

PIPELINE CONSTRAINTS IN WHOLESALE NATURAL GAS MARKETS: EFFECTS
ON REGIONAL PRICING AND MARKET INTEGRATION

by

Roger George Avalos

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Dr. Randal R. Rucker

Approved for the Department of Department of Agricultural Economics and Economics

Dr. Wendy Stock

Approved for The Graduate School

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TABLE OF CONTENTS

1. INTRODUCTION	1
2. BACKGROUND AND LITERATURE REVIEW	5
Background	5
Natural Gas Demand	8
Residential and Commercial Demand	9
Industrial and Electric Power Demand	10
Natural Gas Supply	12
Market Structure	15
Wholesale Markets	16
Local Distribution	20
Contracts	21
Current Natural Gas and Pipeline Capacity Markets	25
3. THEORETICAL MODELS	28
Demand and Supply	28
Residential Demand	28
Commercial Demand	29
Industrial Demand	30
Electric Power Demand	30
Wholesale Demand	31
Wholesale Supply	32
Market Equilibrium and Capacity Constraints	32
Reduced Form Model	33
The Law of One Price	34
4. DATA	36
Data Description and Sources	36
Florida Data Description	38
Southern California Data Description	41
Regional Price Data Description	53
5. EMPIRICAL SPECIFICATIONS	54
Empirical Wholesale Supply and Demand Equations	54
Empirical Reduced Form Model	55
Testing the Law of One Price - Cointegration	57

TABLE OF CONTENTS – CONTINUED

6. EMPIRICAL RESULTS.....	59
Florida - Reduced Form Regressions	59
Florida - Cointegration Tests	64
Southern California - Reduced Form Regressions.....	68
Southern California - Cointegration Tests	75
Cointegration on Regional Prices	79
7. DISCUSSION	82
Conclusions and Implications	82
Suggested Future Research	85
REFERENCES CITED.....	88
APPENDICES	93
APPENDIX A: Abbreviations and Terms	94
APPENDIX B: FERC Rate Setting	97

LIST OF TABLES

Table	Page
2.1 Residential and Commercial Demand Elasticities	11
2.2 Industrial and Electric Own- and Cross-Price Elasticities	13
2.3 Oil and Gas Supply Elasticities.....	15
4.1 List of Data	38
4.2 Florida Summary Statistics.....	39
4.3 Florida Pipeline Capacity Figures	40
4.4 Florida HDD and CDD Percentiles	40
4.5 California Summary Statistics	45
4.6 California Pipeline Statistics	46
4.7 Southern California Pipeline Capacity Figures.....	47
4.8 California HDD and CDD Percentiles	47
4.9 Summary Statistics Regional Prices	53
6.1 FL Reduced Form Regression - Combined Pipelines.....	61
6.2 FL Reduced Form Regression - Individual Pipelines	62
6.3 FL Reduced Form Regression with Interactions.....	63
6.4 FL Cointegration Tests - Non-Binding	66
6.5 FL Cointegration Tests - Binding.....	67
6.6 FL Unit Root Tests	68
6.7 FL Cointegration Tests - Capacity Factors less than 98%.....	69
6.8 CA Reduced Form Regression 95% CF.....	71
6.9 CA Reduced Form Regression Various CF	72
6.10 CA Reduced Form Regression - Individual Pipelines A.....	73
6.11 CA Reduced Form Regression - Individual Pipelines B	74
6.12 California Cointegration Tests - Non-Binding.....	77
6.13 California Cointegration Tests - Binding	78

LIST OF TABLES – CONTINUED

Table	Page
6.14 California Unit Root Tests.....	79
6.15 California Cointegration Tests - Full Sample	80
6.16 ADF Tests on Regional Prices	80
6.17 Cointegration Tests on Regional Prices	81
7.1 Storage Deliverability 2005-2010	86
7.2 Expansions of Major Natural Gas Hubs	87

LIST OF FIGURES

Figure	Page
1.1 Henry Hub & Florida Gas Prices	4
1.2 Henry Hub & Southern California Gas Prices	4
3.1 Market Equilibrium with Capacity Constraints	33
4.1 Florida Gas Transmission System Map	41
4.2 FGT Mt. Vernon Capacity and Flows.....	42
4.3 Gulf South Station 200 Capacity and Flows.....	42
4.4 Gulf South System Map	43
4.5 Hurricane Shut-ins Used in Sample.....	44
4.6 Hurricane Shut-ins 2001-2011	44
4.7 Kern River System Map	48
4.8 Kern Veyo Capacity and Flows.....	49
4.9 Transwestern Capacity and Flows.....	49
4.10 Transwestern System Map	50
4.11 El Paso System Map	51
4.12 El Paso North Capacity and Flows	52
4.13 El Paso TX-NM Capacity and Flows.....	52
5.1 Greater Effect of Demand Shifters with Constraints	57
6.1 Hurricane Shut-ins 2001-2011	75
7.1 Two-Part Tariff in Retail Gas Markets	84

ABSTRACT

Natural gas markets in the United States depend on an extensive network of pipelines to transport gas from production fields to end users. While these pipelines are essential for the operation of natural gas markets, their capacity sets a physical limit on the quantity of gas that can be moved between regions. Taking advantage of a rich data set of daily pipeline capacities and flows, this thesis tests the effects of binding pipeline constraints directly. It is found that these constraints affect the citygate prices for the Florida and Southern California markets. The Law of One Price is tested using cointegration techniques and found to hold when pipeline flows are not constrained, and break down during constrained periods. It is also shown that cointegration techniques may not identify bottlenecks between regions when bottlenecks are not severe, or when they only occur for limited periods of time. Contrary to earlier results, Southern California markets are found to be integrated with the national market. Cointegration tests using data from 14 market points suggest that regional wholesale natural gas markets in the United States are generally integrated into a national market.

INTRODUCTION

Natural gas markets in the United States depend on an extensive network of pipelines to transport gas from production fields to end users. While these pipelines are essential for the operation of natural gas markets, their capacity sets a physical limit on the quantity of gas that can be moved between regions. These capacity constraints have long been recognized as affecting natural gas markets. Breakdowns in market integration and the Law of One Price are often attributed to bottlenecks and binding pipeline capacity in the academic literature. Industry participants also recognize the role of capacity constraints on changing regional basis differentials.¹ Understanding the effects of pipeline capacity constraints is important to market participants and policy makers.

Natural gas markets underwent significant restructuring during the late 1980s and early 1990s. Transportation services were separated from commodity sales and other merchant functions. Where pipeline companies once stood between producers and consumers, open access to transportation services has increased the number of agents that can buy and sell gas between regional markets. A series of papers has studied whether restructuring was followed by increased arbitrage and integration between regional markets. De Vany and Walls (1993, 1996), Serletis and Rangel-Ruiz (2004), and Cuddington and Wang (2006) found that gas markets were well integrated. Later studies by Marmer, Shapiro, and MacAvoy (2007), Murry and Zhu (2008), and Brown and Yücel (2008) found that the links between markets may have weakened over time. There was ample excess capacity in interstate pipelines in the early periods after restructuring. As consumption grew, however, pipeline expansions did not keep pace. This imbalance, the argument goes, has led to bottlenecks and reduced the ability to arbitrage between regional markets.

¹“Pipeline capacity key to gas-price; market stability in Nothereastern US and Canada” Oil & Gas Journal August 28, 2000 and “REX pipeline start affects regional natural gas pricing” Oil & Gas Journal April 2, 2007

No academic paper surveyed here has measured the effect of capacity directly. Breakdowns in market integration are found by identifying breakdowns in the relationship between prices, which are then attributed to binding capacity constraints. Taking advantage of daily data on pipeline capacities and flows, this thesis estimates the effects of binding capacity on regional prices directly. Cointegration techniques are also employed to test for market integration and whether the Law of One Price holds when arbitrage is both constrained and unconstrained.

Florida and Southern California are investigated over the October, 2006 through August, 2011 period. Florida gas markets have faced periodic price spikes, as seen in figure 1. Marmer, Shapiro, and MacAvoy (2007) have identified California as not being integrated with the larger United States market, with pipeline constraints likely between Texas and Southern California, as well as Oregon and Northern California.

On average, binding constraints increased Florida wholesale prices by \$2.50/MMBtu. In Florida, the Law of One Price holds when pipelines do not constrain the flow of gas between markets, but breaks down when flows are constrained. The sample as a whole, including all binding and non-binding periods, is also found to be cointegrated. This suggests that using cointegration to identify pipeline constraints may overlook regions where constraints bind for limited periods of time. Interestingly, it is also found that the cointegrating factors when constraints do not bind are consistent with the structure of natural gas transportation contracts that have a fixed charge per unit shipped and a fuel usage charge as a percent of gas shipped.

The effect of constraints on Southern California prices, while statistically significant, is only \$0.17/MMBtu. Contrary to earlier studies, Southern California prices are found to be cointegrated with Henry Hub prices. There are only a few days where pipeline constraints into Southern California are binding. This suggests that Southern California is integrated with the larger national market.

Cointegration tests are also run on 14 regional price series, comprising 182 price pairs. It is found that all markets pairs are cointegrated. This result supports the view that whole-sale natural gas markets in the United States are generally integrated into a national market. Based on the results for Florida, however, these cointegration tests do not preclude the possibility that bottlenecks may exist for periods of time between these regions. Also, the tests do not speak to markets not included in the sample.

