Chicago (6.50%), and Iroquois (6.34%) prices play a minor role. The variation in Henry Hub at the 30 day ahead explained by innovations in own price, Henry Hub (48.20%). Iroquois' impact increases slightly (10.86%), while the variation in Henry Hub prices from innovations of other markets is more wide spread, Dawn (28.86%), Niagara (6.28%), Chicago (4.64%), with the remaining markets explaining very small amounts (0.48% to 0.07%). Other values in Table 4.9 have similar interpretations.

Each market's own price explains a large portion of the variation in price in contemporaneous time (diagonal matrix with horizon of 0), ranging from 100% in Dawn to 42.17% at Niagara with the next lowest 44.04% in Henry Hub. Dawn's forecast is the only market to explain a large portion of price variation in most of the other ten markets in contemporaneous time. Sumas explains none of the variation in price of any other market in contemporaneous time (see column labeled Sumas). The Dawn and Sumas findings are expected given that Sumas is an information sink and Dawn is exogenous (Figure 4.4).

Examining the four markets in the northwest, Empress, AECO, Kingsgate, and Sumas (lower right four columns and four rows in Table 4.9), Kingsgate is accountable for the variation of price at contemporaneous time in the other three markets, Empress (21.73%), AECO (15.92%), and Sumas (25.17%), while none of the other three markets is accountable for any variation of price in any of the other northwest markets, except for AECO which is accountable for 2.83% of price variation in Sumas and Empress accountable for 2.77% of price variation at AECO. Kingsgate, therefore, appears to be the most important market for price discovery among the northwest markets. Further examining by region, New York and Niagara are located next to one another, each within the state of New York. The percentage of price variation in Iroquois due to innovations at New York is zero, whereas the percentage of price variation in New York due to innovations at Iroquois is 30.98%. This infers that of the two markets located in the state of New York, Iroquois market is more important than New York in price discovery. In both scenarios, the northwest and New York state markets, the percent of the price variation reflects the contemporaneous structure shown in Figure 4.4. Kingsgate gives information to Empress, AECO, and Sumas, and New York receives information from Iroquois.

Moving to the day-ahead horizon, each market's price explained by variations to its own market decreases, except for Malin and AECO which each increase slightly.

Generally, the percentage of price variation due to other markets grows implying that more markets become important in explaining price variations as the horizon lengthens. Not all markets, however, contribute more to the variation of price as the horizon lengthens. For example, Chicago explains less of the price variation in Malin, Henry Hub, Kingsgate, and its own market as horizon goes from zero (contemporaneous time) to 30 days.

At the 30-day horizon, the spreading out of the percentage variation in price attributed to each market becomes more noticeable. Each market's percentage variation in price because of innovations in its own market falls noticeably (except for Henry Hub which rises); other markets explain a larger percentage share of price variation. In fact, there is only one market that does not explain at least a small percentage variation in price of another market (Malin explains Dawn 0.00%). Sumas, which didn't contribute to the percentage variation of price to any market except its own in contemporaneous time, contributes 5.26% to Kingsgate and at least 2.02% to the percentage variation in price of three other markets. The percentage variation in price attributed to other markets at a 30 day horizon ranges from 54.26% (Dawn explains Niagara) to 0.02% not including Malin explaining Dawn.

Two markets that play a main role in the source of price variation across markets in the long run are Henry Hub and Dawn. Interesting the percentage of price variation in Henry Hub depends primarily on what happens in its own market at both contemporaneous time and as the horizon increases. No other market exemplifies such tendencies. At a 30 day horizon, Henry Hub contributes largely to the U.S. markets Malin, Chicago, New York, Iroquois, and the eastern Canadian markets, Dawn and Niagara. Henry Hub contributes between 7.91% and 17.41% to the four western Canadian markets. At the 30 day horizon, Dawn contributes the most to another market, Niagara 54.26%. However, Dawn's influence in the long run does not affect other markets as highly as Henry Hub. The percentage of price variation from Dawn in all the U.S. markets and the eastern Canadian markets ranges from 54.26% to 11.49%, and hardly influences the price variation in any of the western Canadian markets (5.78% to 1.09%). Through the forecast error variance decompositions a better picture of the price discovery process arises; Henry Hub and Dawn are important players in this process.

Exogenous Variable Effects

Two sets of exogenous variables present in the model are weekday dummies and heating and cooling degree days. With four weekday coefficients (Friday is dropped to avoid perfect collinearity), there are 44 weekday coefficients in the 11 equations. Similarly with U.S. and Canada heating and cooling degree days, there are 44 coefficients in the equations. Thirty of the 44 weekday coefficients are significant at the 0.01% level (Table 4.10). Ten of the 14 coefficients that are not significant are associated with Thursday, while the remaining four are associated with Tuesday. All coefficients for Monday and Wednesday are significant.

For all markets, the following relationships hold for the coefficients. Monday's coefficient is always greater than Tuesday, Wednesday's coefficient is always greater

Table 4.10. Coefficient Values for Heating and Cooling Degree Days and Weekdays Associated with 11 Natural Gas Price Series, Daily Data March 11, 1994–March 25, 2009.

	Coefficients											
Series	coef	t-test	D	coef	t-test	D	coef	t-test	D	coef	t-test	D
	Day of the week											
	Mon			Tue			Wed			Thu		
HH	0.016	7.34	R	0.008	3.37	R	0.012	5.45	R	0.005	2.14	F
CH	0.019	6.22	R	0.007	2.30	F	0.018	5.84	R	0.005	1.70	F
NY	0.026	5.47	R	0.012	2.56	F	0.021	4.55	R	0.000	0.01	F
MALI	0.035	12.83	R	0.017	6.16	R	0.019	7.00	R	0.012	4.31	R
IROQ	0.018	6.02	R	0.010	3.13	R	0.019	6.04	R	0.001	0.20	F
NIAG	0.018	6.44	R	0.009	3.27	R	0.012	4.25	R	0.006	2.30	F
DAWN	0.012	5.13	R	0.006	2.66	R	0.008	3.40	R	0.003	1.10	F
EMPR	0.014	5.21	R	0.009	3.08	R	0.014	5.17	R	0.005	1.74	F
AECO	0.016	5.59	R	0.011	3.56	R	0.017	5.65	R	0.005	1.81	F
KING	0.019	7.29	R	0.006	2.14	F	0.013	4.77	R	0.004	1.62	F
SUMA	0.021	6.55	R	0.008	2.36	F	0.013	4.14	R	0.004	1.34	F
	Heating and cooling degree day											
	CHDD			CCDD			UHDD			UCDD		
HH	0.0000	-0.24	F	0.0001	0.23	F	0.0002	0.75	F	0.0002	0.64	F
CH	0.0012	5.77	R	0.0002	0.54	F	-0.0012	-3.16	R	0.0010	2.21	F
NY	0.0018	5.83	R	0.0009	1.47	F	0.0005	0.79	F	0.0040	5.78	R
MALI	-0.0001	-0.66	F	0.0000	-0.05	F	0.0003	0.88	F	-0.0001	-0.18	F
IROQ	0.0014	6.84	R	0.0003	0.74	F	-0.0007	-1.75	F	0.0013	3.00	R
NIAG	0.0008	4.52	R	0.0001	0.39	F	-0.0002	-0.57	F	0.0016	3.82	R
DAWN	0.0005	3.38	R	0.0001	0.31	F	-0.0004	-1.40	F	0.0006	1.56	F
EMPR	0.0004	2.34	F	0.0000	-0.11	F	-0.0007	-2.09	F	-0.0003	-0.76	F
AECO	0.0006	3.07	R	0.0000	0.06	F	-0.0011	-3.02	R	-0.0002	-0.45	F
KING	0.0001	0.30	F	0.0001	0.18	F	0.0000	0.06	F	-0.0002	-0.40	F
SUMA	0.0005	2.67	R	0.0002	0.60	F	-0.0008	-2.11	F	-0.0006	-1.21	F

Critical value for the associated t-test is 2.57. The letter D stands for the decision to reject or fail to reject the null hypothesis that the coefficient is statistically significant at a 0.01% significant level. Coefficient values estimate the change in logarithm of price.

than Tuesday, Tuesday's coefficient is always greater than Thursday, and Thursday's coefficient is always greater than Friday (recall, Friday was dropped, therefore its coefficient equals zero). Monday's coefficient is greater than the coefficient for Wednesday in 9 of the 11 markets. For each day, the averages of the 11 coefficients

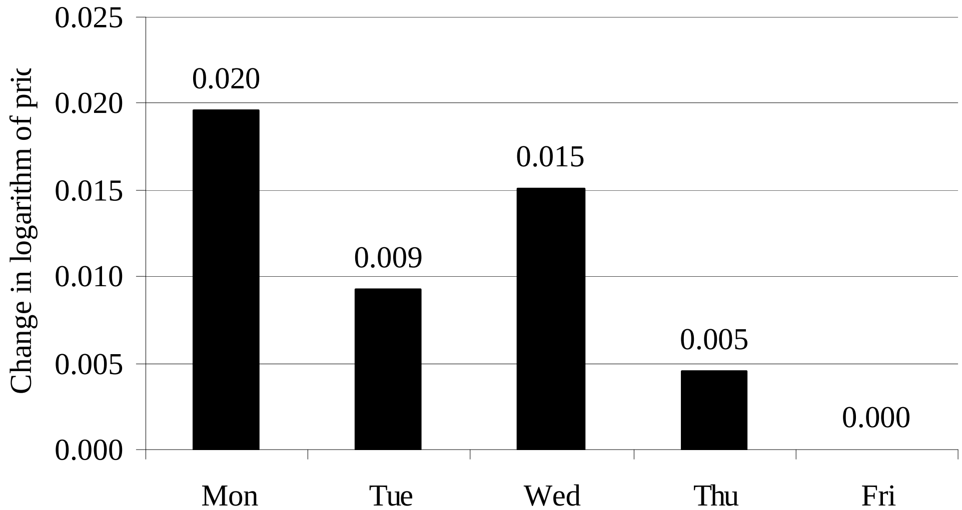


Figure 4.6. Average values of weekday coefficients from 11 natural gas market price series, daily data March 11, 1994–March 25, 2009. Values derived from model output.

from each market are graphed in Figure 4.6. Because the coefficients are from the error correction model (equations 6), the coefficients are interpreted as the change in logarithm of prices from the previous day. Relative to Friday, the day with the largest price change is Monday. One possible reason for Monday being largest is that Monday is used to restock supplies that were depleted over the weekend. The next largest average price change is associated with Wednesday followed by Thursday. These averages could indicate on Wednesday and Thursday traders are getting ready for the weekend.

Using the raw price data, the average weekday change from the previous day in the logarithm of price (Figure 4.7) and price (Figure 4.8) from the 11 natural gas markets are graphed. It is clear from Figure 4.7 that on average the change in logarithm of price

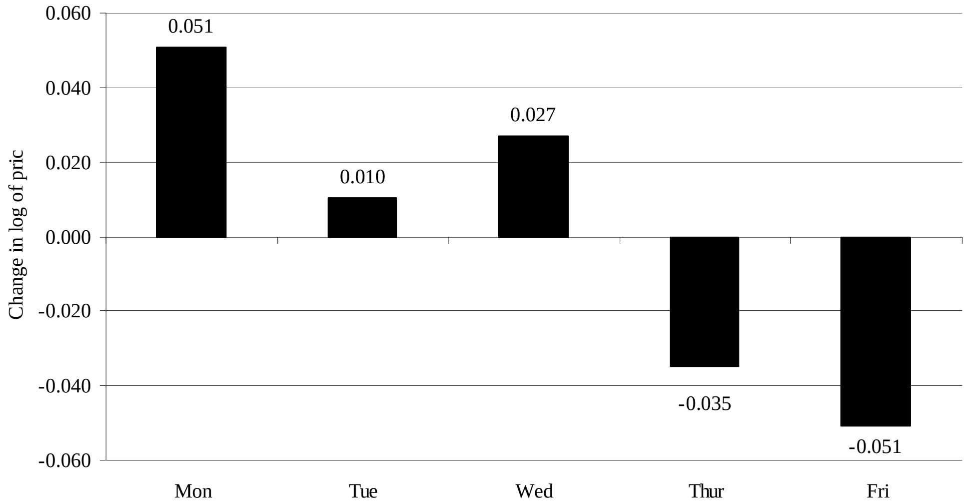


Figure 4.7. Average change in logarithm of price for each weekday from 11 natural gas market price series, daily data March 11, 1994-March 25, 2009. Values derived from raw data.

is positive for Monday, Tuesday, and Wednesday and negative for Thursday and Friday. However, Figure 4.8 shows that the mean values and standard deviations of prices are quite stable across weekdays. Average weekday affects on the change in logarithms of price for the 11 natural gas markets are provided in Table 4.11.

Only 12 of the 44 heating and cooling degree day coefficients are significant at the 0.01% level (Table 4.10). Canada heating degree day has the most significant coefficients with seven out of 11 coefficients being significant. No coefficients associated with Canada cooling degree days are significant. Only two coefficients associated with U. S. heating degree days are significant, and only three coefficients associated with U. S. cooling degree days are significant. Because heating and cooling

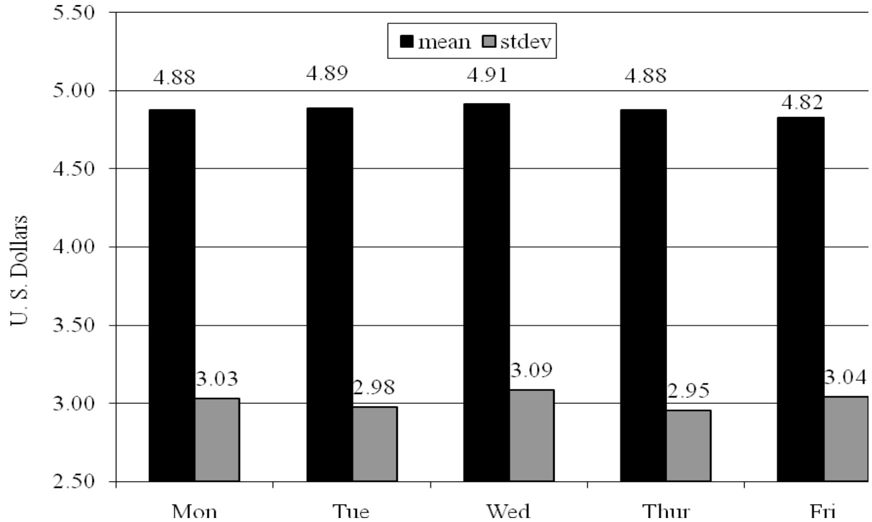


Figure 4.8. Average price and standard deviation for each weekday from 11 natural gas markets, daily data March 11, 1994-March 25, 2009. Values derived from raw data.

degree days variables are correlated individual interpretation may be misleading. As such, the coefficients for each market are not presented.

Seasonal effects determined by first calculating the average coefficients over the 11 markets for CHDD, CCDD, UHDD, and UCDD. These average values are then multiplied by the average heating and cooling degree days by season. For each season the resulting multiplied values are summed (Figure 4.9). The average the change in logarithm of price of natural gas associated with CDD and HDD is largest during the winter. The next largest average change in logarithm of price is associated with the fall followed by spring. The smallest average change occurs during the summer. The larger price change in the winter might be explained by an increase in demand for natural gas because of the increased use of natural gas for heating in the winter.