The first chapter of this thesis offers background information and a broad overview of the economics literature pertaining to natural gas markets. The theory, data and empirical strategy employed are presented in the following chapters. Results and conclusions are then offered.

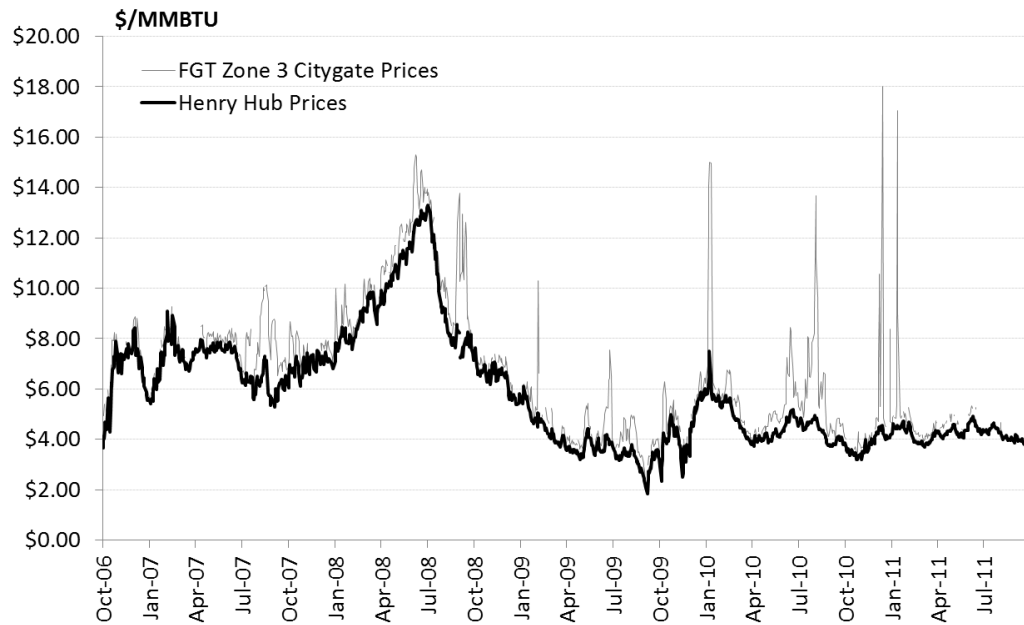


Figure 1.1: Henry Hub and Florida Daily Gas Prices

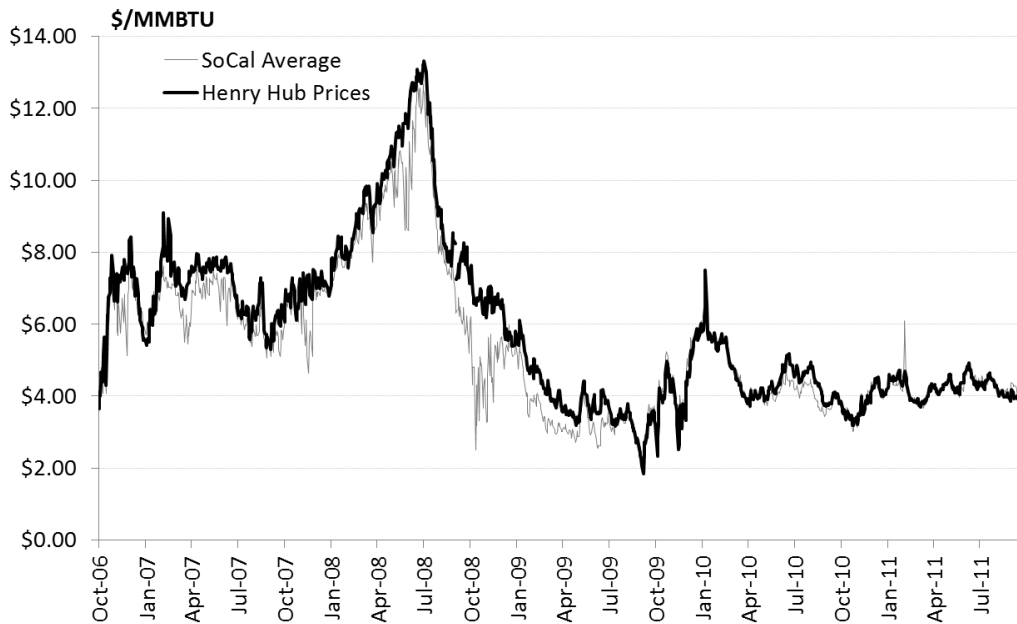


Figure 1.2: Henry Hub and Southern California Daily Gas Prices

BACKGROUND AND LITERATURE REVIEW

Natural gas is an important fuel used for residential and commercial heating, electric generation, and as an input for many industrial processes. U.S. natural gas markets have undergone substantial changes in scope over the past century—from regionally isolated markets to a highly interconnected national market. The market structure has also seen major changes. Until the 1980s, gas markets were regulated from “wellhead to burn-tip.” But by the 1990s, wholesale natural gas markets had been largely restructured and the price controls on field production removed. In response to these changes, contracting arrangements within the industry have evolved. Because of these changes and the growing importance of natural gas as an energy source, there are many economic studies of the industry.

Background

Gas consumed in the United States is mostly produced in the Rockies, Midcontinent, Gulf Coast, Gulf of Mexico, and Western Canada.¹ Because these are removed from major consuming regions in the Northeast, Midwest, Southeast and California, interstate pipelines are required for transportation. Pipeline transportation markets exhibit large economies of scale due to the high fixed costs of construction and obtaining right-of way (Leitzinger and Collette, 2002). This leads to natural monopolies being the least-cost provider of transportation services between production fields and consumers (or other transportation pipelines). The existing structure of natural gas markets in the 1960s and 1970s was one in which production fields and their gathering lines linked to interstate pipelines which then linked to consumers. The interstate pipelines would buy gas from production fields and sell gas to utilities and industrial consumers. This created a situation in which producers would

¹The Midcontinent region includes Texas, Oklahoma, Nebraska, and Arkansas.

have one buyer, the pipeline, and consumers would have one seller, again the pipeline. Because these pipelines were highly specific assets, long-term contracts (twenty or more years in length) were employed to reduce the costs of opportunistic behavior by any of the parties (Dahl and Matson, 1998). Pipelines thus took on the entire range of merchant functions by providing the commodity, transportation, storage, and risk management services. Pipelines would charge a single regulated rate for these bundled services. Pipelines had the ability to aggregate their supplier and customer portfolios. This allowed them to manage the flow and storage of gas to match a more constant flow of production (which minimizes production costs) with highly seasonal and variable demand patterns (Leitzinger and Collette, 2002). This meant that by vertically integrating all these merchant functions, pipelines could take advantage of economies of scope as well (Dahl and Matson, 1998).

Before the advent of welded steel pipelines and long distance transportation networks, gas production fields were generally close to their customers. Throughout the 1800s and into the twentieth century this meant that the costs to build pipelines were relatively small and the number of pipelines allowed for competition in local markets. Contract terms were shorter than they would become in the mid-1900s. In fact, spot markets were quite common (Dahl and Matson, 1998). In the first half of the 1900s, pipelines grew longer, allowing them to reach the southwest gas fields discovered in the 1920s. Natural gas producers and distributors combined into holding companies to bring the gas from producing areas to customers. This internalized many of the transactions and reduced the costs of bringing gas to market. It also led to concerns of market power. The Public Utilities Holding Company Act, which was passed in 1935, split the distribution functions from production and transportation. The Natural Gas Act in 1938 gave regulatory oversight of interstate pipelines to the Federal Power Commission (now the Federal Energy Regulatory Commission or FERC), and forced separate ownership of production and transportation. There was little competition in these early stages of interstate gas markets. Due to the high level of asset

specificity and the possibility of ex post opportunistic behavior, organized spot markets did not emerge Dahl and Matson (1998).

In 1954, the Supreme Court's *Phillips* decision led to the regulation of wellhead prices in production fields. This was done even though it was not clear that any market power was held by gas producers (Dahl and Matson, 1998; MacAvoy, 1962). By the 1970s, FERC controlled entry and exit into transportation markets as well as wellhead prices. At the end of the chain, local distribution companies were regulated by public utility commissions. Natural gas markets were regulated "from wellhead to burn-tip."

The 1970s saw natural gas shortages as FERC price controls formed a ceiling. FERC responded by creating higher price ceilings for "new" gas. With a price ceiling for "old" gas around \$2.00 per Mcf and "new" gas around \$10 per Mcf, producers poured into new gas production. By the 1980s gas production had increased substantially. But with oil prices falling, and industrial demand for gas falling, the regulated prices for gas had become a price floor. Many industrial consumers switched to oil or built their own (shorter) pipelines to natural gas to avoid paying the higher regulated gas prices. The pipelines were not allowed to discriminate between customers by allowing discounted rates to prevent these customers from leaving (Leitzinger and Collette, 2002). Pipeline companies, which had signed contracts forcing them to take-or-pay for gas from producers, faced mounting losses on gas they did not take but paid for anyway. In the face of bankruptcy, many pipeline companies simply refused to honor the take-or-pay provisions in their contracts. Producers sued. But with long periods of time in court with no revenue coming in, many settled (Dahl and Matson, 1998).