Table 4.11. Average Weekday Affects on the Change in Logarithms of Price for 11 Natural Gas Market Price Series. Daily Data March 11, 1994–March 25, 2009.

	Mon	Tue	Wed	Thu	Fri
HH	0.016	0.008	0.012	0.005	0.000
CH	0.019	0.007	0.018	0.005	0.000
NY	0.026	0.012	0.021	0.000	0.000
MALI	0.035	0.017	0.019	0.012	0.000
IROQ	0.018	0.010	0.019	0.001	0.000
NIAG	0.018	0.009	0.012	0.006	0.000
DAWN	0.012	0.006	0.008	0.003	0.000
EMPR	0.014	0.009	0.014	0.005	0.000
AECO	0.016	0.011	0.017	0.005	0.000
KING	0.019	0.006	0.013	0.004	0.000
SUMA	0.021	0.008	0.013	0.004	0.000

Average seasonal prices using the raw data are graphed in Figure 4.10. Natural gas average prices are higher in the fall and winter than in the spring and summer. Summer average prices are the smallest. The standard deviations of prices are higher in the fall and winter than in the other two seasons.

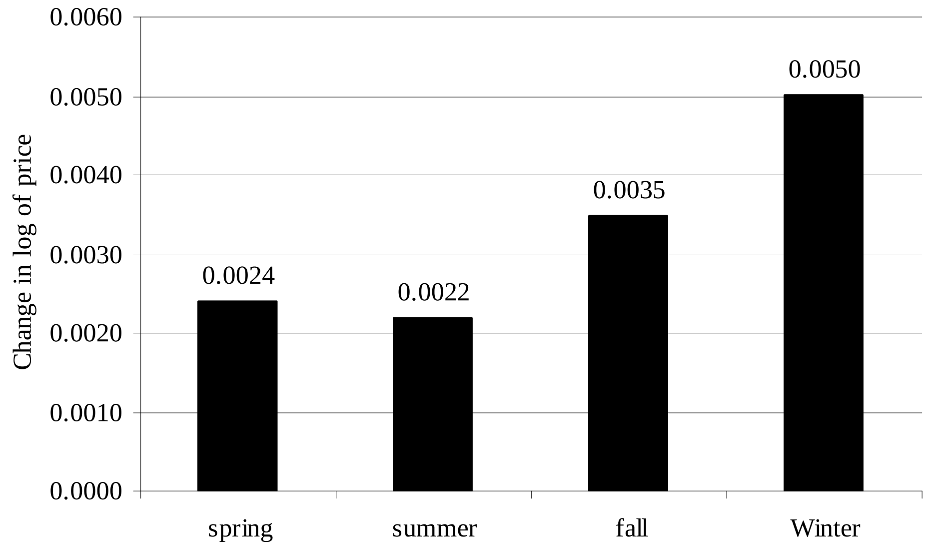


Figure 4.9. Average seasonal effect on change in logarithm of price from 11 natural gas market prices, daily data March 11, 1994–March 25, 2009. Values derived from model output.

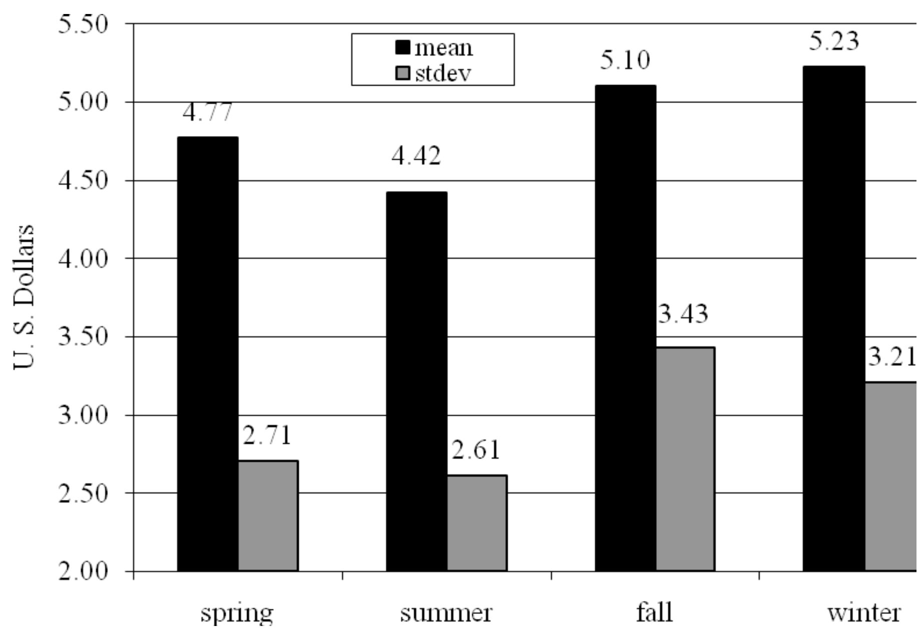


Figure 4.10. Average seasonal price and standard deviation from 11 natural gas markets, daily data March 11, 1994-March 25, 2009. Values derived from raw data.

CHAPTER V

CONCLUSIONS AND DISCUSSION

Given there is no denying the importance of natural gas to the U.S., Canada, and world economies, understanding how natural gas markets in North America interact is valuable to numerous sectors. Deregulation and technological advances in the late 20th century has opened the U.S.'s and Canada's natural gas market to new and extensive interactions. Important practical implications of the extent of market integration include: producer access to market opportunities; consumer access to least-cost supplies; and the price determination process. These and other implications depend on the extent to which markets are linked (King and Cuc 1996). This study's objective is to analyze the efficiency of gas markets in response to price signals, by characterizing the extent of dynamic integration among markets and by investigating each individual markets' role in price discovery. Achieving this objective provides a dynamic picture of daily price information flows among 11 U.S. and Canada natural gas markets.

Advances in causal flows in conjunction with time-series analysis are used to determine the dynamic integration among 11 spot markets in the U.S. and Canada. Because the natural gas price series are non-stationary, a vector error correction model is used as the basis for determining the dynamic relationships among the 11 markets. Directed acyclical graphs provide the contemporaneous causality structure, and innovation accounting illustrates the dynamic or ripple effects among the 11 natural gas spot markets from a shock in a particular market.

Studies attempting to model the dynamic natural gas market structure show some conflicting results. Cuddington and Wang (2006) and King and Cuc (1996) show there is an east-west split, whereas Serletis (1997) does not. A study by Park, Mjelde, and Bessler (2008) report that price determination is influenced by regions of excess demand and supply. Some previous gas market studies have used monthly data (King and Cuc 1996, Kleit 1998, Spulber and Doane 1994), whereas, this study uses daily data to more accurately capture the speed of market adjustments. Data used for this study span 15 years (1994-2009) following major deregulation policies. Further, a greater share of Canadian markets compared to U.S. markets is included in this study, which is not the case in previous studies. It is important to include these additional markets because the U.S. and Canada trade a large volume of natural gas. These considerations are improvements upon past studies which allow for a better understanding of the dynamic integration among natural gas markets of the U.S. and Canada and their role in price discovery.

This study finds that no one market is a clear price leader. Directed acyclical graph results indicate that Dawn, Onatario is exogenous in contemporaneous time, meaning that it does not receive price information from other markets. Sumas, Washington is an information sink and contributes very little to the price variation in other markets. Dawn and Henry Hub, Louisiana both play a major role in the price variation of other markets at a 30 day horizon. This supports the idea that both regions of excess demand and supply influence the price determination process. Henry Hub is a region of excess supplies and Dawn is a region of excess demand. Surprisingly, a shock in AECO, Alberta market has little impact on the U.S. markets. This was not the case in Park, Mjelde, and Bessler (2008) where they show AECO as being an important player for price discovery in the natural gas markets. Park, Mjelde, and Bessler (2008) only included one western Canadian market which may lead to their conclusion that AECO is important in price discovery. Henry Hub's role in the price determination process mirrors the flow of natural gas from Henry Hub to the midwest and northeast with only a small amount going to the west (Figure 2.1). Further, its determined that markets located nearby one another are important in the price discovery process. Nearby markets have a larger impact on each others' percentage of price variation as seen in the forecast error variance decompositions than markets located further apart. Similarly, the impulse response functions show that markets located nearby respond in like manner. Although, as noted there are some regional differences, no clear east-west split is found.

Time series properties of the price series from the 11 natural gas markets provide information into the markets' dynamic characteristics. The tests of weak exogeneity, for example, are rejected for every market. This suggests that each market's prices are responsive in the short-run to perturbations (deviations) in the long-run relationships (co-integrating space). Tests of exclusion reject the null hypothesis for all markets that a particular market is not in the co-integration space. Further, there are nine long-run cointegration relationships that exist in the data. These findings provide strong evidence that the 11 natural gas markets are integrated.

Each of the 11 natural gas markets are involved in the price discovery process, and are part of the long-run equilibrium as it pertains to natural gas market prices. It appears that evolving deregulation policy and technological advances have led to an integrated natural gas market in the U.S. and Canada. Hence, supporting the economic theory of the law of one price, all markets contribute to price determination. It is evident by the impulse response functions and forecast error variance decompositions that the degree to which these markets are integrated varies across markets and geographical regions.

Limitations and Further Research

Issues not addressed may provide additional insights into the dynamics of the natural gas markets. Inclusion of Mexican markets and southwestern markets, such as southern California, would allow for a more complete picture. Data limitations did not allow for inclusion of these markets. Adding central U.S. and Canada markets to this study may also be informative. Past studies showed that markets near Texas and Oklahoma behaved like one large market, so only Henry Hub was considered in this study. Similarly, Opal market located in Wyoming was shown to be an information sink, therefore it was also not considered in this study. Natural gas markets, however, are continually evolving and inclusion of these markets in the future may contribute to price information. Construction on a 42 inch gas pipeline began July 31, 2010 to connect

Opal market to Malin, Oregon market (Ruby Pipeline LLC. 2010) is an example of a perpetual changing market environment.

Shifts in the end use of natural gas are another cause of an ever developing natural gas market. Interdependency among other markets is evident. Increasing use of natural gas for electricity production indicates including electricity markets in price discovery may be important. The push for natural gas powered vehicles may also change price discovery in the natural gas markets. Futures markets may provide information for price discovery. Further research should include not only natural gas futures but other related markets. Contractual arrangements may also be a fruitful avenue of future research.

Exogenous factors considered in this study are weather, weekday, and seasonality. Factors such as storage, future markets, types of end use, and supply side issues such as exploration, production, known supplies should be considered in future studies. Such studies, however, most likely could not use daily prices because of limitations on the other data. In addition to including other exogenous variables, determining whether or not financial exchange rates are a factor in market integration is important. Extending the investigation to explain more fully the contributions of seasonality, weather conditions, and weekday on the price of natural gas could be an area of future research.

Finally, methods to provide contemporaneous structure and carry out time series analysis, as well as computer capacities are advancing. Additional research to improve contemporary structure and time series analysis is warranted, especially on how to handle a large number of series. Studying the higher moments, kurtosis, or skewness in addition to other areas currently undiscovered may lead to improved methods of determining causal structure. Such methodological advances in time series and causal modeling will have benefits to numerous disciplines.

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APPENDIX A

Figures A.1 – A.8 represent the contemporaneous causal relationship between AECO, Chicago, Dawn, Empress, Henry Hub, Iroquois, Kingsgate, Malin, Niagara, New York, and Sumas Hubs. GES algorithm results are presented below using a penalty discount equal to 1. All edges are directed by either the GES algorithm or assumptions. Each model's chi-squared and BIC values are equal (chi-squared of 29.05 and BIC of -152.99).

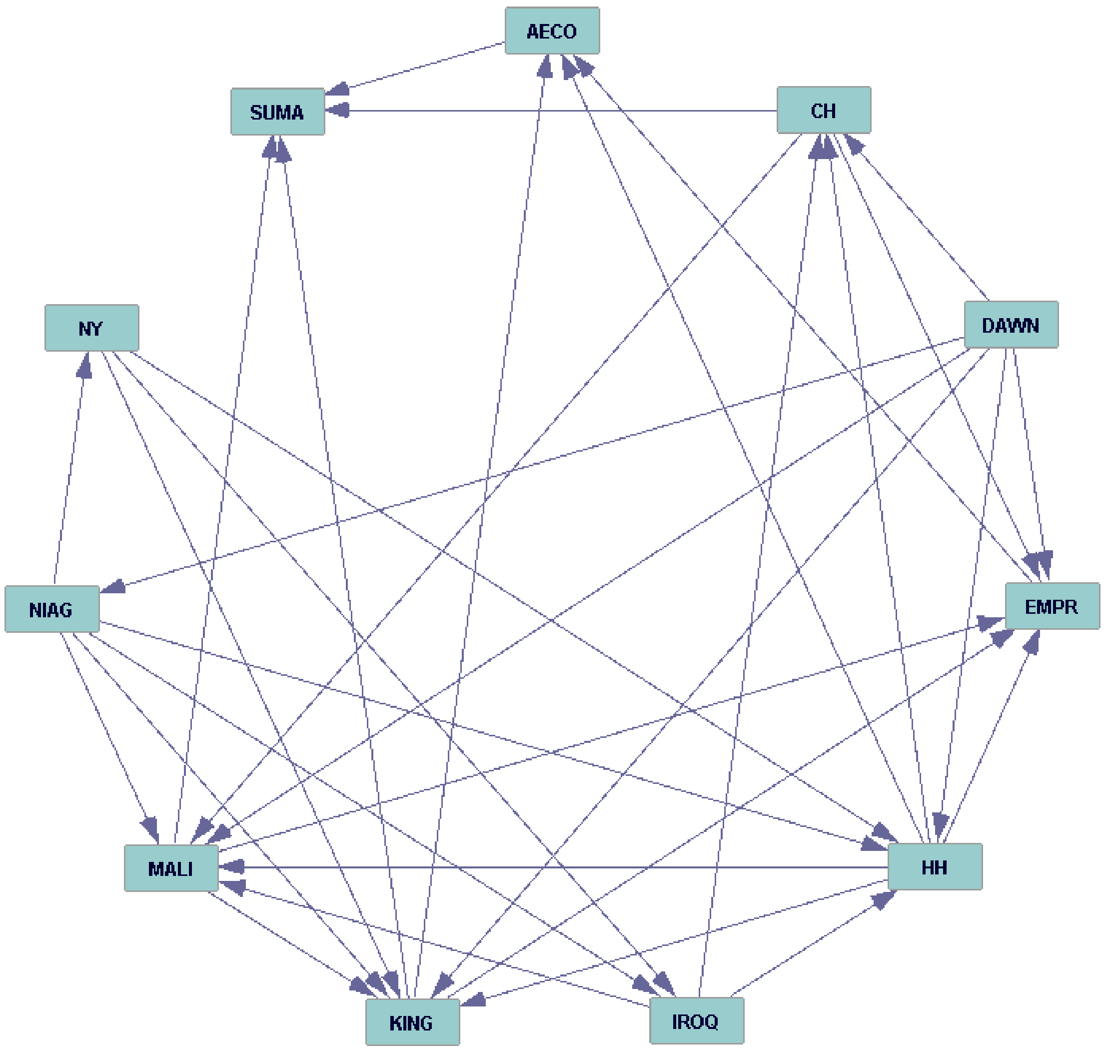

Figure A.1. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Dawn to Iroquois chain (used for analysis).

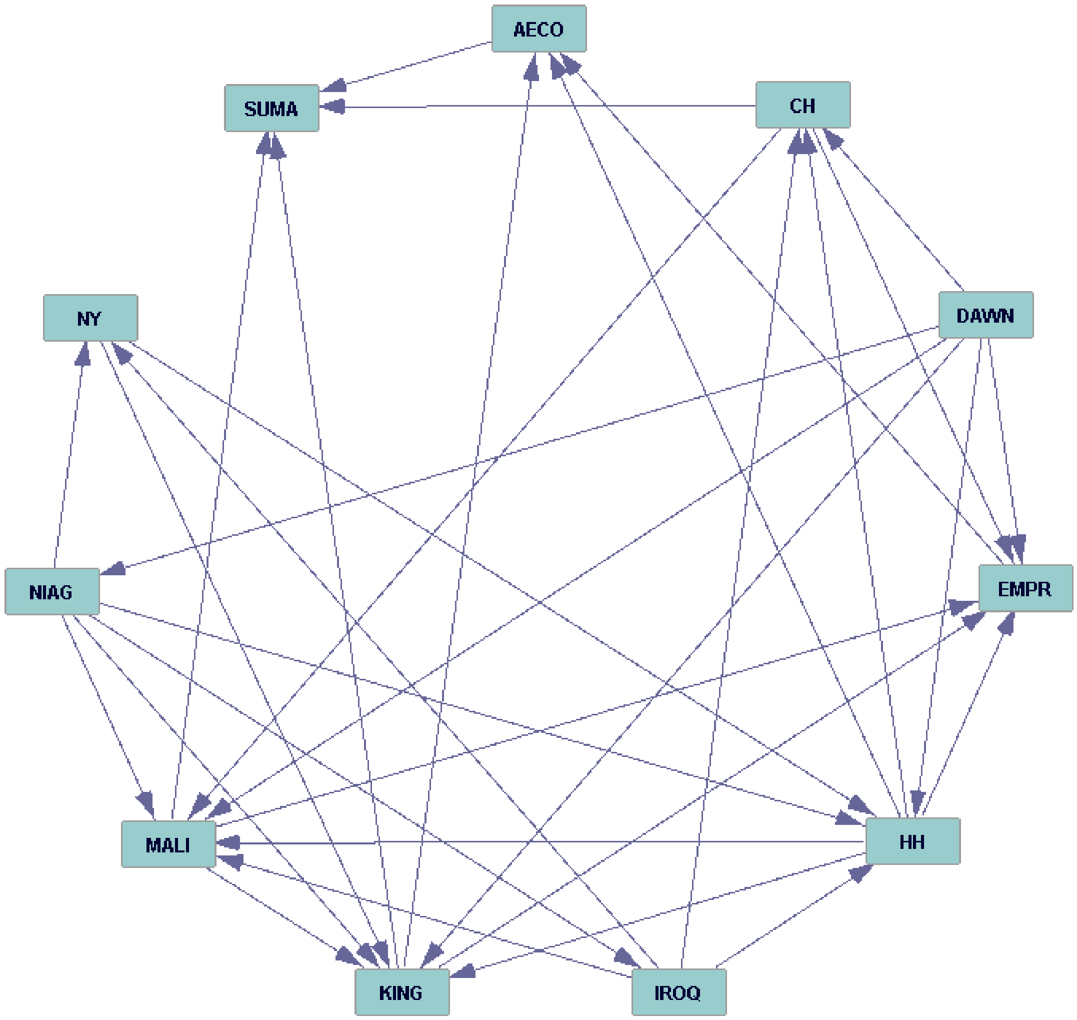

Figure A.2. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Dawn to New York chain.

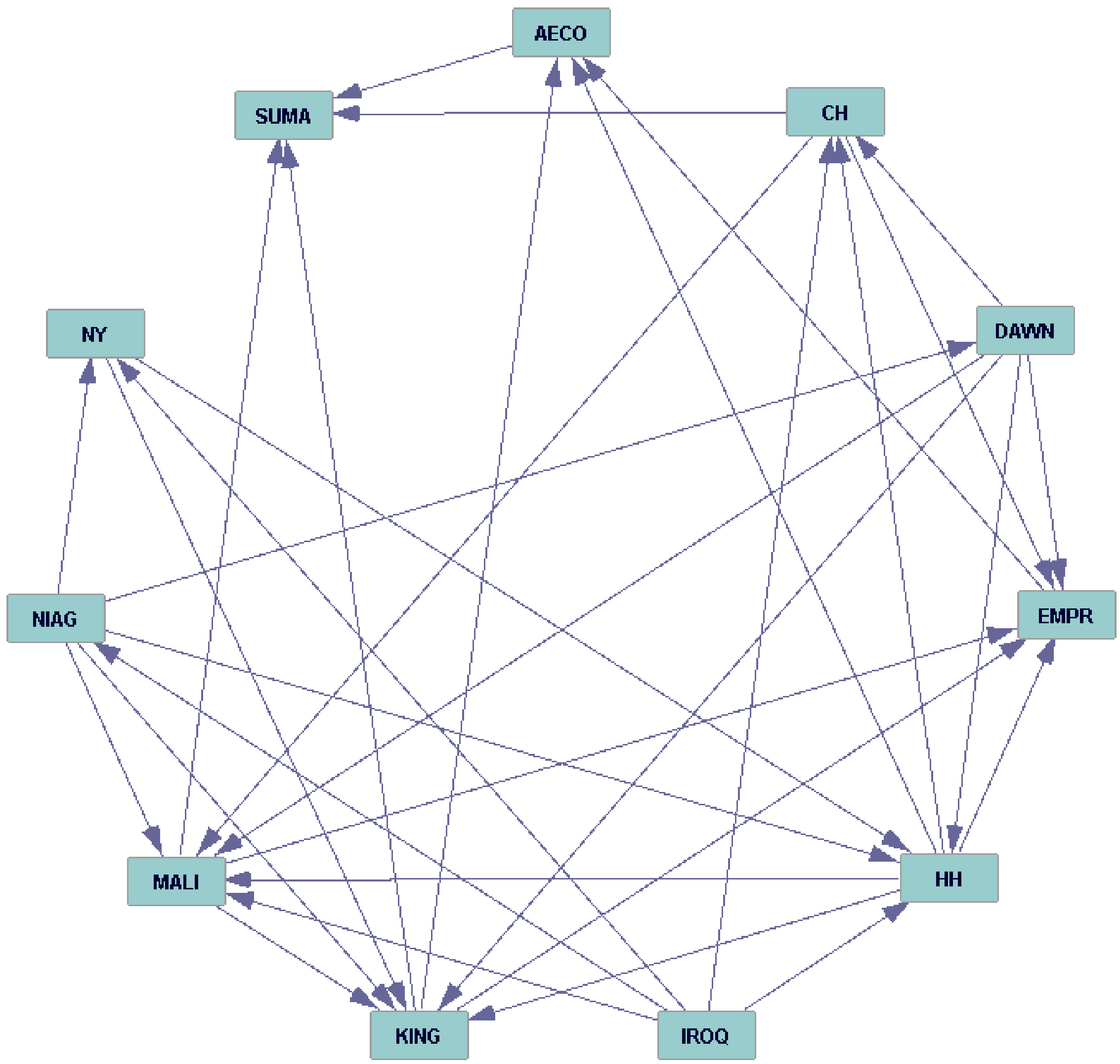

Figure A.3. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Iroquois fork with directed edge Niagara to New York.

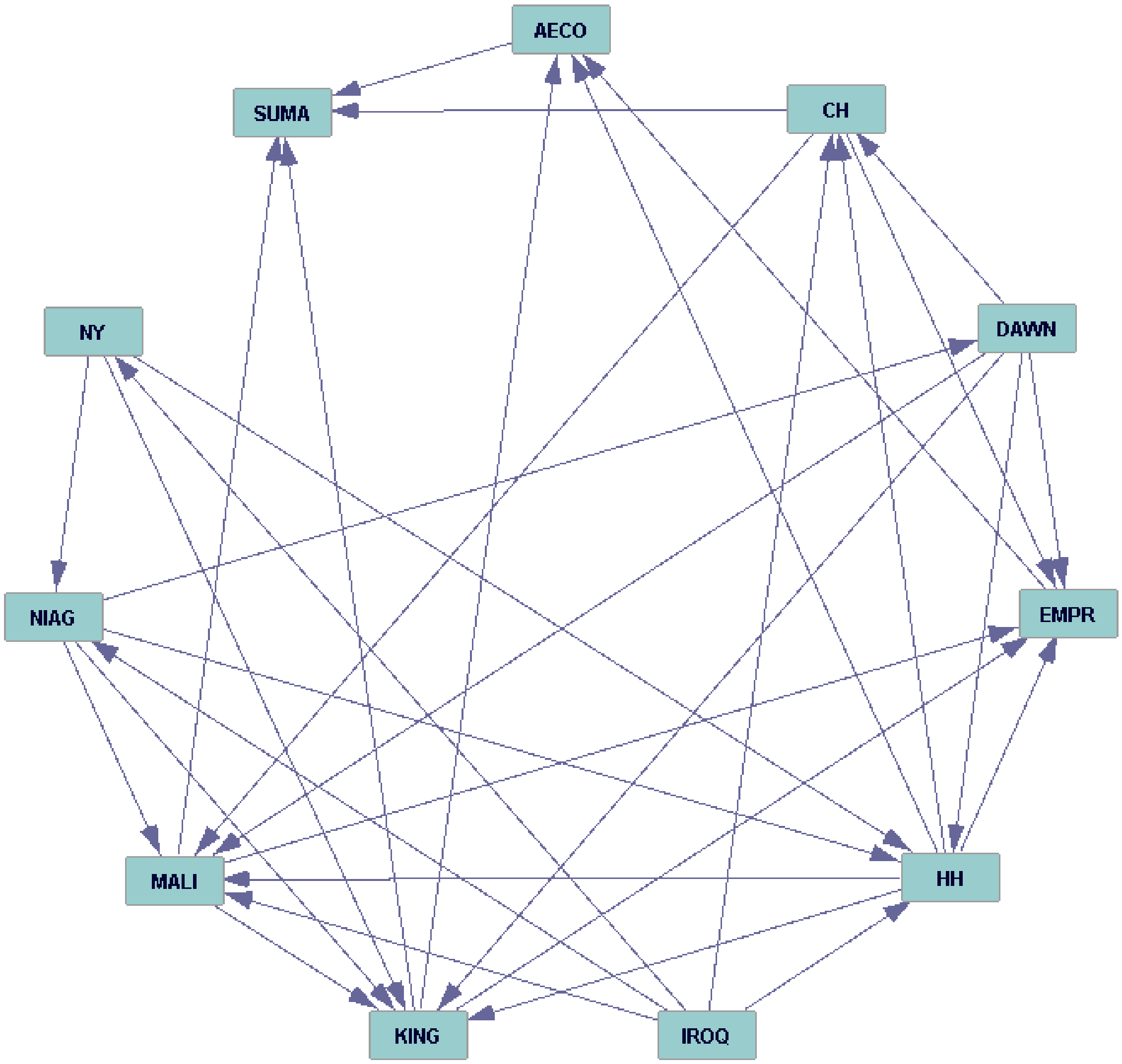

Figure A.4. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Iroquois fork with directed edge New York to Niagara.

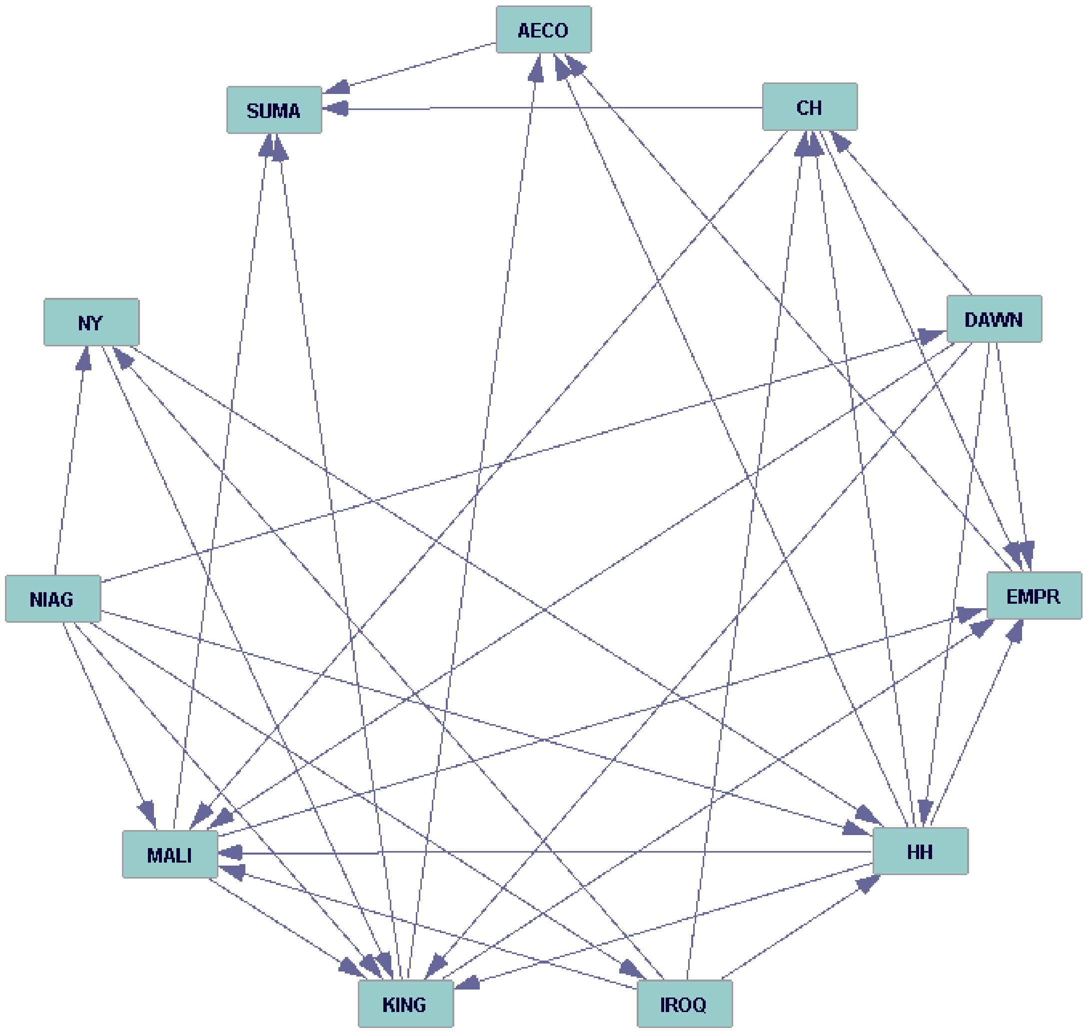

Figure A.5. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Niagara fork with directed edge Iroquois to New York.