In 1983, FERC allowed special marketing programs for producers and consumers to deal directly with one another. In 1985, FERC issued Order 436, allowing the pipelines to declare themselves as open access. This allowed producers and utilities and other large end users to trade gas directly with one another with the pipeline company providing non-

discriminatory transportation services. Most pipelines declared themselves open-access shortly thereafter (Leitzinger and Collette, 2002).

In 1987, Order 500 explicitly separated gas commodity sales and transportation services. Gas marketing companies emerged to take on the transaction costs of matching supplies with consumption (Dahl and Matson, 1998).

Today the natural gas market in the United States is highly integrated, with competitive spot and futures markets. While interstate pipelines are still regulated, a secondary market in transportation rights, where transportation rights can be resold by shippers, helps to provide more efficient pricing of transportation. Gas marketers compete to provide gas to customers and balance supply, storage and consumption. Leitzinger and Collette (2002) point out that, unlike electricity, natural gas restructuring was not planned out ahead of time. Rather, FERC left it to market participants to solve many of the problems for themselves via bilateral contracting after the removal of regulatory barriers. The process that led to the current market structure evolved over more than a decade.

Natural Gas Demand

Natural gas demand is usually divided into residential, commercial, industrial, and electric power sectors. This is due to the fundamental differences in the use of natural gas among these consumers. Residential and Commercial consumers use natural gas primarily for heating. Industrial consumers use gas as an input in their production processes. And gas powered fire plants are used to meet baseload and peak electricity generation requirements. Natural gas consumption is highly seasonal. Residential and Commercial demand increases in colder winter months, whereas power consumption increases in the summer months with the higher demand for electricity.

Residential and Commercial Demand

There are a number of papers that estimate residential and commercial demand. For residential demand, own-price elasticities in the surveyed papers range from a low of -0.09 to a high -1.3, inclusive of short-term and long term price elasticities. Generally, natural gas demand is thought to be inelastic particularly in the short-run. The short-run residential demands range from -0.09 to -0.64. For the commercial sector, short-run elasticities range from -0.042 to -0.83. The long-run range is from -0.4 to -2.258 Dahl (1993). Table 1 shows the estimates of both residential and commercial elasticities from several studies. Note that studies that did not differentiate between short and long-term have their results posted in the “Short Run” column. The majority of these studies are done using state level data for the United States. One study uses individual level data collected from utility bills (Joutz et al., 2008). Another uses data at the county level from California (Garcia-Cerutti, 2000).

The main explanatory variables generally used are prices, heating degree days (HDD), cooling degree days (CDD), and income. Per capita or per customer consumption is the dependent variable in these regressions.

The estimation methods used vary. The most recent estimates, by Davis and Muehlegger (2010), use panel data methods with state, month, year, state by month and state by year fixed effects. They also instrument for natural gas prices using HDD and CDD from other states. They use their elasticities to estimate the welfare effects of local distribution company pricing behavior. Several papers use shrinkage estimators, (Joutz et al., 2008; Maddala et al., 1997). Joutz et al. (2008) also employ panel data methods and add time trends to account for the increasing energy efficiency of housing as new units are built over time. Shrinkage estimators are a compromise between normal panel data methods and estimating each unit of observation (which will be referred to as states hereafter) separately. Panel data assumes that the point estimate is the same across all states. Estimating each

state separately yields different estimates for each state. Shrinkage estimators assume that each state's true point estimate is drawn from the same joint distribution and each estimate is a weighted average of the overall pooled estimate. As Joutz et al. (2008) put it, "each cross-section estimate is shrunk" towards the overall pooled estimate.

Industrial and Electric Power Demand

Industrial demand studies are less numerous. The most recent study of industrial demand is by Huntington (2007). It is quite thorough and has long data coverage (1949-2003). To explain industrial gas consumption, Huntington uses manufacturing output (weighted by gas usage), manufacturing/industrial capacity utilization, HDD/CDD, a dummy variable for price controls, and fuel prices (natural gas, coal, distillate oil, residual fuel oil) in various specifications. Conducting Dickey-Fuller tests, he finds no concern for non-stationarity. The estimations are run using a general autoregressive distributed lag model. Current consumption is a function of lagged consumption and the other current period independent variables.

Urga and Walters (2003) employ dynamic translog and dynamic linear logit models to estimate factor demands in the industrial sector. They estimate cost functions under the two specifications. This is done for oil, coal, natural gas, and electricity factor demands. This is similar to the technique employed by Berndt and Wood (1975). Berndt and Wood only employ the translog specification, and estimate the derived demands for capital, labor, energy and materials (KLEMS) rather than for specific fuels.

Table 2.1: Residential and Commercial Demand Elasticities

Authors	Sector	Years	SR Price	LR Price	SR Income	LR Income
Davis & Muehlegger (2011)	Residential	1989-2007	-0.278			
Joutz et al (2008)	Residential	1992-2007	-0.09	-0.18		
Barnes et al (1982)	Residential		-0.64			
Maddala et al (1997)	Residential	1970-1990	-0.092	-0.239	0.114	-0.491
Maddala et al (1997)	Residential	1970-1990	-0.116	-0.25	0.222	-0.412
Garcia-Cerrutti (2000)	Residential	1983-1997	-0.090			
Garcia-Cerrutti (2000)	Residential	1983-1997	-0.068			
Beierlin et al (1981)	Residential	1967-1977	-0.2317			
Beierlin et al (1981)	Residential	1967-1977	-0.3529			
EIA STEO (2006)	Residential		-0.137			
EIA NEMS (3yr) (2003)	Residential		-0.3	-0.41		
Balestra & Nerlove (1966)	Res/Com	1957-1962		-0.63		0.62
Joskow & Baughman (1976)	Res/Com	1968-1972	-0.15	-1.01	0.08	0.52
Berndt & Watkins (1977)	Res/Com	1959-1974	-0.15	-0.68	0.04	0.133
Davis & Muehlegger (2011)	Commercial	1989-2007	-0.205			
Fuss et al (1977)	Commercial	1960-1971		-0.72		
Griffin (1979)	Commercial	1960-1972	-0.83	-1.6		
Beierlin (1981)	Commercial	1967-1977	-0.161	-1.06	-0.33	-0.219
Beierlin (1981)	Commercial	1967-1977	-0.366	-2.258	0.034	0.21
FEA (1976)	Commercial		-0.38	large	0.73	large
EIA STEO (2006)	Commercial		-0.042			
EIA NEMS (3yr) (2003)	Commercial		-0.29	-0.4		

Serletis, Timilsina, and Vasetsky (2010) employ a locally flexible translog specification. They estimate fuel substitution for all four consumer classes: residential, commercial, industrial, and electric power.

Ko and Dahl (2001) employ the translog cost function to estimate the relationship between fuel prices and fuel choice in U.S. electric generation. Atkinson and Halvorsen (1976) estimate a profit function with the translog specification.

Elasticity estimates are shown in table 2.2. Industrial elasticities range from -0.18 to -0.71 in the short term and -0.24 to -0.67 in the long term. Natural gas demand elasticity estimates in the electric sector range from -0.24 to -1.43.

Natural Gas Supply

Natural gas produced in the United States is divided into several regions and types. The majority of natural gas is produced from conventional resources (15.6 Trillion cubic feet (Tcf) a year in 2009). Unconventional gas is produced from shale (3.1 Tcf) and coal bed methane (1.9 Tcf). Currently the United States is undergoing what has been called a “shale revolution” as shale production has risen by 140% from 2007 to 2009 from 1.3 to 3.1 tcf. Between 2006 and 2008 the estimated total reserves of natural gas saw an unprecedented increase from 1,673 tcf to 1,836 tcf net of production driven by unconventional resources (Potential Gas Committee, 2009). Major supply regions are the Gulf of Mexico, Gulf Coast, Midcontinent, Permian Basin, San Juan Basin, Rockies, Appalachia, and Western Canada.

There are several methods for modeling oil and gas supply including play analysis, discovery process models, econometric models, and hybrids (Walls, 1992). Below is a summary of a survey of these methods by Walls (1992).

Table 2.2: Industrial and Electric Own- and Cross-Price Elasticities

Authors	Sector	Fuel	Years	SR	LR
Huntington (2006)	Industrial	Natural Gas	1949-2003	-0.244	-0.668
Lucas & Muehlegger (2011)	Industrial	Natural Gas	1989-2007	-0.709	
Urga (2003)	Industrial	Natural Gas	1960-1992	-0.2385	-0.2417
Urga (2003)	Industrial	Natural Gas	1960-1992	-0.1792	-0.6578
Serletis et al (2010)	Industrial	Natural Gas	1947-2007	-0.496	
Huntington (2006)	Industrial	Oil	1949-2003	0.121	0.325
Davis & Muehlegger (2011)	Industrial	Oil	1989-2007	0.333	
Urga (2003)	Industrial	Oil	1960-1992	0.2117	0.1575
Urga (2003)	Industrial	Oil	1960-1992	0.0749	0.5020
Serletis et al (2010)	Industrial	Oil	1947-2007	-0.131	
Urga (2003)	Industrial	Coal	1960-1992	-0.0591	-0.0534
Urga (2003)	Industrial	Coal	1960-1992	-0.0339	-0.1243
Serletis et al (2010)	Industrial	Coal	1947-2007	-0.344	
Serletis et al (2010)	Industrial	Electricity	1947-2007	-0.710	
Huntington (2006)	Industrial	Output	1949-2003	0.386	0.916
Berndt & Wood (1975)	Industrial	Energy	1947-1971	-0.47	
Atkinson & Halvorsen (1976)	Electric	Natural Gas	1972	-1.43	
Ko & Dahl (2001)	Electric	Natural Gas	1993	-1.46	
Hudson & Jorgenson (1974)	Electric	Natural Gas		-0.24	
Atkinson & Halvorsen (1976)	Electric	Oil	1972	0.58	
Hudson & Jorgenson (1974)	Electric	Oil		0.20	
Atkinson & Halvorsen (1976)	Electric	Coal	1972	0.45	
Ko & Dahl (2001)	Electric	Coal	1993	1.54	
Hudson & Jorgenson (1974)	Electric	Coal		0.16	

Play analysis is a geologic/engineering method. These models use detailed data on geologic features of a play (a collection of oil or gas prospect fields with common geologic features). Monte Carlo simulation is used to generate a distribution of the number of prospects and the amount of gas in the play. Using an outside price forecast and cost data, each prospect is ranked by present value weighted by its marginal probability of existing. An exploratory well is drilled if the expected value is greater than the costs of drilling.

Discovery process models are also an engineering method. They are generally used in well-developed areas with generous amounts of available data. Instead of geologic data, they employ historical drilling and exploration data to forecast future discoveries. One of the main assumptions typically employed is that the remaining gas to be found declines exponentially with exploratory drilling. Again using outside data on costs and price forecasts, the net present value of wells is estimated to determine how much gas will be produced from the field.

Most econometric models of gas production are based on Fisher (1964) and are used to estimate drilling activity in response to price changes. These studies included: Erickson and Spann (1971), Eyssell (1978), and MacAvoy and Pindyck (1973). Other models are used to estimate the effects on reserve additions directly include Erickson, Millsaps, and Spann (1974), Cox and Wright (1976), and Khazzoom (1971). These estimates are summarized in table 2.3. There are also hybrid models incorporating econometric estimates of model parameters and applying them to engineering models. A recent example of this is Chermak et al. (1999), a hybrid model of a tight sands natural gas formation. The Energy Information Administration also uses a hybrid model in its National Energy Modeling System (NEMS) (EIA, 2010). EIA uses regional data on decline curves, costs, resources, technology, and likelihood of new discoveries.² With these they estimate regional gas supply functions that

²A decline curve is a description of a well's production over time.

Table 2.3: Oil and Gas Supply Elasticities

Authors	Fuel	Drilling	Reserve
Fisher (1964)	Oil	2.45	3.14
Erickson & Spann (1971)	Oil	1.48	0.83
Erickson, Millsaps & Spann (1974)	Oil		1.03
Eyssell (1978)	Oil	1.84	2.43
Pindyck (1974)	Oil	0.07	1.83
Deacon et al (1983)	Oil	1.313	
Griffin & Moroney (1985)	Oil	0.761	
Erickson & Spann (1971)	Gas	0.35	0.69
Pindyck (1974)	Gas	-0.03	2.36

are then used to find regional production when this supply module is incorporated with the larger NEMS model forecast.

Market Structure

Market structure plays a large role in the study of natural gas markets. Standing between production fields and final end users are two industries with large fixed costs and relatively low marginal costs: transportation and local distribution. That is, the average costs of providing services falls with the amount of gas moved. This leads to two industries where a monopoly may provide service at the lowest cost. Both interstate pipeline industries and local distribution companies are regulated. But in the aftermath of natural gas market restructuring, pipelines are now open access. This gave access to transportation services to any gas producer, buyer, or marketer wishing to ship gas. Open access increased the number of buyers and sellers trading natural gas. Several studies have been undertaken to determine if market restructuring has led to competitive interstate wholesale markets. There are also several papers investigating the impact of regulated local distribution companies on end user markets. These studies are discussed in the next two sections.

Wholesale Markets

In many cases interstate natural gas pipelines are natural monopolies and their costs structures are sub-additive. That is, a single provider can deliver at the lowest cost (Gordon, Gunsch, and Pawluk, 2003). The effect of restructuring and open access on the competitiveness of wholesale gas markets has been the focus of much research. The most common method of ascertaining the competitiveness of these markets is to study the degree of integration among the various regional markets. If markets at various locations are integrated into a single competitive market “their prices will be linked and the ‘law of one price’ will hold within the limits of transportation and arbitrage costs” (De Vany and Walls, 1993). Most studies of natural gas market integration thus use cointegration and autoregressive techniques (De Vany and Walls, 1993, 1996; Lien and Root, 1999; Cuddington and Wang, 2006; Murry and Zhu, 2008; Arano and Velikova, 2010). Cointegration techniques allow one to take two non-stationary series of prices and see if they have a linear combination that is stationary. If such a combination exists, then the price series are cointegrated. Under the Law of One Price, regional prices will be related to each other by the costs of transportation and arbitrage. Thus, if the Law of One Price holds between two regions, their prices will be cointegrated. It should be noted that integrated markets imply cointegrated prices, but cointegrated prices do not necessarily imply integrated markets. Findings of cointegrated prices offer support, not definitive proof, of integrated markets. In addition to cointegration techniques, autoregressive models can be used on higher frequency data (such as daily data) to determine the speed with which prices converge to their normal relationship after a shock (Cuddington and Wang, 2006).

These studies find that the U.S. natural gas market has been generally integrated not only among the U.S. regions, but with Canadian regions as well. De Vany and Walls (1993) find that market integration increased during the period of restructuring from 46 percent of

market pairs integrated in 1987 to 66 percent in 1991. In a follow up study (De Vany and Walls, 1996) they find that most markets are integrated. The absence of cointegrated prices between some regions is attributed to a lack of arbitrage paths and constrained capacity. However, they find that the prices generally reverted back to convergence within days. They find that with the exception of Southern California the effects of local market shocks are quickly incorporated by the national market.

In addition to regional integration, prices between upstream and downstream markets should also be integrated. Arano and Velikova (2010) find that residential and citygate prices are integrated in 45 of 50 state markets.

A more recent study on regional price convergence (Murry and Zhu, 2008) finds that, although markets are integrated, there are asymmetric responses at several market hubs. At two hubs, one in the Northeast and one in the Southwest, Murry and Zhu (2008) find after a price increase, the price fall is slower. This favors sellers and may be the result of temporary market power. They find the opposite in a hub in the Rockies and one in Oregon. While Murry and Zhua find empirical evidence for temporary market power in several hubs, they leave the theoretical explanations for future research.

Marmer, Shapiro, and MacAvoy (2007) also find breakdowns in cointegration between market nodes. They speculate that this weakening link between markets is due to pipeline capacity not keeping pace with rising consumption and demands on transportation. Lien and Root (1999) find convergence between NYMEX Henry Hub futures contracts after the futures market experiences shocks. Lien and Root (1999) also find that the longer the time period to maturation, the longer it takes for the shock to converge.

There are potential problems with the use of co-integration techniques for assessing the impacts of restructuring on transaction costs between markets (Kleit, 1998). The first is the possibility of spurious correlation. If a third factor affects both the prices of two markets, it may appear that the two markets have become integrated even though the transactions

costs have not changed. A second problem could be the result of pipeline capacity constraints. Take the example from Kleit and suppose natural gas demand rises in one part of the country. As gas is shipped in from other markets, capacity constraints start to bind. This leads to an increase in transportation rates. While prices rise in all areas (are integrated), the transaction costs have actually increased. Kleit proposes a solution to this problem. He estimates transaction costs directly. His findings are that Louisiana, Texas, and Oklahoma (basically the Gulf Coast and Midcontinent regions) had transaction costs fall dramatically (from 32.5 to 5.5 cents per mmbtu) during the 1984 to 1993 period. This made these regions into one market. The Rockies region, on the other hand, did not experience lower transaction costs. In fact transaction costs may have increased due to pipeline capacity constraints binding as demand for transportation increased with open access.

Another study looks at how pipeline firms changed their behavior after open access (Finnoff, Cramer, and Shaffer, 2004). They find that after FERC order 636 (post open access), pipeline firms have become more similar financially but less similar operationally. Controlling for financial market conditions, they find that firms responded more to financial markets than to regulatory changes. As the authors point out, operational differences occur as pipelines unbundle their services at different times.

Today pipelines have a mix of regulated transport rates (aka tariffs) and market-based rates. Pipelines can change their rates, or put all or part of their capacity up for market based rates. In order to do so, pipeline rate cases traditionally must be litigated before FERC in a rate case hearing. An alternative approach is for the contracting parties to negotiate without a formal hearing (Wang, 2004). Rate case hearings are basically adjustments in contract terms between the parties.

Wang (2004) found that negotiation is much more flexible than the litigation process. Negotiation allows for compromises to be made across multiple contract issues, in the end making all parties better off. An example of this is the inclusion of contract terms

specifying the timing of the next renegotiation. FERC does not have the authority to set the timing of the next rate case. Therefore any litigated rate cases leave the timing of the next case unknown. One party will have to file to open a rate case in the future. An added benefit of negotiated outcomes is that it requires fewer resources from FERC. More contracts can be settled in more timely fashion, with more creative solutions, at a lower cost to the public (Wang, 2004).