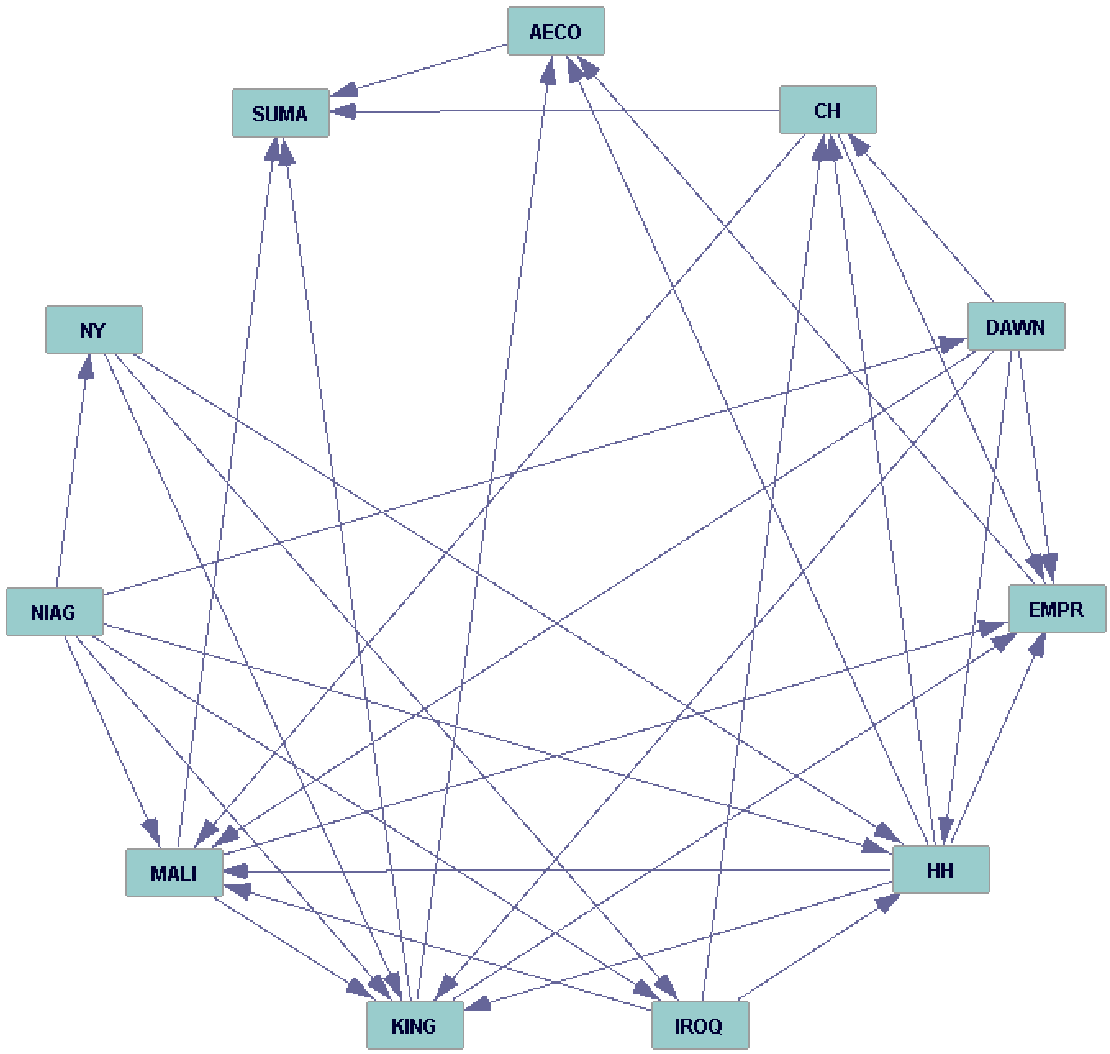

Figure A.6. Contemporaneous causal relations among the 11 Natural Gas Markets assuming Niagara fork with directed edge New York to Iroquois.

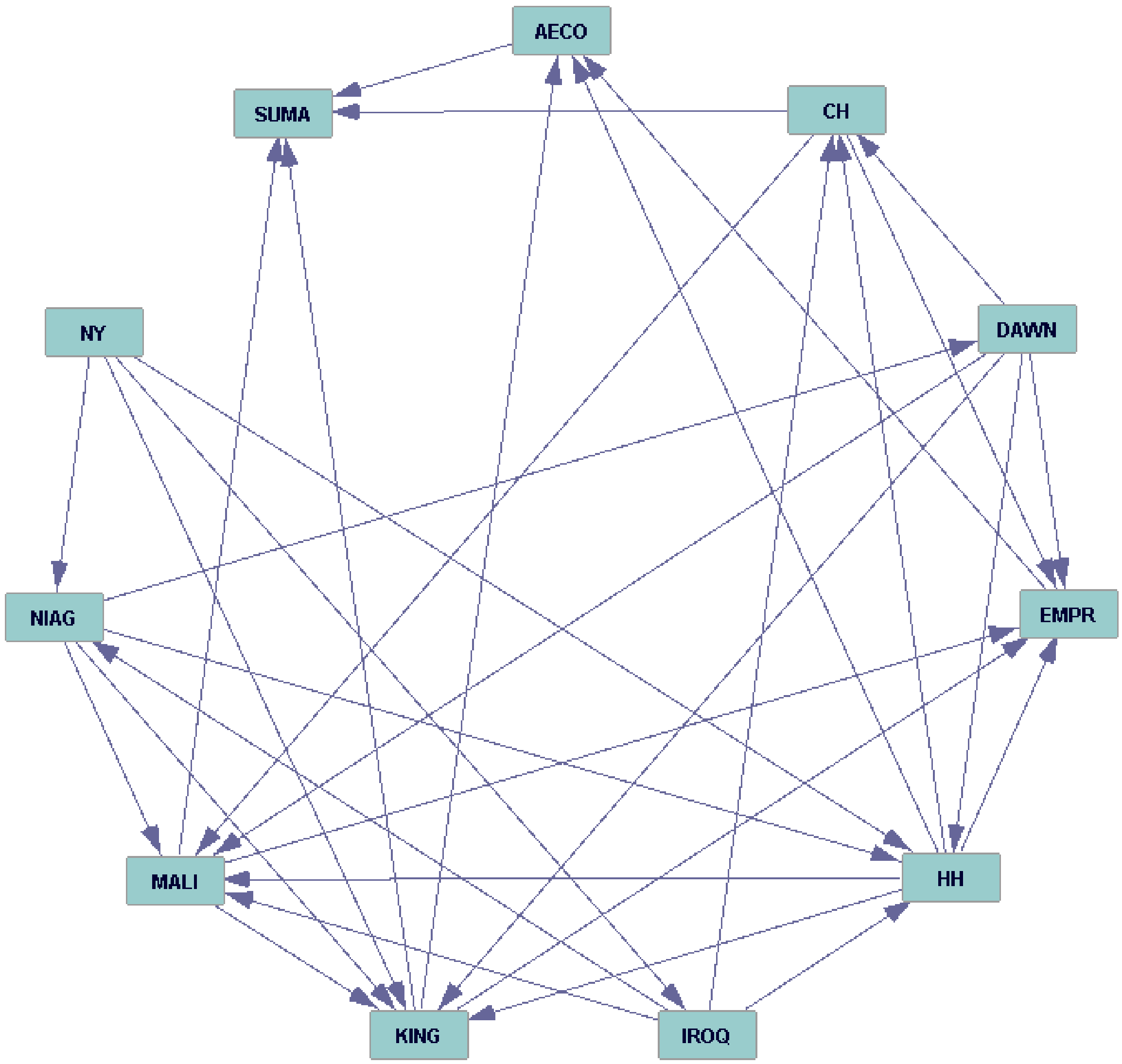

Figure A.7. Contemporaneous causal relations among the 11 Natural Gas Markets assuming New York fork with directed edge Iroquois to Niagara.

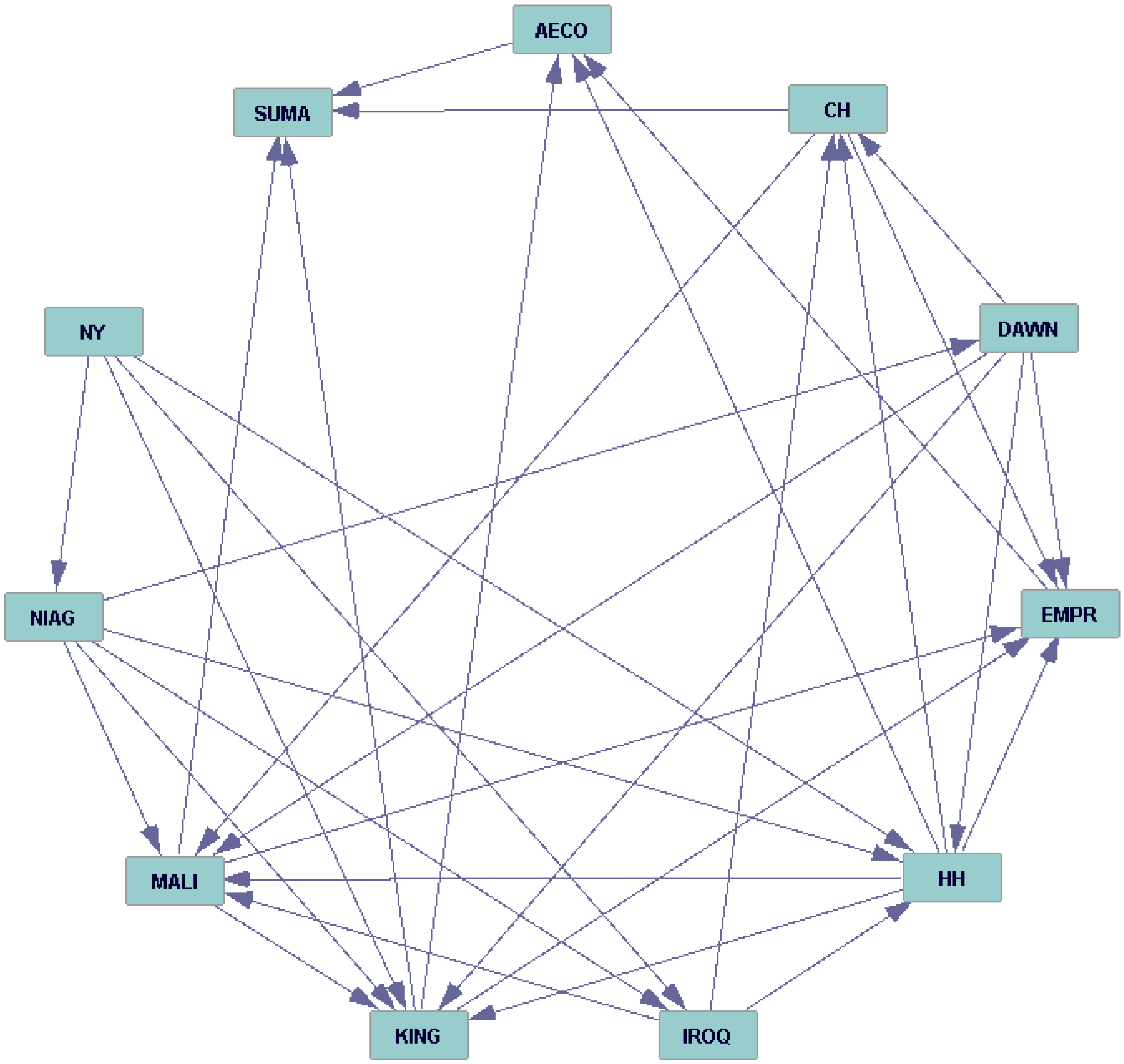

Figure A.8. Contemporaneous causal relations among the 11 Natural Gas Markets assuming New York fork with directed edge Niagara to Iroquois.

APPENDIX B

Impulse Response Functions (Figures B.1 – B.8) depict normalized responses of Henry Hub, Chicago, New York, Malin, Iroquois, Niagara, Dawn, Empress, AECO, Kingsgate, and Sumas markets (left side), to a one time shock (positive) in every other series listed at the top of each column over a horizon of 30 trading days. Figures B.1 – B.8 correspond to the contemporaneous structures provided in Figures A.1 – A.8.

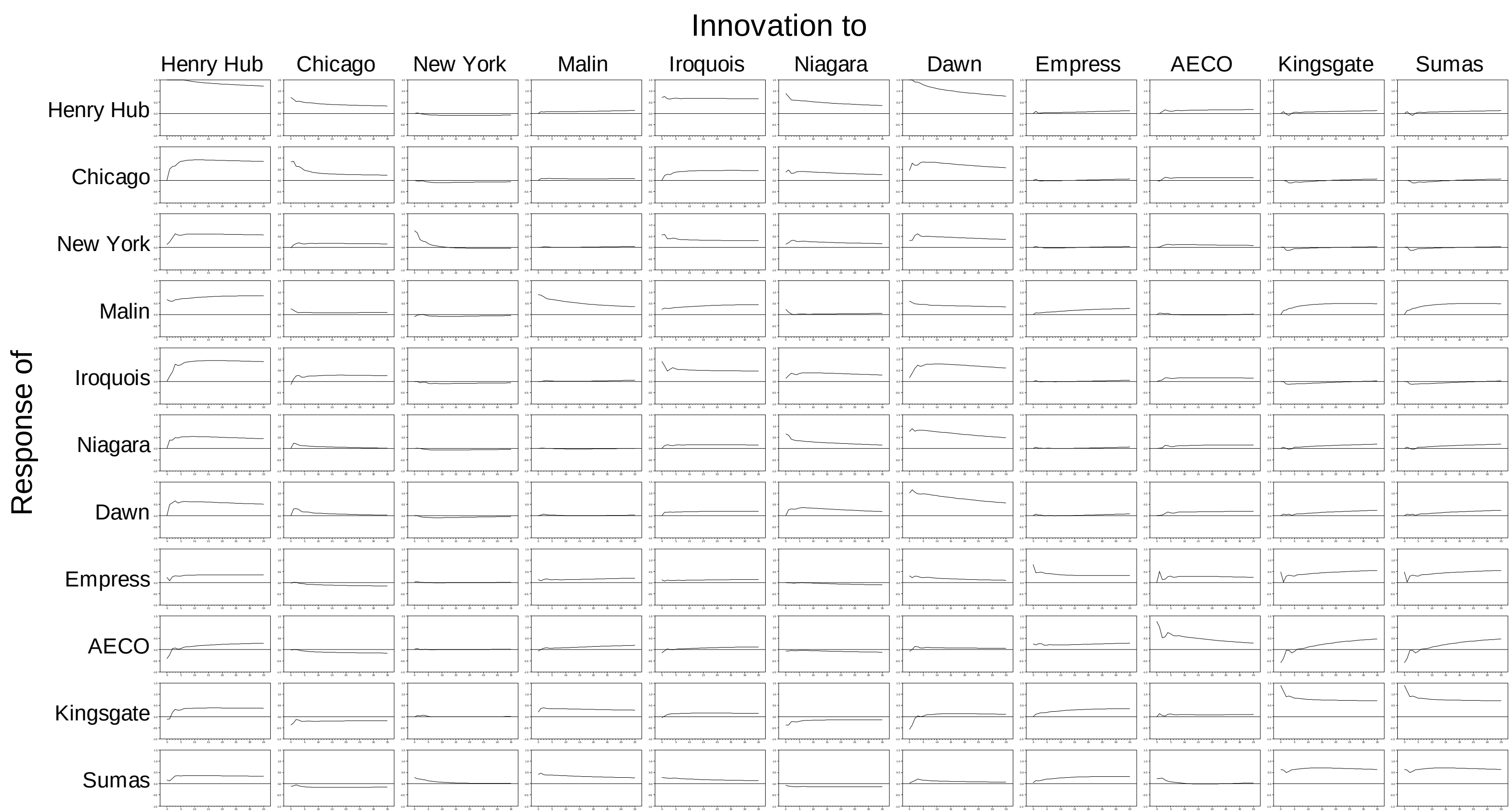

Figure B.1. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Dawn to Iroquois chain (used for analysis) as the contemporaneous causal relation.

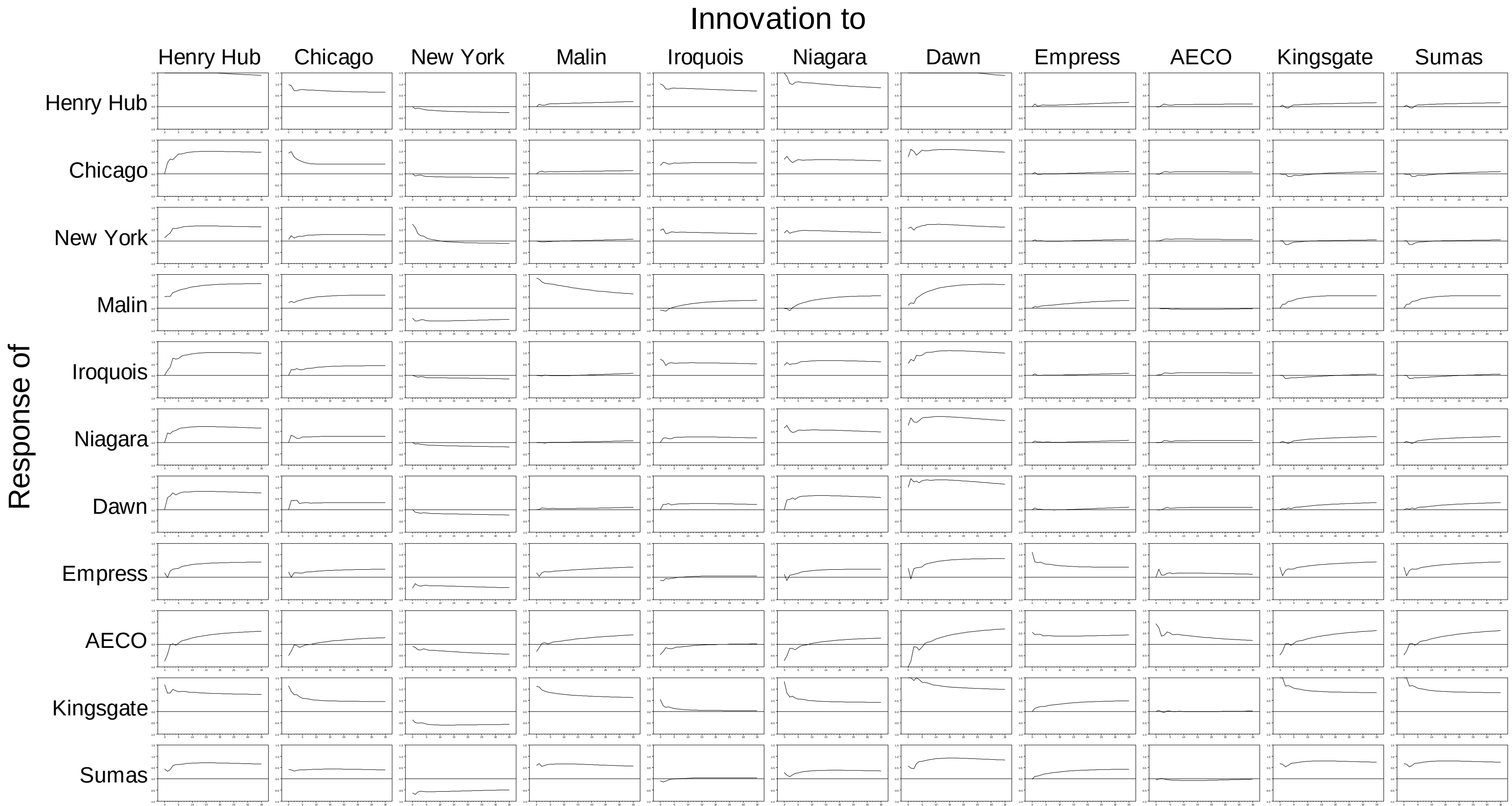

Figure B.2. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Dawn to New York chain as the contemporaneous causal relation.

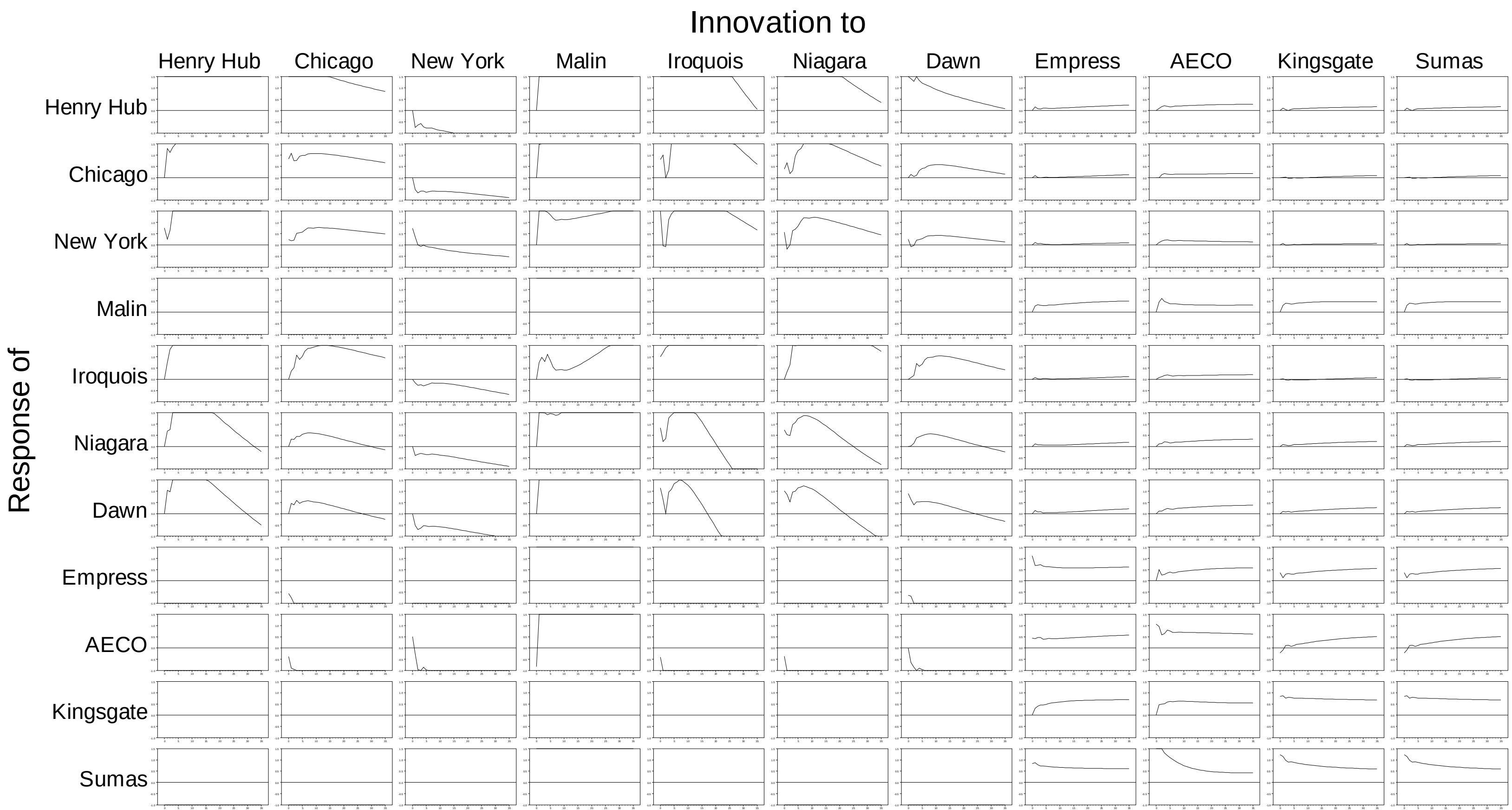

Figure B.3 Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Iroquois fork with directed edge Niagara to New York as the contemporaneous causal relation.

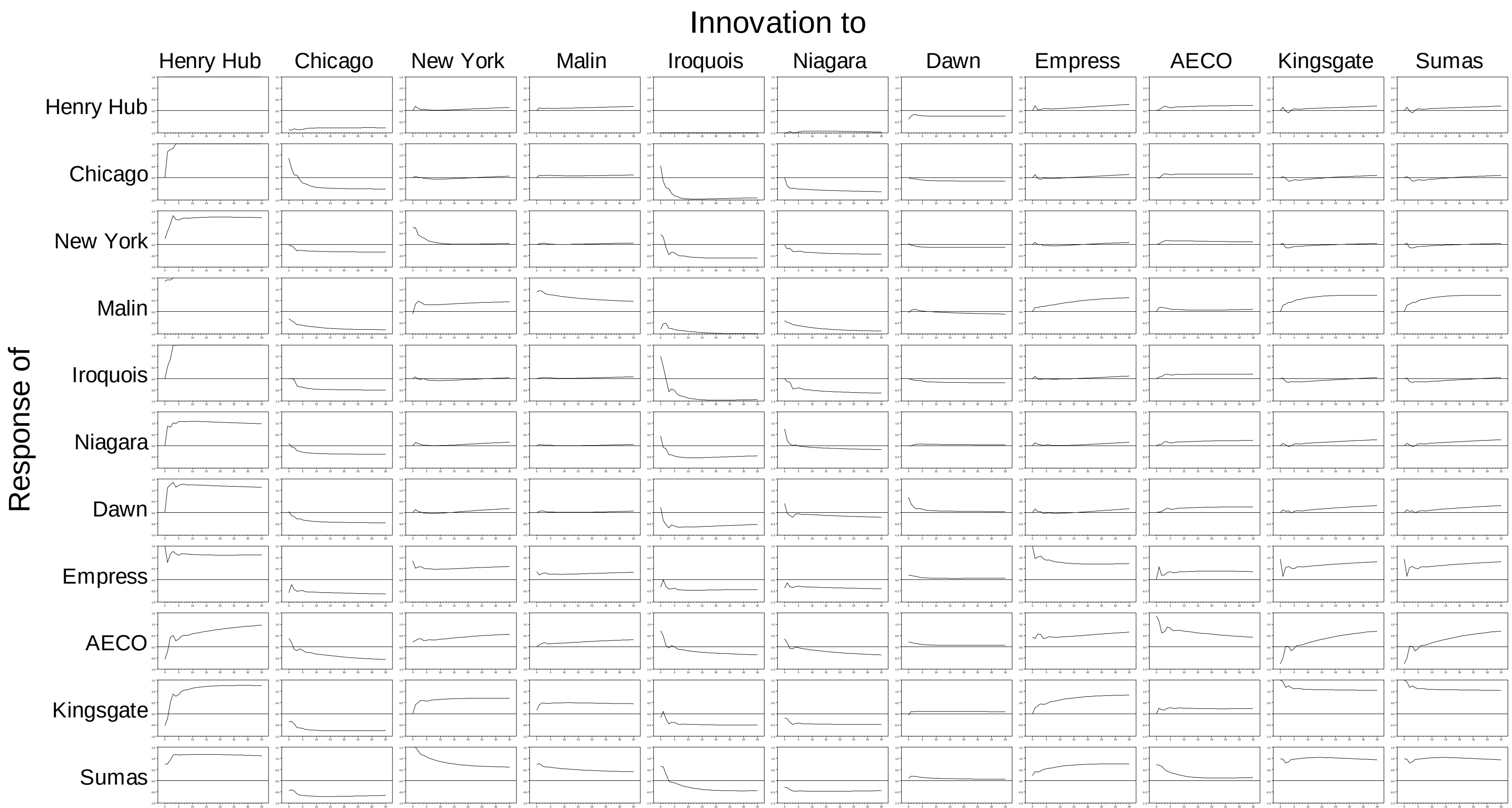

Figure B.4. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Iroquois fork with directed edge New York to Niagara as the contemporaneous causal relation.

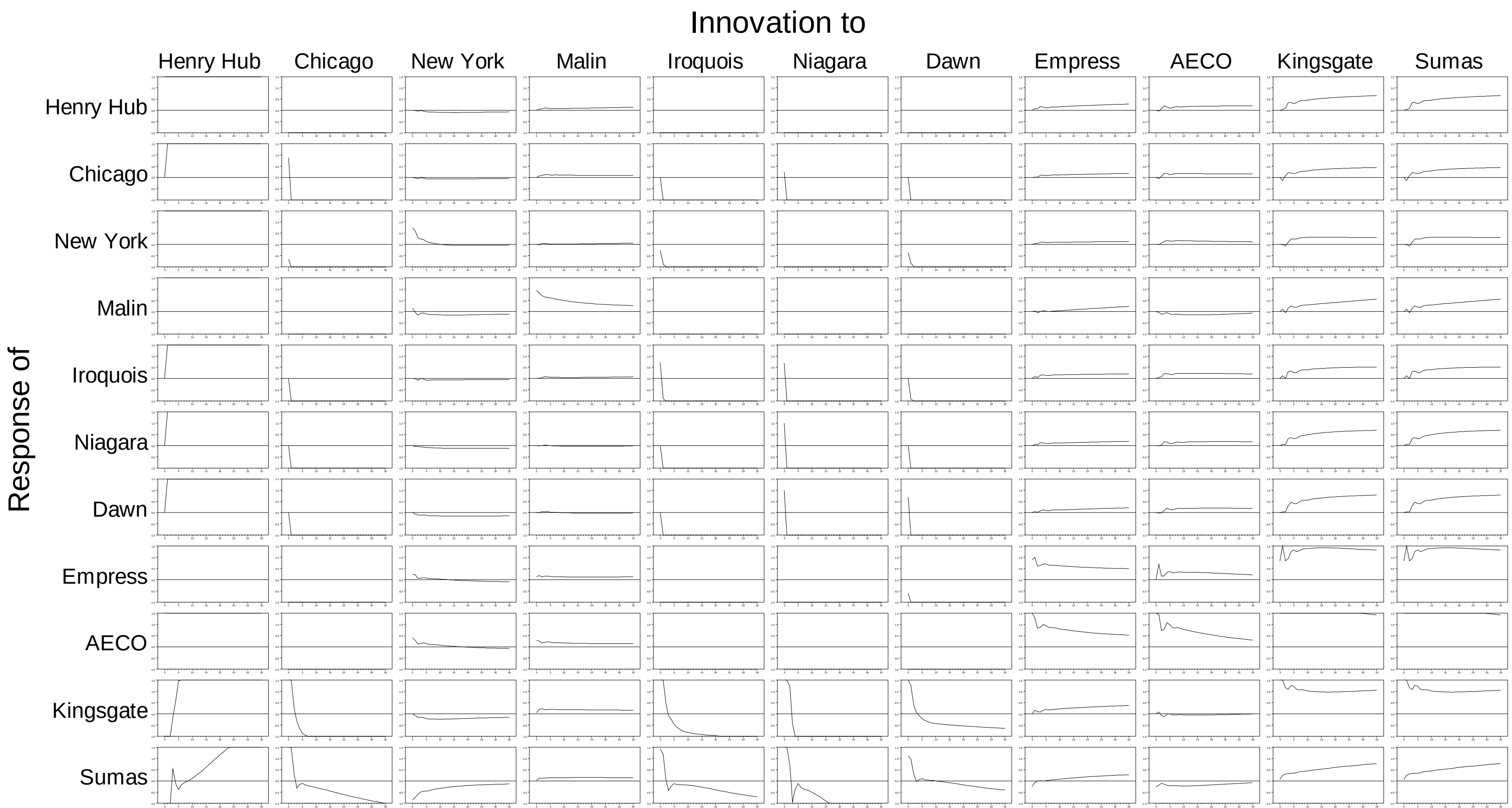

Figure B.5. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Niagara fork with directed edge Iroquois to New York as the contemporaneous causal relation.