Many pipeline transport rates are regulated on a cost-of-service basis. Pipelines are allowed to recover costs plus a rate of return on capital costs in their rates. This type of regulation leads pipelines to try and maximize sales subject to a minimum profit constraint and rate of return constraints (Fanara Jr and Sweet, 2001). This is not conducive to economic efficiency.³ There are, however, market-based rates at which pipeline access can be bought. These market rates are better signals of the value of transportation in the spot market.

With the advent of open access, a secondary market was created for transportation services. If a shipper does not use her contracted capacity, the pipeline can sell it to another shipper in the secondary capacity market.⁴ That is, the pipeline has residual rights on the capacity (Doane et al., 2008). Doane et al. (2008) also show that the Herfindahl-Hirschman Index used by FERC to screen for market power can significantly understate how competitive the market is.

Secondary capacity sales are not the only way market rates come into play. Pipelines may also apply for market-based rates on all or part of their capacity when it is originally released. In effect, the pipeline becomes deregulated (in terms of pricing). Market rates may be granted if FERC determines that the pipeline will not be able to exercise market power as a result (McAfee and Reny, 2007). The current standard used by FERC is that there must be alternative capacity options greater than the peak-day capacity usage of the

³As defined by marginal cost pricing.

⁴The secondary capacity market is also known as the capacity release market

applicant. If this is true, then if the applicant reduced available capacity (by taking portions off the market) in an attempt to raise prices, the alternative pipelines would simply increase their capacity sales by that amount. As a result, prices would not rise. McAfee and Reny (2007) point out that this is too stringent a requirement. If the alternative capacity available is less than the capacity applying for market rates, then the applicant can increase prices by reducing capacity releases. But this does not mean they will. The price increase on the capacity sold needs to more than offset the revenue loss from the capacity held back. Firms will not increase rates if it reduces their profit. McAfee and Reny (2007) estimate that the pipelines would not exercise market power even if the capacity subject to market rates was 2-3 times the excess capacity on alternative pipelines.

There seems to be broad support for the notion that the wholesale gas market is integrated and generally competitive. Pipeline transportation rates are also subject to market pressures in the secondary markets and a number of pipelines charge market based rates.

Local Distribution

At the end of the natural gas transportation networks are local distribution companies (LDCs). LDCs are classic natural monopolies with high fixed costs and low marginal costs. Local markets are thus served by a single regulated investor-owned utility (IOU) or a municipal utility. LDCs earn profits from a rate of return off their capital costs (rate base). LDCs thus have an incentive to increase their rate base to maximize their profits while charging rates above marginal costs. Davis and Muehlegger (2010) find that LDCs in all 50 U.S. states, for each of the 17 years in their sample, charge rates above marginal costs. Using citygate prices as the LDCs marginal cost of gas, they find that residential, commercial and industrial prices are marked up by 47.9 percent, 45.0 percent, and 2.5 percent respectively. Davis and Muehlegger (2010) estimate the annual deadweight loss from this rate of return regulation at \$2.7 billion compared to marginal cost retail pricing. They

suggest that making IOUs into publicly owned entities is probably not wise as financing them through taxes creates its own distortions. Instead, they suggest a “levelized” two-part rate structure with increased monthly fees and setting the retail price for gas equal to the citygate price. In this way LDCs could cover their fixed costs through the monthly fixed charge and the price of gas would be set to the marginal cost of gas.

Many LDCs supply electricity as well as natural gas. Knittel (2003) compares the pricing of dual electric and gas providers to the pricing of single service providers. He finds that dual product firms subsidize industrial consumers through higher mark-ups on residential and commercial customers for electricity and possibly for natural gas. This is consistent with regulated prices responding to the lobbying of interest groups. This cross subsidization is possible due to the monopoly power of the utility in both markets and the more concentrated lobbying power of industrial consumers over residential and commercial consumers. He also draws implications for what cross subsidization of products may have for restructured electricity markets.

Contracts

Natural gas markets have been fertile ground for the study of contracts and transaction costs. Natural gas markets have provided research material to study opportunism, asset specificity, processing of information, and comparative institutional analysis; the four factors that Williamson (1979) identifies as being central to the analysis transaction costs. The bilateral nature of the interactions between production and transportation may tempt one contracting party to opportunistically take advantage of the other. This is particularly true once production wells have been drilled and gas producers have only one purchaser to choose from. Much of the infrastructure in natural gas markets is highly tailored to the needs at hand; pipelines, wells, and gas turbines. As there are few if any alternative uses for

this capital, these investments have a high degree of asset specificity. Many contract provisions act to reduce the costs of obtaining information. As is discussed below, most favored nation clauses are helpful in the absence of price indices. The restructuring of natural gas markets has provided an opportunity to investigate how institutional changes have altered the behavior and operation of market participants. Transaction costs approaches have fared well in explaining natural gas markets. Dahl and Matson (1998) find that participants in natural gas markets have adapted to changing market and regulatory structures in ways that are consistent with transaction cost theory.

One of the most notable changes in natural gas contracts is the reduction in contract lengths of gas sales. This occurred as restructuring reduced the asset specificity caused by the bundled nature of natural gas pipeline services (von Hirschhausen and Neumann, 2008). Post open access, natural gas fields were able to sell gas to any number of gas marketers, instead of only the pipeline. In their review of 311 contracts, von Hirschhausen and Neumann (2008) find that while contract lengths have been falling, the average contract length is greater for investments with higher asset specificity.

Take-or-pay is another non-price contract provision that has been studied (Masten and Crocker, 1985; Broadman and Toman, 1986; Mulherin, 1986). Take-or-pay provisions in natural gas contracts require purchasers (usually pipelines before restructuring) to pay for a specified minimum amount of gas even if the gas is not taken. The claim that take-or-pay provisions are solely an artifact of well head price controls and serve no other economic purpose is rejected by Masten and Crocker (1985). While take-or-pay provisions were more prevalent in price-controlled fields, this is because take-or-pay is a form of non-price competition. The fact that they existed in fields without price controls is strong evidence against the claim that they serve no other economic purpose. Take-or-pay provisions are a way to pre-empt opportunism by the gas purchaser, usually the sole monopsony purchaser of output. There can also be costs imposed by the geophysical attributes of a well when

production is shut-in.⁵ Take-or-pay clauses are also relatively clear in contracts and reduce the costs of interpretation and misunderstandings that could arise from more complex contingency clauses. If market conditions change, the parties will not have to interpret which contingency provisions apply and how (if the contingency was even foreseen). Purchasers simply need to decide whether it is in their interest to keep purchasing gas or pay the minimums. In this way transaction costs are reduced and the gas producer's investment will be secure enough to engage in the contract at the outset. Masten and Crocker (1985) also point out that in the face of changing regulations, if the take-or-pay provisions become burdensome enough, pipelines may efficiently breach their contract. Having a regulator unilaterally void the provisions may be a mistake. This due to the possibility (perhaps likelihood) that the interested parties would renegotiate contract terms with a more efficient outcome. Indeed, this is what eventually took place (Leitzinger and Collette, 2002). Broadman and Toman (1986), and Mulherin (1986) draw conclusions consistent with Masten and Crocker (1985).

Another interesting contract provision is the "most favored nation" (MFN) clause. MFN clauses may state that the price to be paid for gas must be equal to the lowest price charged in a region. This ensures that the buyer benefits from lower prices that the seller might negotiate in the future with other buyers. Conversely, it could require the purchaser to pay the highest price negotiated among all producers within a region (Crocker and Lyon, 1994). Some have argued that MFN clauses are anti-competitive and facilitate collusion (Salop, 1986). Crocker and Lyon (1994) find evidence that is inconsistent with the collusion story. For instance, as the number of "conspirators" grows, it should become more difficult to collude. But as the number of "conspirators" grows, the number of contracts with MFN

⁵There are costs of stopping and starting the flow of gas from a well. Associated gas, from wells that primarily produce oil, may have to be flared as the producer would not want to stop oil production. There is also the possibility of lost gas from wells that share non-unitized reservoirs with other producers.

clauses actually increases. They propose that MFN clauses actually support price flexibility and better track true opportunity costs. The clearest way to see the benefits of MFN clauses is to consider its application to producers. Say a gas producer signs a contract with a MFN clause requiring the purchaser (usually the only monopsony purchaser) to pay them the greater of the contract price or the highest price negotiated with all the other buyers in the region. A gas producer will not sell gas at a loss. As the purchaser shops around to fulfill her gas needs, the lowest cost producers will fill the first quantities (as they can under bid higher cost producers). As the purchaser moves to buy ever higher quantities, they will need to offer a price that the higher-cost producers are willing to accept. For that last amount of gas purchased, the price will have to equal the costs of the marginal producer. Because of the MFN clauses, all the producers will receive this price. This yields prices equal to marginal cost. In the pre-restructured market, natural gas price indices and publications were not as prevalent as they are today. MFN clauses act as a substitute for these price indices and allow producers to obtain information on their regional market price. The idea that MFN clauses are beneficial is supported by Broadman and Toman (1986), Hubbard and Weiner (1991), and Mulherin (1986).

A disagreement on non-price provisions in natural gas contracts is the role of risk allocation. Broadman and Toman (1986) contend that these non-price provisions work to minimize transaction costs and allocate financial risk. Mulherin (1986) on the other hand, contends that the minimization of transaction costs alone explains the existence of these provisions. Regardless of these differences, there is agreement among many that these provisions are generally beneficial to all parties involved, and that allowing renegotiation will allow for better outcomes than regulatory intrusion (Broadman and Toman, 1986; Masten and Crocker, 1985; Mulherin, 1986; Leitzinger and Collette, 2002; Lyon and Hackett, 1993; Crocker and Lyon, 1994). FERC more or less let renegotiation occur during the turmoil of

the 1980s, if not as a matter of conviction, then as a matter of practicality or inability to intervene (Leitzinger and Collette, 2002).