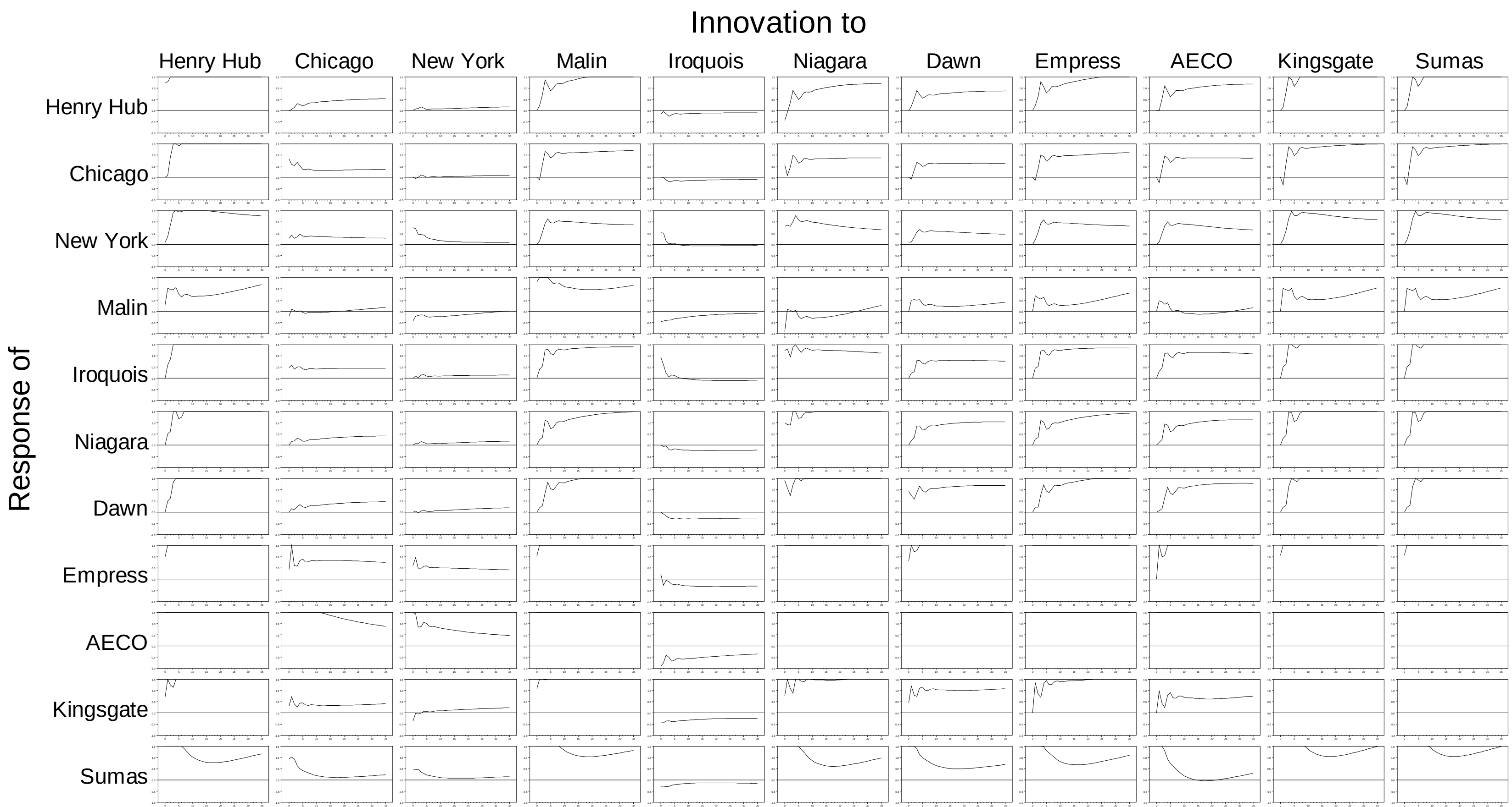

Figure B.6. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming Niagara fork with directed edge New York to Iroquois as the contemporaneous causal relation.

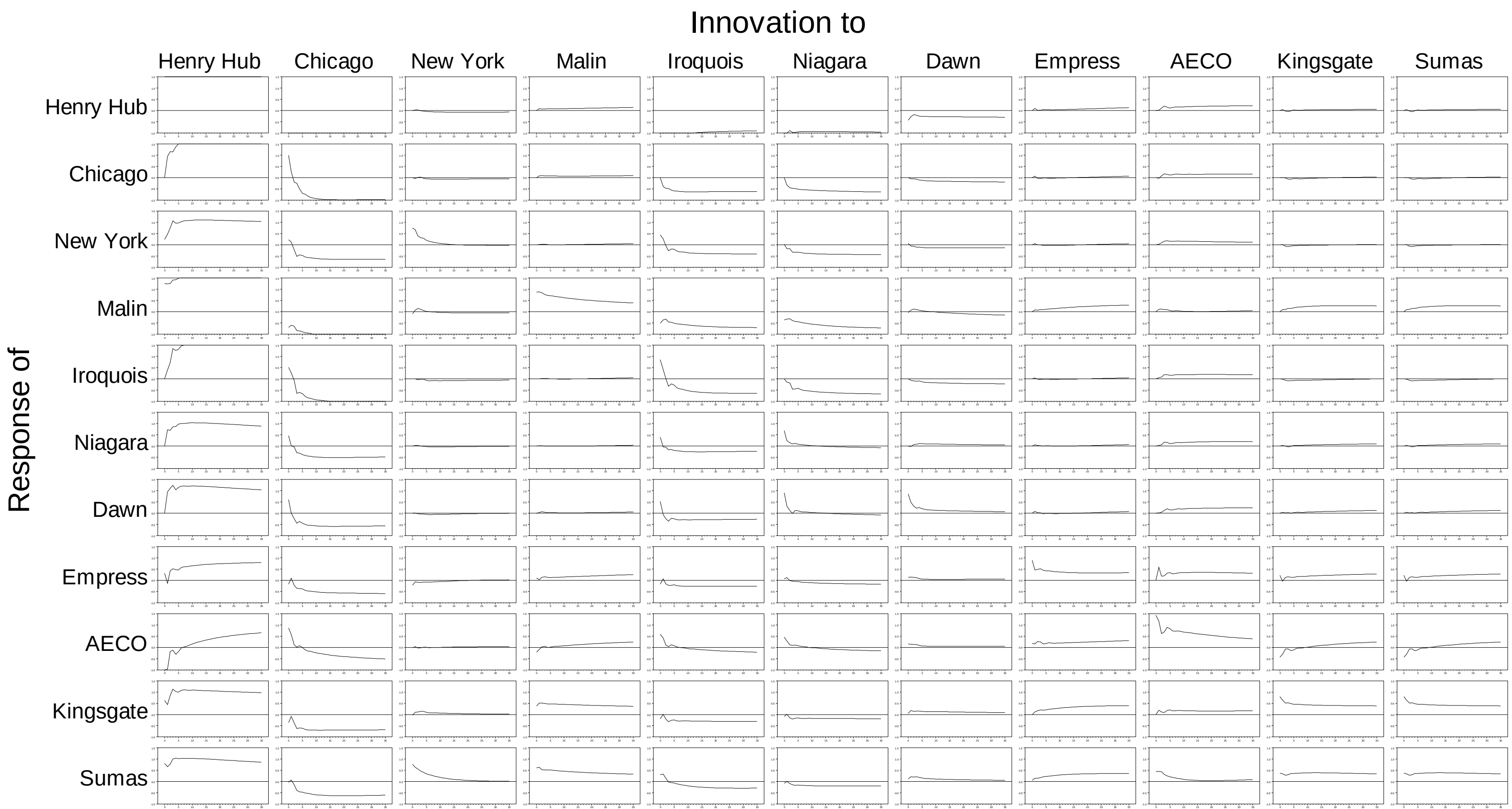

Figure B.7. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming New York fork with directed edge Iroquois to Niagara as the contemporaneous causal relation.

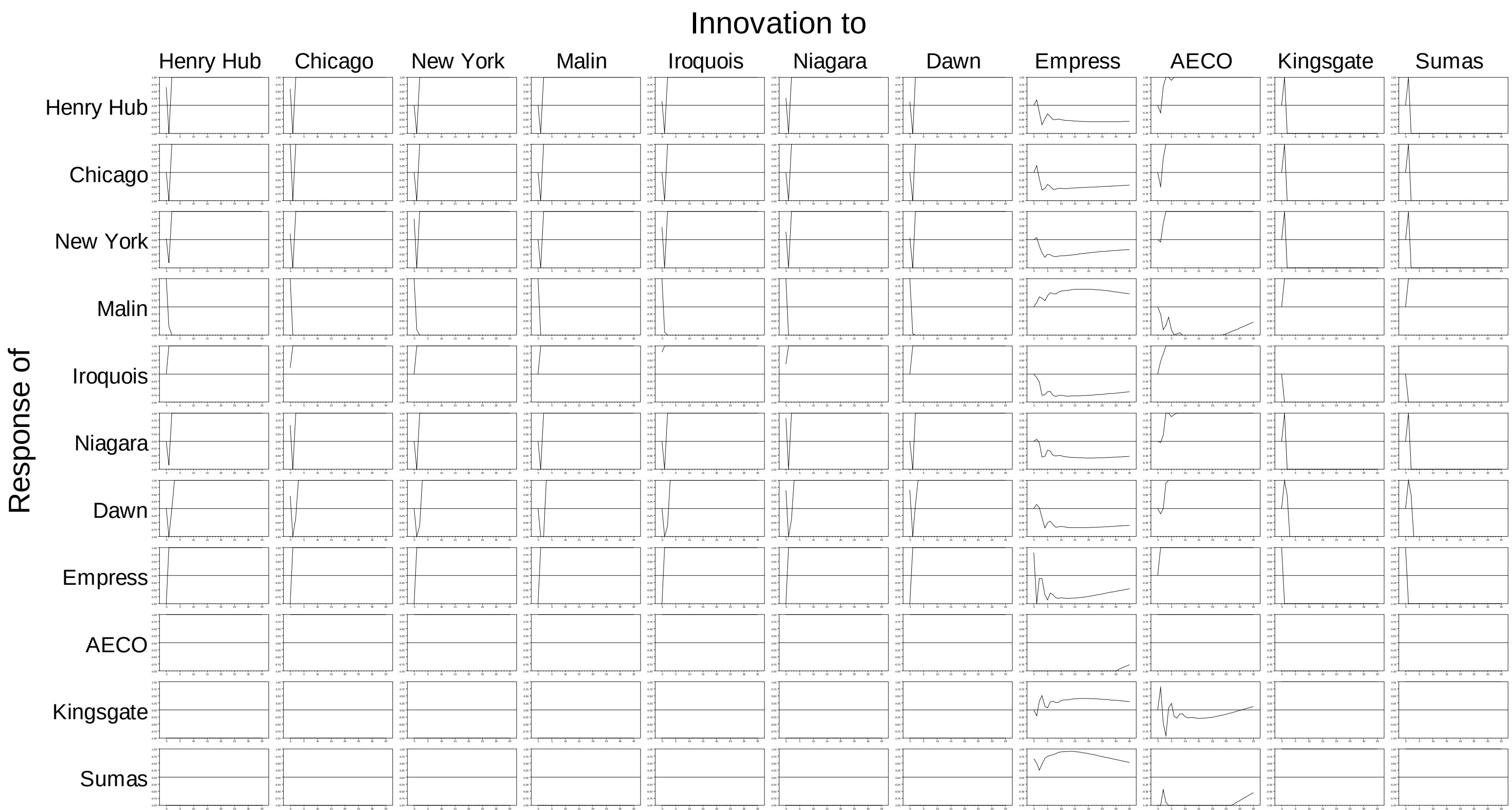

Figure B.8. Responses of 11 U.S. and Canada natural gas market prices to a single innovation (shock) in each series assuming New York fork with directed edge Niagara to Iroquois as the contemporaneous causal relation.

APPENDIX C

Forecast Error Variance Decompositions (Tables C.1 – C.8) summarize the percentage of price uncertainty at a given market, located as subheadings in the table, due to innovations in Henry Hub, Chicago, New York, Malin, Iroquois, Niagara, Dawn, Empress, AECO, Kingsgate, and Sumas markets listed at the top of each column over a horizon of zero to thirty trading days. Tables C.1 – C.8 correspond to the contemporaneous causal structures provided in Figures A.1 – A.8.

Table C.1. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Dawn to Iroquois Chain.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
Henry Hub, Louisiana (HH)											
0	44.04	6.50	0.00	0.00	6.34	10.00	33.12	0.00	0.00	0.00	0.00
1	43.63	6.12	0.00	0.04	7.16	9.06	33.89	0.05	0.00	0.04	0.02
30	48.20	4.64	0.16	0.20	10.86	6.28	28.86	0.11	0.48	0.15	0.07
Chicago Citygate, Illinois (CH)											
0	0.00	67.16	0.00	0.00	0.00	13.85	18.99	0.00	0.00	0.00	0.00
1	9.22	48.94	0.04	0.20	1.63	12.29	27.54	0.11	0.04	0.00	0.01
30	42.36	9.24	0.33	0.33	9.79	6.97	29.92	0.04	0.81	0.14	0.05
Transco Z6 NY, New York (NY)											
0	1.56	0.09	55.95	0.00	30.98	1.97	9.45	0.00	0.00	0.00	0.00
1	4.00	0.72	49.14	0.00	32.72	3.17	10.03	0.09	0.01	0.02	0.11
30	40.53	3.73	5.41	0.06	16.07	6.75	25.41	0.05	1.58	0.24	0.17
Malin, Oregon (MALI)											
0	24.75	3.73	0.64	44.20	3.06	2.97	20.64	0.00	0.00	0.00	0.00
1	24.07	2.98	0.38	45.32	3.93	1.86	19.17	0.15	0.10	0.85	1.19
30	40.09	0.68	0.35	20.97	9.47	0.19	11.49	2.25	0.04	12.46	2.02
Iroquois, New York (IROQ)											
0	0.00	2.16	0.00	0.00	92.34	2.32	3.18	0.00	0.00	0.00	0.00
1	3.16	1.95	0.00	0.00	78.97	5.50	10.16	0.12	0.11	0.00	0.02
30	42.41	3.85	0.34	0.04	16.06	6.98	28.65	0.02	1.39	0.25	0.03
Niagara, Ontario (NIAG)											
0	0.00	0.00	0.00	0.00	0.00	42.17	57.83	0.00	0.00	0.00	0.00
1	6.13	2.28	0.01	0.01	0.68	32.89	57.63	0.12	0.01	0.14	0.10
30	26.79	0.96	0.34	0.02	2.87	10.49	54.26	0.08	2.10	1.63	0.46
Dawn, Ontario (DAWN)											
0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0
1	8.9	3.3	0.0	0.0	0.8	2.3	84.3	0.2	0.0	0.2	0.1
30	27.6	1.3	0.5	0.0	2.5	6.4	57.4	0.1	2.1	1.7	0.5
Empress Spot, Alberta (EMPR)											
0	5.18	0.08	0.07	1.77	1.25	0.00	8.60	61.32	0.00	21.73	0.00
1	4.03	0.06	0.12	1.61	1.16	0.03	8.81	54.07	15.16	14.84	0.11
30	17.41	2.08	0.02	3.74	2.23	0.52	5.78	23.15	11.88	30.48	2.73
AECO C Spot, Alberta (AECO)											
0	7.91	0.02	0.02	0.21	1.00	0.17	0.31	2.77	71.69	15.92	0.00
1	6.43	0.01	0.06	0.13	0.71	0.21	0.19	2.94	74.57	14.67	0.08
30	7.91	2.38	0.02	2.46	1.12	0.96	1.09	9.68	56.50	14.88	2.99
Kingsgate, British Columbia (KING)											
0	0.46	5.48	0.02	1.64	0.08	5.52	12.26	0.00	0.00	74.54	0.00
1	0.50	4.94	0.06	3.84	0.06	6.36	10.44	0.26	0.39	72.45	0.70
30	11.04	3.63	0.03	9.35	1.80	2.92	2.35	6.89	0.63	56.11	5.26
Sumas, Washington (SUMA)											
0	1.56	0.98	4.81	10.39	4.68	0.30	0.07	0.11	2.83	25.17	49.11
1	1.32	0.82	4.17	12.47	4.65	0.61	0.23	0.62	3.19	25.37	46.55
30	11.19	2.41	0.93	11.20	3.71	1.77	1.20	7.19	0.67	43.68	16.04