Current Natural Gas and Pipeline Capacity Markets

As noted above, wholesale natural gas markets have been shown to be generally integrated. Bilateral contracts between suppliers and local distribution companies, power producers, or large industrial users, many times with the aid of marketers, make up the trading in the physical gas market. Trading is centralized around hubs. Hubs are physical locations where several pipelines and possibly storage facilities interconnect.

These sectors employ a full range of contracts. Long-term contracts allow firms to have a reliable source of long term supply. Prices are indexed to spot prices, precluding the need for most-favored-nation clauses. Shorter term contracts range from one to 18 months in length. Short-term contracts are standardized, facilitating their trading and re trading on spot markets. The majority of transactions are for delivery over the course of a month or months (Juris, 1998). Spot market trades for monthly gas contracts are usually conducted during the last five business days before the beginning of the month of delivery, known as bid-week. During bid-week the timing and location of deliveries, and transportation services are arranged (Augustine, Broxson, and Peterson, 2006). Gas bought on contracts with durations less than a month is primarily used for balancing purposes. Shippers must inject as much gas into pipelines as they withdraw to maintain balance. Penalties are incurred when more gas is withdrawn than injected (Juris, 1998). For example, during unexpected cold spells when residential and commercial customers increase their heating they draw more gas from the system. The local distribution company must go to the spot market and purchase enough gas to meet their balancing requirements.

There is also a robust financial market in natural gas futures. The NYMEX futures contract for Henry Hub is the most commonly known, but contracts can be traded at many hubs on exchanges or over-the-counter markets. Various financial instruments exist for firms to manage risk; including forward contracts, options, swaps, and regional basis contracts (Juris, 1998).

Transportation services can be purchased on the primary or secondary capacity markets. Shippers (usually gas producers, marketers, local distribution companies, power producers and large industrial consumers) purchase transportation services from pipeline companies. FERC Order 636, given in 1992, required transportation services to be unbundled from gas sales (Leitzinger and Collette, 2002).

In the primary market, the majority of transportation contracts are sold by pipeline companies at FERC-regulated rates. Pipeline companies can sell at market-based rates with FERC approval, if the pipeline is found to have no market power (McAfee and Reny, 2007).

Several main types of transportation services exist with differing rates. *Firm service* is guaranteed access to the contracted capacity for the entire duration of the contract. *Interruptible* service allows the shipper to move a specified volume of gas within a specified time period, but the timing is determined by the pipeline. During peak loads, *firm* service transportation will go through, but *interruptible* service likely will not. *No-notice firm* transportation service gives a shipper leeway in that they do not need to meet daily balancing requirements. That is, they can pull more gas off the pipeline system than they put in for the short term, and not have to replace the gas until later. *Limited firm* transportation is similar to firm transportation, but allows service to be interrupted for a specified amount of time during the contract period (Juris, 1998).

In the secondary transportation market, unused capacity can be resold by shippers or the pipeline company itself if a shipper does not use or resell its contracted capacity. This

is done either through bilateral contracting or auctions. This market is also known as the capacity release market. Capacity released for less than a year is not subject to FERC price caps. During off peak periods, capacity is often released at rates discounted from the original shipper's rate. Transactions in the capacity release market must be reported on the electronic bulletin boards of the relevant pipeline.

An overview of the transportation rate-making process (for non-market based rates) is provided for the interested party in Appendix B. Appendix A contains a list of abbreviations and major regulatory actions in the natural gas market.

THEORETICAL MODELS

Regional natural gas market outcomes are generated by the interaction of supply, demand, and capacity constraints. The method used in this thesis to identify the effects of capacity constraints is straightforward. A reduced-form model with natural gas prices as the dependent variable and demand and supply factors (including a binary variable to indicate when pipeline capacity is binding) as the explanatory variables will be estimated. Estimates of the coefficient for the Binding Capacity variable are significantly different from zero, providing support for the claim that binding capacity affects natural gas prices. Before specifying an empirical model, theoretical models of the natural gas market are discussed.

Demand and Supply

There are four main classes of natural gas consumers: residential, commercial, industrial, and electric power. Residential and commercial customers consume gas primarily for space heating purposes. Industrial gas is consumed as an input either as on-site power generation or as a feedstock. Electric power generators use gas for both peak and base load power generation.

Residential Demand

The residential sector is composed of all private dwellings, including apartments that consume gas as a final good. Residential consumers seek to maximize their utility from gas given available substitutes and their budget constraint. Residential consumers value gas for use in stoves, water heaters, and space heating. Residential demand is derived from a utility maximization over the quantity of gas consumed, q^{res} , and other goods, $\vec{X}$. This is shown

in equation (3.1). Because consumers gain utility from the temperature within their home, the amount of gas required to maintain that temperature changes with weather conditions. A longer term consideration is changes in efficiency as heaters, appliances, and housing materials change. Given these considerations, residential demand should be a function of residential gas prices, prices of other goods, income, weather, and the energy efficiency of the housing stock as shown in equation (3.2).

$$\max_{q^{res}, \vec{X}} U = U(q^{res}, \vec{X}; \text{weather}, \text{efficiency}) \quad (3.1)$$

$$\text{s.t. Income} = P^{res} q^{res} + \vec{X} \vec{P}$$

$$q^{res*} = f(P^{res}, \vec{P}, \text{Income}; \text{weather}, \text{efficiency}) \quad (3.2)$$

Commercial Demand

The commercial sector is composed of non-manufacturing firms and agencies such as hotels, restaurants, wholesale and retail stores, and other service providers. Many government agencies are also included in the commercial sector. Commercial consumers use natural gas as an input in their production process. That is, their demand for gas is a derived demand. Customers at commercial establishments value comfortable environments. As the weather gets colder, commercial consumers must use more gas to maintain indoor temperatures. It is reasonable that the price of substitute heating fuels affects long term gas demand. In the near term, however, heating systems are not changed often and the price of substitute fuels will have little to no effect on gas demand. Generally, an input's demand is affected by the price of other inputs, a classic example being that when the price of capital increases, the demand for labor increases. It seems plausible that the ability to substitute other inputs for heating is very limited. For example, when the wages of a salesman fall, a firm cannot substitute more salesman for spaceheating purposes. These conditions are

shown in equation (3.4). It seems reasonable to expect that commercial gas demand is a function of own-prices, weather, and the efficiency of commercial buildings, as in equation (3.5).

$$\max_{q^{com}, \vec{X}} \Pi = P^y F(q^{com}, \vec{X}; \text{Weather}, \text{Efficiency}) - P^{com} q^{com} - \vec{X} \vec{W} \quad (3.3)$$

$$\frac{\partial^2 F(.)}{\partial X^i \partial q^{com}} = \frac{\partial^2 F(.)}{\partial q^{com} \partial X^i} = 0 \quad (3.4)$$

$$q^{com*} = f(P^{com}, p^y; \text{Weather}, \text{Efficiency}) \quad (3.5)$$

Industrial Demand

The industrial sector is composed of manufacturing, mining, agriculture, forestry, and construction firms. Industrial consumers use natural gas for heat, power, and as a chemical feedstock. Industrial gas demand is also derived from a firm's profit maximization, as shown in equation (3.6). Many industrial users have the ability to switch between natural gas and oil (residual oil or distillate). Many chemical producers can also substitute naphtha for natural gas in their production process. Industrial demand is thus a function of natural gas prices, oil prices, naphtha prices, production technology, and output prices, as in equation (3.7).

$$\max_{q^{ind}, \vec{x}} \Pi = P^{mfg} F(q^{ind}, \vec{x}) - P^{ind} q^{ind} - \vec{X} \vec{W} \quad (3.6)$$

$$q^{com*} = f(P^{ind}, \vec{W}, P^{mfg}) \quad (3.7)$$

Electric Power Demand

Electricity producers use gas-fired power plants as well as coal, oil, nuclear, hydroelectric, and renewable power plants. Power producer's demand for natural gas is also derived from profit maximization, as shown in equation (3.8). Coal and oil are substitutes and their prices affect the demand for natural gas accordingly. Nuclear, hydroelectric, and

renewable sources, while substitutes in production, are not necessarily in price competition in the short run. Once a nuclear power plant is built, its marginal cost of production is always lower than gas or coal. Changes in nuclear power production are usually for operational or maintenance reasons. The marginal costs of hydroelectric power are also very low. Renewable power generation is also detached from price competition with gas-fired generation. Power producers are usually trying to hit a renewable generation target. The timing of much renewable generation can be considered exogenous—dependent on wind and solar activity. It seems reasonable to model nuclear, hydroelectric, and renewable generation as being given, and that the gas, coal, and oil input mix is determined by their prices. Electric power gas demand is thus a function of gas prices, coal prices, oil prices, and power prices. Electric power gas demand is also a function of nuclear, hydroelectric, and renewable electric generation, as in equation (3.9).

$$\max_{q^{pwr}, \vec{X}} \Pi = P^e F(q^{pwr}, X, \text{efficiency}) - P^{ind} q^{ind} - \vec{X} \vec{W} \quad (3.8)$$

$$q^{pwr*} = f(P^{pwr}, \vec{W}, P^e, \text{efficiency, hydro, nuclear, renew}) \quad (3.9)$$

Wholesale Demand

The wholesale demand curve, which is the sum of the demand curves for all of the customer classes, is shown in (3.10). The input prices included in $\tilde{W}$ are P^{coal} and P^{oil} , the prices of other primary fuel inputs in the industrial and electric power sectors.

$$q^{cg*} = f(P^{cg}, P^{coal}, P^{oil}, P^e, P^y, \text{Weather, Efficiency, Hydro, Nuclear, Renew}) \quad (3.10)$$

$$q^{cg*} = \text{wholesale, or citygate, consumption}$$

Wholesale Supply

Many factors affect natural gas production; reserves, labor costs, capital costs, wells drilled in the past, government policy, and hurricanes. It is assumed that the law of one price generally holds in natural gas markets.¹ It is also assumed that the Henry Hub price incorporates all known and relevant information and expectations. As the price in a region increases relative to Henry Hub (increasing basis differential) more gas will be shipped to that region. The supply of gas to a region will be a function of Henry Hub prices (P^{hh}) and the citygate prices (P^{cg}) in that region up until the capacity constraint q^c . (3.11)

Market Equilibrium and Capacity Constraints

The wholesale market will be in equilibrium when the quantity of gas supplied equals the quantity demanded. Figure 3.1 shows the effects of capacity constraints on a gas importing region. In the absence of binding capacity constraints, say in low demand months where demand is something like D^0 , the intersection of supply and demand determines quantity and price. In this case Q^0 and P^0 . In high demand periods, represented by D^1 , if there were no capacity constraints the equilibrium quantity and price would be Q^1 and P^1 . Because the pipeline capacity is full at Q^c , there can be no supply response beyond Q^c . The supply curve becomes vertical. The quantity of gas supplied will be Q^c . The wholesale price must rise to P^c so that the quantity demanded also equals Q^c . The shaded area represents the deadweight loss from gas that would have been traded in the absence of capacity constraints.

¹This assumption is tested in Chapter 6.

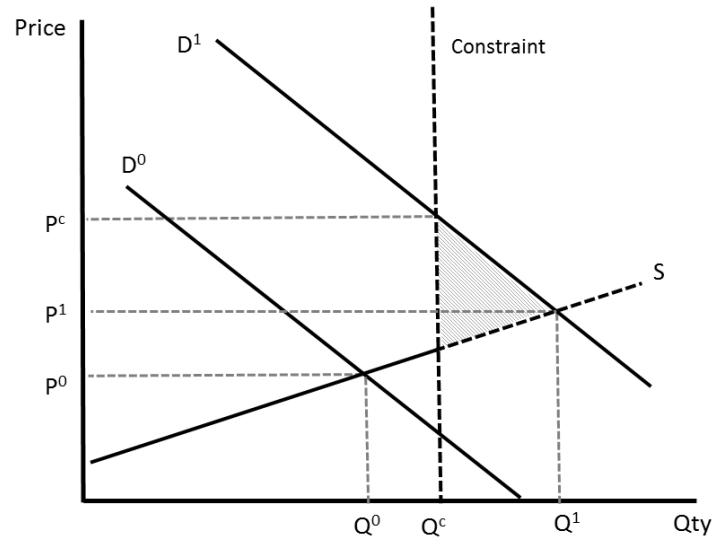


Figure 3.1: Wholesale Market Equilibrium with Capacity Constraints - Importing Region

Reduced Form Model

A structural model of supply and demand does not need to be estimated to test whether or not capacity constraints have had an impact on past market outcomes. A reduced form model can be used to estimate the effect of supply and demand shifters, as well as capacity constraints, on equilibrium prices. Equilibrium citygate prices (wholesale prices) are a function of Henry Hub prices, commercial output prices, electricity prices, oil prices, industrial output prices, weather, efficiency, and hydroelectric, nuclear, renewable generation and the capacity constraint.

$$P^{cg*}(P^{hh}, P^y, P^e, P^{coal}, P^{oil}, P^{mfg}, \text{weather}, \text{efficiency}, \text{hydro}, \text{nuclear}, \text{renew}, q^c) \quad (3.12)$$

Equation (3.12) is the basis for the empirical specification developed in Chapter 5.

The Law of One Price

In integrated and competitive markets, price differences will be arbitrated away. If there were no transportation or arbitrage costs, prices in different regional markets would converge to a single price. The inclusion of these costs means that the difference between prices in region A and region B will be less than or equal to the costs of transportation and arbitrage (the transaction costs costs in Equation (3.14)).

$$|P^A - P^B| \leq \text{Transaction Costs} \quad (3.13)$$

Pippenger and Phillips (2008) show how four pitfalls can cause statistical tests to reject the Law of One Price when it actually holds. These pitfalls are: the goods in two markets are not identical; resale or arbitrage is restricted; the time for transporting the goods is not accounted for; or there is no account of transportation costs.

Natural gas is a homogeneous good, methane. Gas in one region is identical to gas in another. Market restructuring and open access have increased the number of agents able to arbitrage between markets. Natural gas can be traded relatively quickly. When gas is “moved” from one location to another, the agent pulls gas off at the destination and puts gas in at the source so as to maintain system balance. This means that the amount of time it takes to trade gas can be less than the time it takes to physically move the gas. The structure of transportation costs can be accounted for in a regression and pipeline tariff filings are public information.² All these make natural gas markets well suited for testing the Law of One Price.

²The β_0 and β_1 in a bivariate regression on prices can account for the transportation costs.

If natural gas moves from producing areas to consuming areas, as is the case in Florida, markets can be either upstream or downstream from one another.³ The price in downstream markets should be equal to the price in upstream markets plus the transportation and arbitrage costs of moving the good to the downstream market.

Natural gas pipeline transportation rates are split into two general parts: fixed costs (per MMBtu) and variable/fuel costs (a percent of MMBtus shipped). This is because a portion of the gas shipped is used to operate the pipeline. The buyer of the transportation service pays the fuel cost by providing this gas to the pipeline. Transportation costs thus vary with the price of natural gas. Equation (3.14) shows how upstream and downstream prices will be related if the law of one price holds.

$$P^{\text{downstream}} = \text{Transport/Transaction costs} + 1/(1 - \text{Fuel Cost \%})P^{\text{upstream}} \quad (3.14)$$

As an example, Florida Gas Transmission (FGT) has variable rate for transport services moving gas from FGT Zones west of Florida into the Florida market area (FGT Zone 3) is 3.1 percent of the gas transported. Shippers wanting to move 1.00 MMBtus into Florida would need to supply 1.032 MMBtus $(= (1 \text{ MMBtu}) / (1 - 0.031))$ to the pipeline. Because natural gas is an input into natural gas transportation services, as the price of gas increases, so does the cost of transporting the gas. If the Law of One Price holds, then an increase at Henry Hub of 1.0 dollars, should cause the price at FGT Zone 3 to rise by 1.032 dollars to account for the increased cost of transportation.⁴

³It is meant that one regional market is upstream or downstream of another, i.e. not in the sense that the refining market is upstream of the retail gasoline market.

⁴Assuming there are no other transaction costs that vary with the price at Henry Hub.

DATA

Data Description and Sources

Table 4.1 lists the data used in this study. Data on daily pipeline capacities and flows used in the empirical analysis presented below were provided by Lippman Consulting Inc. (LCI), a major supplier of natural gas data in the industry.¹ LCI collects data at receipt and delivery points, as well as at various compressor stations, for most interstate pipelines in the United States and Canada. These data, as well as LCI data on gas production, consumption, and imports/exports are used for a variety of purposes by energy traders, utilities, power producers, production companies, pipeline companies, consulting firms, research organizations and the U.S. Department of Energy's Energy Information Administration (EIA). Pipeline capacity and flow data for state border crossings available from the EIA is annual and available only through 2008.² With the LCI data, capacity constraints can be identified for specific days at specific points along a pipeline. This is critical as capacity along the length of a pipeline may not be full, but a particular point may be a bottleneck.

Daily temperature data from the National Oceanic and Atmospheric Administration are collected and stored in a database by Professor Joseph Atwood at Montana State University.³ From these data, daily heating and cooling degrees days are calculated for each weather station and averaged across various regions within the United States. A heating degree day is 65 degrees less the average temperature for that day. For example, if the average temperature is 60 degrees, the HDD would be five. For all temperatures above 65 degrees, HDD is zero. For CDD, 65 degrees is subtracted from the actual temperature and all temperatures below 65 degrees have CDD equal to zero.

¹www.lippmanconsulting.com

²As of 10/28/2011 http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/usage.html

³Department of Agricultural Economics and Economics

Daily gas prices were purchased from Natural Gas Intelligence (NGI) for 14 hubs and market points in the United States.⁴ These are the same data found in NGI's Gas Daily Price Index.

Daily West Texas Intermediate (WTI) oil prices were downloaded from EIA.⁵ Oil prices are converted to dollars per MMBtu using a factor of 5.6 MMBtu per barrel.⁶

Coal prices are constructed from EIA Form 923 Schedule 2 data on utility and non-utility generator fuel purchases. Coal prices are reported in \$/MMBtu. All prices are converted to real 2011 dollars using the Producer Price Index (excluding energy) available from the Bureau of Labor Statistics (BLS). Total state personal income were obtained from the Bureau of Economic Analysis and rescaled from millions to billions of dollars.