Table C.2. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Dawn to New York Chain.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
Henry Hub, Louisiana (HH)											
0	29.59	6.92	0.00	0.00	7.19	16.11	40.19	0.00	0.00	0.00	0.00
1	29.36	6.97	0.03	0.04	7.19	15.38	40.95	0.05	0.00	0.02	0.01
30	32.33	6.59	0.56	0.31	8.00	13.35	38.37	0.15	0.11	0.18	0.05
Chicago Citygate, Illinois (CH)											
0	0.00	43.51	0.00	0.00	6.82	20.95	28.72	0.00	0.00	0.00	0.00
1	4.74	34.57	0.16	0.13	7.57	19.15	33.55	0.09	0.02	0.01	0.01
30	29.92	9.30	0.69	0.40	8.41	13.46	37.37	0.07	0.23	0.12	0.05
Transco Z6 NY, New York (NY)											
0	1.50	0.35	44.61	0.00	18.22	10.09	25.22	0.00	0.00	0.00	0.00
1	3.28	2.35	34.51	0.02	19.66	13.27	26.69	0.11	0.00	0.00	0.11
30	29.66	5.36	3.17	0.08	10.91	14.16	35.82	0.07	0.42	0.20	0.15
Malin, Oregon (MALI)											
0	11.08	2.59	8.52	76.77	0.28	0.00	0.77	0.00	0.00	0.00	0.00
1	11.05	3.17	10.86	71.18	0.34	0.02	1.47	0.13	0.00	0.62	1.16
30	24.96	6.94	8.02	23.26	1.60	4.53	21.64	1.41	0.06	6.45	1.14
Iroquois, New York (IROQ)											
0	0.00	0.00	0.00	0.00	52.29	20.12	27.58	0.00	0.00	0.00	0.00
1	2.28	2.65	0.07	0.00	39.52	22.07	33.16	0.19	0.03	0.00	0.02
30	30.92	5.01	0.46	0.04	11.26	14.09	37.57	0.07	0.44	0.13	0.02
Niagara, Ontario (NIAG)											
0	0.00	0.00	0.00	0.00	0.00	42.18	57.82	0.00	0.00	0.00	0.00
1	5.82	3.54	0.12	0.00	1.32	32.19	56.65	0.16	0.00	0.10	0.11
30	20.35	3.40	0.93	0.07	2.61	14.44	55.92	0.11	0.35	1.55	0.28
Dawn, Ontario (DAWN)											
0	0.00	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00
1	8.06	4.70	0.25	0.02	1.62	5.42	79.54	0.19	0.00	0.09	0.11
30	20.78	3.70	1.11	0.18	2.41	12.08	57.41	0.08	0.34	1.62	0.30
Empress Spot, Alberta (EMPR)											
0	1.88	2.57	12.18	1.75	0.91	0.79	7.55	62.46	0.00	9.93	0.00
1	1.39	1.88	12.00	1.33	1.67	1.44	5.72	62.59	4.51	7.39	0.09
30	16.84	4.26	9.09	5.76	0.18	4.63	26.00	15.30	1.54	15.20	1.23
AECO C Spot, Alberta (AECO)											
0	12.70	5.79	0.23	2.29	4.81	12.06	31.30	6.49	19.08	5.26	0.00
1	11.68	5.40	0.42	1.91	4.79	12.31	30.03	7.27	21.13	4.99	0.06
30	14.68	3.23	9.17	5.64	1.40	4.62	20.30	12.95	13.19	12.81	2.04
Kingsgate, British Columbia (KING)											
0	8.96	8.31	0.88	7.96	1.81	11.41	37.52	0.00	0.00	23.15	0.00
1	8.42	8.55	1.56	9.94	1.45	10.10	35.70	0.09	0.01	24.00	0.18
30	14.25	6.34	6.63	11.76	0.37	5.89	30.37	2.75	0.01	19.91	1.73
Sumas, Washington (SUMA)											
0	6.02	5.43	13.26	11.19	0.30	2.46	10.28	0.02	0.07	14.69	36.27
1	5.07	5.49	15.10	13.47	0.50	1.70	9.29	0.22	0.04	14.77	34.36
30	14.31	5.60	10.21	12.93	0.09	3.74	23.41	3.66	0.12	18.40	7.54

Table C.3. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Iroquois fork with directed edge Niagara to New York.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
Henry Hub, Louisiana (HH)											
0	34.75	3.34	0.00	0.00	47.65	12.78	1.47	0.00	0.00	0.00	0.00
1	36.58	3.53	0.11	1.49	44.43	12.36	1.44	0.01	0.00	0.00	0.06
30	41.21	3.72	1.31	13.16	29.68	9.18	1.12	0.03	0.07	0.02	0.51
Chicago Citygate, Illinois (CH)											
0	0.00	46.61	0.00	0.00	43.36	10.03	0.00	0.00	0.00	0.00	0.00
1	20.17	22.37	3.36	26.49	19.91	7.06	0.23	0.09	0.00	0.00	0.33
30	43.15	4.39	2.14	18.25	22.71	7.71	0.90	0.02	0.12	0.01	0.60
Transco Z6 NY, New York (NY)											
0	14.20	1.37	13.79	0.00	61.19	7.91	1.54	0.00	0.00	0.00	0.00
1	9.18	1.29	9.90	33.07	35.82	5.17	1.02	0.14	0.15	0.05	4.21
30	41.71	3.65	0.97	15.51	27.59	7.78	0.90	0.02	0.24	0.01	1.60
Malin, Oregon (MALI)											
0	14.69	1.41	2.16	12.11	56.59	11.38	1.65	0.00	0.00	0.00	0.00
1	14.73	1.41	1.79	13.43	55.53	11.36	1.58	0.00	0.01	0.00	0.17
30	12.05	1.18	1.99	18.32	53.78	10.78	1.44	0.02	0.01	0.02	0.41
Iroquois, New York (IROQ)											
0	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
1	14.47	3.34	0.70	14.70	62.29	2.78	0.14	0.17	0.14	0.02	1.24
30	38.82	3.39	0.23	2.08	42.74	11.16	1.40	0.01	0.06	0.00	0.13
Niagara, Ontario (NIAG)											
0	0.00	0.00	0.00	0.00	55.73	44.27	0.00	0.00	0.00	0.00	0.00
1	7.53	1.67	2.68	57.10	11.87	13.15	0.01	0.22	0.21	0.12	5.45
30	20.78	1.47	2.60	46.26	14.89	6.75	1.11	0.10	0.56	0.20	5.28
Dawn, Ontario (DAWN)											
0	0.00	0.00	0.00	0.00	41.40	32.89	25.72	0.00	0.00	0.00	0.00
1	9.50	1.83	2.41	41.61	14.85	15.48	10.56	0.16	0.11	0.08	3.41
30	13.38	0.95	3.76	58.53	11.34	4.25	1.07	0.09	0.59	0.22	5.83
Empress Spot, Alberta (EMPR)											
0	5.98	0.49	3.93	34.55	45.89	6.42	0.64	1.89	0.00	0.20	0.00
1	8.19	0.74	2.98	30.08	47.71	7.62	0.73	1.42	0.21	0.13	0.20
30	9.73	1.04	1.98	24.52	50.85	9.46	1.16	0.16	0.09	0.08	0.94
AECO C Spot, Alberta (AECO)											
0	30.96	3.46	6.58	17.06	4.10	3.37	0.01	5.06	28.20	1.20	0.00
1	22.16	2.23	0.78	9.98	45.87	11.10	1.00	0.90	4.94	0.13	0.93
30	11.30	1.22	1.56	21.48	51.61	10.13	1.24	0.10	0.23	0.05	1.08
Kingsgate, British Columbia (KING)											
0	12.76	1.08	2.98	16.66	54.98	9.81	1.43	0.00	0.00	0.30	0.00
1	14.60	1.29	1.79	15.48	54.25	10.72	1.43	0.01	0.02	0.11	0.31
30	12.59	1.25	1.60	19.08	52.80	10.44	1.33	0.03	0.03	0.05	0.80
Sumas, Washington (SUMA)											
0	14.78	1.38	0.85	16.75	51.87	11.18	1.47	0.01	0.06	0.02	1.63
1	14.87	1.38	0.88	16.58	52.01	11.19	1.46	0.01	0.06	0.02	1.54
30	13.64	1.31	1.19	18.00	52.30	10.85	1.39	0.03	0.04	0.03	1.22

Table C.4. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Iroquois fork with directed edge New York to Niagara.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
					Henry Hub, Louisiana (HH)						
0	69.55	3.56	0.00	0.00	21.07	5.07	0.76	0.00	0.00	0.00	0.00
1	70.44	3.80	0.08	0.03	19.58	5.30	0.56	0.10	0.00	0.05	0.05
30	68.52	4.89	0.04	0.12	18.26	6.95	0.49	0.17	0.26	0.11	0.20
					Chicago Citygate, Illinois (CH)						
0	0.00	73.24	0.00	0.00	26.76	0.00	0.00	0.00	0.00	0.00	0.00
1	48.82	33.66	0.08	0.35	11.07	5.16	0.10	0.63	0.03	0.05	0.07
30	69.41	4.74	0.04	0.17	17.42	6.92	0.46	0.07	0.48	0.11	0.19
					Transco Z6 NY, New York (NY)						
0	7.83	0.32	67.05	0.00	24.49	0.08	0.24	0.00	0.00	0.00	0.00
1	21.77	0.27	57.91	0.04	16.14	1.96	0.19	0.53	0.08	0.14	0.98
30	68.47	4.51	2.67	0.06	14.87	6.84	0.67	0.10	1.02	0.17	0.61
					Malin, Oregon (MALI)						
0	52.59	2.79	0.29	22.11	17.48	4.67	0.07	0.00	0.00	0.00	0.00
1	49.89	3.45	1.49	21.48	11.88	5.22	0.07	0.45	0.39	0.98	4.71
30	50.66	7.64	1.94	6.21	12.13	8.37	0.07	2.85	0.13	5.95	4.07
					Iroquois, New York (IROQ)						
0	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
1	17.86	0.00	0.31	0.04	79.40	1.20	0.13	0.62	0.21	0.03	0.20
30	70.28	4.66	0.07	0.03	16.87	6.49	0.55	0.04	0.74	0.19	0.09
					Niagara, Ontario (NIAG)						
0	0.00	1.46	0.00	0.00	25.23	73.31	0.00	0.00	0.00	0.00	0.00
1	46.20	0.87	1.18	0.11	11.95	36.55	0.03	0.99	0.12	0.64	1.36
30	67.84	7.53	0.31	0.02	15.61	2.09	0.16	0.23	2.24	1.53	2.45
					Dawn, Ontario (DAWN)						
0	0.00	0.49	0.00	0.00	8.38	24.34	66.80	0.00	0.00	0.00	0.00
1	54.26	0.80	0.77	0.15	7.59	7.31	26.32	1.04	0.05	0.59	1.10
30	66.96	7.31	0.27	0.06	16.42	1.09	1.34	0.20	2.20	1.55	2.60
					Empress Spot, Alberta (EMPR)						
0	30.64	4.35	8.68	1.51	1.29	1.71	0.51	41.04	0.00	10.27	0.00
1	29.68	3.88	9.33	1.60	1.01	1.55	0.74	40.76	3.05	8.26	0.16
30	34.62	8.83	7.59	2.04	5.22	3.35	0.22	18.83	3.53	11.69	4.08
					AECO C Spot, Alberta (AECO)						
0	8.31	3.42	1.11	0.00	13.19	3.32	1.16	4.76	49.34	15.39	0.00
1	6.01	2.84	1.94	0.09	12.24	2.60	1.33	5.25	53.06	14.23	0.42
30	23.22	7.88	8.04	2.18	3.98	2.72	0.42	12.26	23.06	8.55	7.70
					Kingsgate, British Columbia (KING)						
0	8.38	4.26	0.01	0.67	0.93	1.04	0.10	0.00	0.00	84.62	0.00
1	5.10	3.94	2.64	2.94	0.64	1.36	0.22	1.08	0.93	76.66	4.50
30	24.53	9.83	7.90	4.22	4.17	3.98	0.19	8.71	1.01	24.58	10.88
					Sumas, Washington (SUMA)						
0	4.15	1.51	19.45	4.02	3.12	0.68	0.11	0.39	3.99	7.37	55.22
1	4.50	1.47	19.51	4.56	3.22	0.75	0.23	0.89	4.06	7.69	53.11
30	20.92	7.15	12.81	4.47	2.43	3.35	0.21	7.03	1.43	16.03	24.18

Table C.5. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Niagara fork with directed edge Iroquois to New York.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
					Henry Hub, Louisiana (HH)						
0	53.90	3.62	0.00	0.00	3.70	37.17	1.61	0.00	0.00	0.00	0.00
1	53.97	3.63	0.00	0.00	3.68	37.13	1.59	0.00	0.00	0.00	0.00
30	53.51	3.79	0.00	0.00	3.57	37.53	1.58	0.00	0.00	0.01	0.00
					Chicago Citygate, Illinois (CH)						
0	0.00	92.75	0.00	0.00	0.02	7.24	0.00	0.00	0.00	0.00	0.00
1	55.84	2.34	0.00	0.00	3.73	36.51	1.56	0.00	0.00	0.01	0.00
30	53.67	3.74	0.00	0.00	3.56	37.44	1.57	0.00	0.00	0.02	0.00
					Transco Z6 NY, New York (NY)						
0	62.91	4.23	5.36	0.00	0.65	25.53	1.32	0.00	0.00	0.00	0.00
1	59.18	3.46	1.84	0.00	1.73	32.11	1.67	0.00	0.00	0.00	0.01
30	53.50	3.85	0.01	0.00	3.49	37.52	1.60	0.00	0.01	0.03	0.00
					Malin, Oregon (MALI)						
0	55.43	3.73	0.01	0.18	3.41	35.78	1.47	0.00	0.00	0.00	0.00
1	55.18	3.73	0.00	0.19	3.44	35.99	1.44	0.00	0.00	0.00	0.01
30	52.98	3.97	0.01	0.07	3.48	37.93	1.49	0.00	0.01	0.04	0.03
					Iroquois, New York (IROQ)						
0	0.00	0.00	0.00	0.00	52.29	47.71	0.00	0.00	0.00	0.00	0.00
1	58.67	3.41	0.00	0.00	2.76	33.32	1.78	0.02	0.01	0.03	0.00
30	53.67	3.86	0.00	0.00	3.49	37.36	1.58	0.00	0.01	0.02	0.00
					Niagara, Ontario (NIAG)						
0	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00
1	57.58	3.52	0.00	0.00	4.15	33.12	1.62	0.00	0.00	0.00	0.01
30	53.87	4.27	0.01	0.00	3.85	36.43	1.41	0.01	0.01	0.13	0.01
					Dawn, Ontario (DAWN)						
0	0.00	0.00	0.00	0.00	0.00	67.47	32.54	0.00	0.00	0.00	0.00
1	57.18	3.47	0.00	0.00	4.14	34.04	1.16	0.00	0.00	0.00	0.01
30	53.88	4.25	0.01	0.00	3.87	36.47	1.37	0.01	0.01	0.13	0.01
					Empress Spot, Alberta (EMPR)						
0	52.61	5.20	0.13	0.05	2.81	34.17	0.98	2.16	0.00	1.90	0.00
1	51.75	4.82	0.03	0.02	3.14	36.92	1.27	0.63	0.17	1.24	0.00
30	49.79	5.15	0.00	0.01	3.41	38.61	1.39	0.26	0.07	1.27	0.03
					AECO C Spot, Alberta (AECO)						
0	50.26	4.96	0.03	0.01	3.09	37.54	1.39	0.42	0.53	1.79	0.00
1	50.37	4.91	0.02	0.01	3.12	37.65	1.38	0.38	0.48	1.67	0.00
30	49.71	5.09	0.01	0.01	3.31	38.52	1.42	0.25	0.23	1.44	0.02
					Kingsgate, British Columbia (KING)						
0	58.05	2.29	0.00	0.00	4.00	31.75	1.37	0.00	0.00	2.55	0.00
1	57.96	2.25	0.00	0.02	3.98	31.44	1.44	0.01	0.00	2.88	0.03
30	46.92	5.37	0.14	0.11	3.70	37.44	1.20	0.23	0.01	4.28	0.61
					Sumas, Washington (SUMA)						
0	57.60	3.80	0.79	0.00	2.26	31.48	1.36	0.06	0.08	0.00	2.56
1	57.38	3.74	0.83	0.01	2.28	31.37	1.45	0.04	0.07	0.05	2.78
30	45.75	5.32	1.47	0.22	2.79	33.97	1.17	0.28	0.41	3.18	5.45

Table C.6. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming Niagara fork with directed edge New York to Iroquois.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
					Henry Hub, Louisiana (HH)						
0	87.40	0.06	0.00	0.00	1.34	11.18	0.02	0.00	0.00	0.00	0.00
1	89.13	0.11	0.11	1.27	0.76	5.88	0.91	1.17	0.00	0.59	0.08
30	36.69	1.12	0.07	13.06	0.13	6.57	3.97	11.04	6.83	20.51	0.03
					Chicago Citygate, Illinois (CH)						
0	0.00	67.16	0.00	0.00	0.00	32.84	0.00	0.00	0.00	0.00	0.00
1	0.39	65.31	0.14	0.81	0.00	21.66	0.36	0.96	3.32	7.03	0.02
30	32.58	1.90	0.04	13.66	0.18	7.94	4.19	10.81	8.15	20.54	0.01
					Transco Z6 NY, New York (NY)						
0	0.45	4.48	35.18	0.00	17.47	41.85	0.57	0.00	0.00	0.00	0.00
1	3.63	7.06	30.40	0.72	15.22	39.55	0.54	1.28	0.27	1.25	0.08
30	28.17	1.57	1.01	12.24	0.30	11.43	3.92	11.03	8.76	21.56	0.03
					Malin, Oregon (MALI)						
0	2.83	1.55	6.05	56.08	6.81	26.66	0.02	0.00	0.00	0.00	0.00
1	11.25	0.54	2.27	54.32	3.83	7.99	2.37	4.69	2.12	10.12	0.50
30	21.68	0.16	1.17	46.06	1.97	2.07	3.03	6.36	0.85	15.40	1.25
					Iroquois, New York (IROQ)						
0	0.00	8.53	0.00	0.00	34.07	57.39	0.00	0.00	0.00	0.00	0.00
1	5.62	9.14	0.13	2.51	20.50	52.31	0.80	3.22	1.48	4.27	0.01
30	29.38	1.49	0.10	12.05	0.37	11.60	4.16	11.39	8.68	20.77	0.00
					Niagara, Ontario (NIAG)						
0	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00
1	10.27	1.17	0.23	2.34	0.14	76.36	1.62	3.05	0.67	4.02	0.13
30	22.15	0.77	0.11	11.01	0.36	19.04	6.40	9.99	7.25	22.88	0.04
					Dawn, Ontario (DAWN)						
0	0.00	0.00	0.00	0.00	0.00	70.18	29.82	0.00	0.00	0.00	0.00
1	4.86	0.46	0.04	0.69	0.14	63.60	28.18	0.97	0.07	0.92	0.07
30	22.04	0.72	0.07	11.32	0.44	18.65	6.94	9.65	7.22	22.91	0.05
					Empress Spot, Alberta (EMPR)						
0	9.02	1.66	3.30	9.61	0.45	26.25	5.80	33.71	0.00	10.21	0.00
1	15.66	1.59	0.80	12.87	0.08	17.96	5.20	17.23	7.30	21.30	0.00
30	17.47	1.20	0.45	14.40	0.16	15.43	5.21	15.01	6.22	24.42	0.04
					AECO C Spot, Alberta (AECO)						
0	16.29	1.58	0.43	12.91	0.11	16.32	4.77	14.16	10.05	23.38	0.00
1	16.36	1.58	0.43	13.01	0.11	16.24	4.80	14.08	9.99	23.42	0.00
30	17.08	1.38	0.37	13.75	0.16	15.35	4.90	13.81	8.83	24.37	0.01
					Kingsgate, British Columbia (KING)						
0	7.84	1.47	1.98	18.30	2.95	8.75	3.00	0.00	0.00	55.71	0.00
1	11.84	1.79	0.37	19.65	1.10	13.61	4.70	5.22	2.70	38.89	0.12
30	16.56	0.80	0.13	20.34	0.54	12.44	5.80	11.21	2.52	29.22	0.45
					Sumas, Washington (SUMA)						
0	15.31	1.74	0.38	18.81	0.17	15.26	4.42	8.52	6.05	27.34	2.02
1	14.99	1.77	0.37	18.91	0.15	15.67	4.68	9.23	5.94	26.58	1.71
30	14.31	5.60	10.21	12.93	0.09	3.74	23.41	3.66	0.12	18.40	7.54

Table C.7. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming New York fork with directed edge Iroquois to Niagara.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
					Henry Hub, Louisiana (HH)						
0	61.69	19.88	0.00	0.00	10.96	6.50	0.98	0.00	0.00	0.00	0.00
1	63.05	19.48	0.00	0.02	10.31	6.33	0.76	0.03	0.00	0.00	0.02
30	60.40	21.32	0.04	0.08	9.22	7.87	0.69	0.04	0.26	0.01	0.08
					Chicago Citygate, Illinois (CH)						
0	0.00	100.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	39.91	47.23	0.07	0.23	7.13	5.00	0.16	0.18	0.05	0.00	0.03
30	61.32	20.21	0.09	0.13	9.00	8.00	0.63	0.02	0.51	0.02	0.07
					Transco Z6 NY, New York (NY)						
0	6.38	5.79	64.81	0.00	22.57	0.04	0.41	0.00	0.00	0.00	0.00
1	16.92	3.89	60.37	0.00	15.85	2.01	0.40	0.14	0.04	0.01	0.39
30	59.35	19.71	2.59	0.02	7.45	8.59	0.96	0.03	1.04	0.04	0.23
					Malin, Oregon (MALI)						
0	49.11	14.65	0.26	23.77	7.97	4.20	0.05	0.00	0.00	0.00	0.00
1	49.64	13.05	0.20	24.64	6.11	3.86	0.10	0.10	0.21	0.14	1.95
30	53.55	21.09	0.06	7.22	7.36	6.79	0.13	0.83	0.04	1.13	1.81
					Iroquois, New York (IROQ)						
0	0.00	26.76	0.00	0.00	73.24	0.00	0.00	0.00	0.00	0.00	0.00
1	11.28	23.77	0.00	0.00	62.94	1.32	0.26	0.16	0.20	0.00	0.08
30	60.98	20.91	0.11	0.01	8.14	8.11	0.80	0.01	0.85	0.06	0.03
					Niagara, Ontario (NIAG)						
0	0.00	25.14	0.00	0.00	18.79	56.07	0.00	0.00	0.00	0.00	0.00
1	36.48	14.69	0.05	0.03	11.07	36.74	0.05	0.24	0.06	0.06	0.52
30	72.33	17.27	0.06	0.01	4.58	1.61	0.46	0.05	2.35	0.29	1.01
					Dawn, Ontario (DAWN)						
0	0.00	16.79	0.00	0.00	12.55	37.45	33.22	0.00	0.00	0.00	0.00
1	26.06	10.67	0.00	0.03	8.12	26.69	27.98	0.16	0.01	0.04	0.25
30	70.67	16.49	0.08	0.05	4.74	1.78	2.66	0.04	2.19	0.29	1.02
					Empress Spot, Alberta (EMPR)						
0	9.07	2.78	4.91	1.08	2.91	0.40	1.37	72.86	0.00	4.62	0.00
1	6.93	2.29	3.44	0.73	2.12	1.06	1.98	58.83	19.20	3.10	0.32
30	37.02	22.13	0.35	2.57	5.40	1.44	0.32	13.30	9.50	3.70	4.28
					AECO C Spot, Alberta (AECO)						
0	38.76	12.47	0.01	0.73	5.82	3.46	0.37	0.56	34.54	3.28	0.00
1	35.99	11.87	0.02	0.58	5.74	3.22	0.48	0.63	38.11	3.26	0.10
30	23.25	14.01	0.05	1.78	3.02	1.64	0.44	4.87	43.57	2.37	5.02
					Kingsgate, British Columbia (KING)						
0	29.49	9.36	0.11	10.51	2.87	0.54	0.15	0.00	0.00	46.97	0.00
1	24.74	5.62	0.52	16.51	1.62	0.30	1.45	0.56	1.57	43.10	4.02
30	45.03	18.89	0.17	8.06	3.63	1.31	0.61	4.28	1.07	8.71	8.25
					Sumas, Washington (SUMA)						
0	14.50	0.04	13.03	8.19	2.11	0.11	0.34	0.07	4.61	3.14	53.86
1	13.27	0.08	12.06	9.39	2.47	0.06	0.73	0.33	5.02	3.23	53.36
30	38.92	13.34	3.03	8.27	2.46	1.37	0.58	3.89	1.34	5.82	20.98

Table C.8. Forecast Error Variance Decomposition of 11 Natural Gas Spot Markets. Assuming New York fork with directed edge Niagara to Iroquois.

Horizon	HH	CH	NY	MALI	IROQ	NIAG	DAWN	EMPR	AECO	KING	SUMA
Henry Hub, Louisiana (HH)											
0	46.80	40.41	0.00	0.00	2.69	8.08	2.02	0.00	0.00	0.00	0.00
1	0.68	12.48	9.10	49.81	10.26	14.30	1.48	0.00	0.01	1.88	0.00
30	0.99	12.99	8.85	49.13	10.55	14.36	1.59	0.00	0.01	1.55	0.00
Chicago Citygate, Illinois (CH)											
0	0.00	100.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.89	12.11	9.01	49.30	10.46	14.76	1.58	0.00	0.01	1.88	0.00
30	0.97	12.98	8.87	49.16	10.53	14.36	1.58	0.00	0.01	1.54	0.00
Transco Z6 NY, New York (NY)											
0	0.21	5.00	62.43	0.00	22.71	9.00	0.66	0.00	0.00	0.00	0.00
1	0.84	11.64	6.83	54.37	8.92	14.23	1.67	0.01	0.01	1.49	0.01
30	0.96	13.03	8.89	49.03	10.51	14.40	1.58	0.00	0.01	1.60	0.00
Malin, Oregon (MALI)											
0	0.81	8.44	10.05	55.57	11.61	12.23	1.28	0.00	0.00	0.00	0.00
1	0.81	9.18	9.76	53.87	11.28	12.30	1.29	0.00	0.00	1.50	0.01
30	0.93	13.70	8.79	47.94	10.25	14.71	1.60	0.00	0.01	2.06	0.00
Iroquois, New York (IROQ)											
0	0.00	6.32	0.00	0.00	77.77	15.91	0.00	0.00	0.00	0.00	0.00
1	0.95	13.38	8.69	48.14	11.09	14.60	1.55	0.00	0.01	1.59	0.00
30	0.96	13.03	8.86	49.04	10.52	14.41	1.58	0.00	0.01	1.59	0.00
Niagara, Ontario (NIAG)											
0	0.00	32.32	0.00	0.00	0.00	67.68	0.00	0.00	0.00	0.00	0.00
1	0.76	9.94	9.89	53.01	11.44	11.91	1.51	0.01	0.00	1.52	0.01
30	0.96	13.16	8.80	48.84	10.40	14.57	1.61	0.00	0.01	1.66	0.00
Dawn, Ontario (DAWN)											
0	0.00	19.00	0.00	0.00	0.00	39.78	41.22	0.00	0.00	0.00	0.00
1	0.84	11.79	9.37	50.69	10.90	13.53	1.23	0.00	0.01	1.64	0.00
30	0.96	13.14	8.80	48.88	10.40	14.56	1.61	0.00	0.01	1.65	0.00
Empress Spot, Alberta (EMPR)											
0	0.95	13.11	8.94	48.91	10.48	14.36	1.54	0.03	0.00	1.69	0.00
1	0.93	12.99	8.90	49.12	10.46	14.40	1.58	0.00	0.01	1.60	0.00
30	0.93	12.94	8.89	49.20	10.46	14.39	1.58	0.00	0.02	1.59	0.00
AECO C Spot, Alberta (AECO)											
0	0.93	13.01	8.90	49.10	10.46	14.40	1.58	0.00	0.01	1.61	0.00
1	0.93	13.00	8.90	49.10	10.46	14.40	1.58	0.00	0.01	1.61	0.00
30	0.93	12.99	8.90	49.13	10.46	14.40	1.58	0.00	0.01	1.60	0.00
Kingsgate, British Columbia (KING)											
0	0.97	13.08	8.86	49.01	10.46	14.45	1.60	0.00	0.00	1.58	0.00
1	0.97	13.14	8.85	48.90	10.45	14.47	1.60	0.00	0.00	1.61	0.00
30	0.95	13.41	8.91	48.41	10.43	14.54	1.58	0.00	0.00	1.77	0.00
Sumas, Washington (SUMA)											
0	0.94	13.10	9.01	48.74	10.51	14.46	1.59	0.00	0.01	1.65	0.00
1	0.94	13.15	9.01	48.64	10.50	14.49	1.59	0.00	0.01	1.68	0.00
30	0.94	13.20	8.93	48.72	10.45	14.48	1.58	0.00	0.01	1.69	0.00

VITA

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