Data for coal prices, industrial output price indices, and producer price indices are only available at monthly intervals. These data are put into daily form by making each day in a month the monthly value.⁷ Price indices are from the Bureau of Labor Statistics.

Hurricanes are an annual threat to natural gas production in the Gulf of Mexico and along the Gulf Coast. The Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service) releases weekly data on the level of production shut-ins (in MMCFD) due to hurricanes. Linear interpolation is used to fill in the days between reports.

⁴<http://intelligencepress.com/>

⁵http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm

⁶Conversion factor from EIA http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator_basics

⁷Linear interpolation was also tested, but did not affect the results.

Table 4.1: List of Data

Data	Units	Source	Frequency
Pipeline Capacities	MMCFD	LCI Inc.	Daily
Pipeline Flows	MMCFD	LCI Inc.	Daily
Natural Gas Prices	\$/MMBtu	NGI Gas Daily	daily
WTI Oil Prices	\$/BBL	EIA/Thompson Reuters	Daily
Coal Prices	\$/MMbtu	EIA	Monthly
Heating Degree Days	HDD	MSU-NOAA	Daily
Cooling Degree Days	CDD	MSU-NOAA	Daily
Industrial Output Prices	Index	BLS	Monthly
Industrial Output	Index	Federal Reserve	Monthly
Producer Price Index	Index	BLS	Monthly
Personal Income	Billion \$	BEA	Monthly
Hurricane Shut-ins	MMCFD	MMS	Varies

Florida Data Description

Florida is served by two interstate pipelines, Florida Gas Transmission Company (FGT) and Gulf South Pipeline Company (Gulf South). There are no interstate pipelines exporting gas from Florida. The state has very little natural gas production, accounting for less than 1 percent of in-state consumption. There are also no storage or liquefied natural gas import facilities in the state. Gas consumption is dominated by the power sector, which accounts for over 80 percent of all consumption. The industrial sector consumes nearly 9 percent while residential and commercial sectors combine for about 8 percent. The small size of residential and commercial consumption relative to the power sector is due to low heating requirements (see average HDD in 4.2). Cooling requirements are higher (see average CDD) and are a key electric demand driver.

Table 4.2 shows summary statistics for the daily Florida data. The sample covers October 1, 2006 to August 29, 2011, with some periods of unavailable data. Daily hurricane production shut-ins are also included in Table 4.2. Figures 4.1 and 4.4 show the pipeline

Table 4.2: Florida Summary Statistics - Oct. 1, 2006 through Aug. 29, 2011

Variable	Units	Mean	Std. Dev.	Min.	Max.	N
FGT Z3 Citygate	\$/MMBTU	6.75	2.63	2.26	18.00	999
Henry Hub Price	\$/MMBTU	5.87	2.29	2.06	13.31	999
WTI Price	\$/MMBTU	13.8	3.70	5.72	25.05	999
Coal Price	\$/MMBTU	3.14	0.36	2.53	3.73	999
Total Personal Income	Billion \$	12.74	0.313	12.24	13.317	999
Industrial Price	Index	96.4	5.6	88.4	109.1	999
Heating Degree Days	HDD	2.43	4.76	0	27.57	999
Cooling Degree Days	CDD	9.57	6.81	0	22.31	999
Total Import Flows	MMCFD	2,666	618	540	4,380	999
Total Import Capacity	MMCFD	3,393	482	1,114	4,380	999
Total Import Capacity Factor	%	78.65	13.69	46.47	107.26	999
Hurricane Shut-ins	BCFD	0.21	0.87	0	7.06	999
Industrial Production	Index	184.2	11.8	165.4	209.5	999

maps for the Florida Gas Transmission and Gulfstream pipeline systems from Lippman Consulting. Mt. Vernon, near the border of Mississippi and Alabama (labeled 2950) is a point where capacity often binds on FGT. A similar point on Gulfstream is Station 200, the black dot off the Florida Coast (labeled 1330). The daily capacity and flow data for these two points can be seen in Figures 4.2 and 4.3.

Figure 4.5 shows hurricane shut-ins over the sample period. The largest hurricanes are Gustav and Ike in 2008. Figure 6.1 shows the hurricane shut-ins over the 2001 to 2011 period for reference. These are the same shut-in data used for Southern California.

Table 4.3: Florida Pipeline Capacity Figures

	Mt.Vernon	Gulf St.200	Total Import
Days at Capacity Factors			
Capacity Factor	Days	Days	Days
100 %	27	42	16
>99 %	58	156	64
>98 %	72	209	89
>97 %	88	259	119
>96 %	108	310	166
>95 %	142	359	205
>90 %	303	1,490	375
Pipeline Capacities			
As Of	MMCFD	MMCFD	MMCFD
10/1/06	2,250	1,114	3,364
1/7/09	2,250	1,118	3,368
1/12/2009	2,250	1,253	3,503
4/4/2011	2,950	1,253	4,203
7/2/2011	3,050	1,253	4,303

Table 4.4: Florida HDD and CDD Percentiles

Percentile	HDD	CDD
Min	0.00	0.00
10 %	0.00	0.33
25 %	0.00	2.79
50 %	0.05	8.12
75 %	2.64	15.89
90 %	8.53	18.13
95 %	12.28	19.09
99 %	20.93	20.41
Max	28.82	22.31

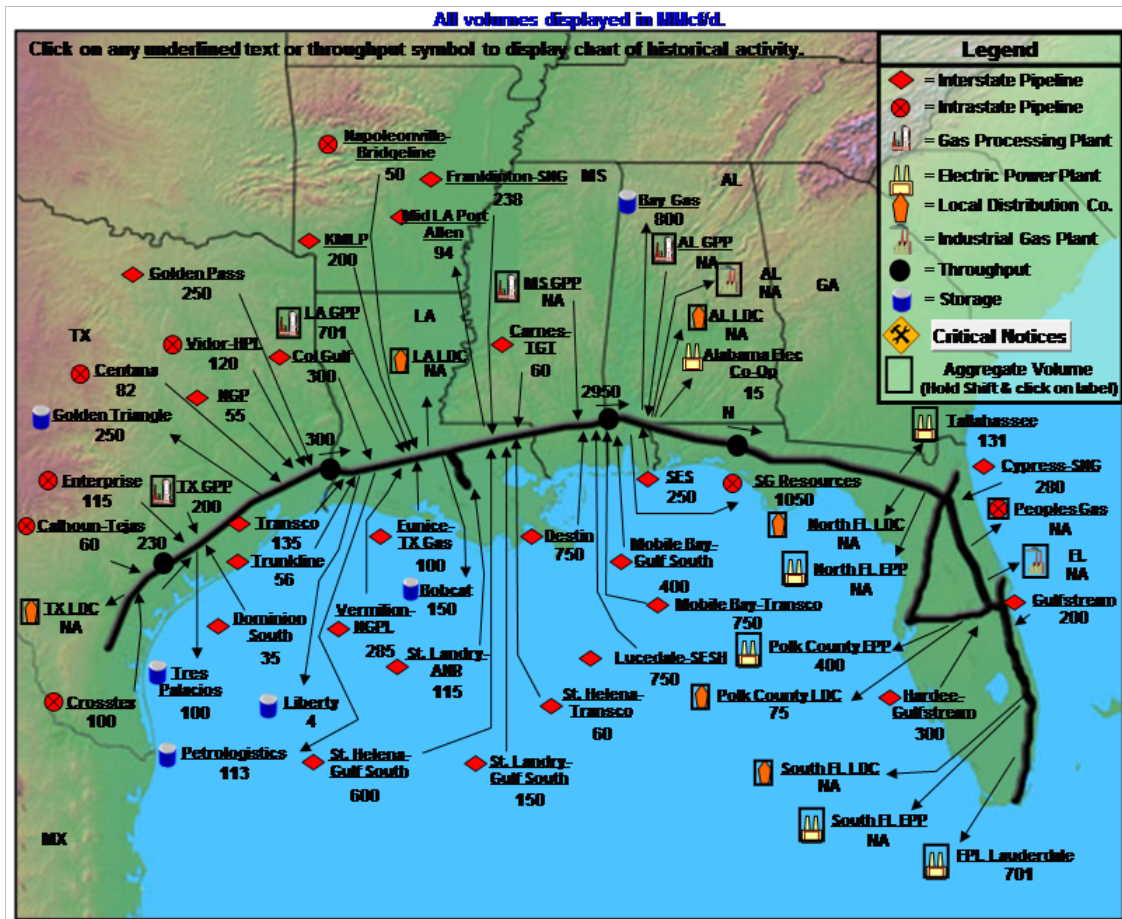


Figure 4.1: Florida Gas Transmission System Map from LCI Inc.

Southern California Data Description

Southern California is served by three major interstate pipeline systems; Kern River, El Paso, and Transwestern. Pacific Gas and Electric company has a pipeline that ships gas from Southern to Northern California. Unlike Florida, California has several storage facilities. Peak delivery capabilities from these storage facilities by 15.2 percent from 2006 to 2010, from 6,460 to 7,445 MMCFD.⁸ Unlike Florida, some natural gas flowing into Southern California flows out of the region into Northern California. Due to these

⁸<http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f,eport=RP7>

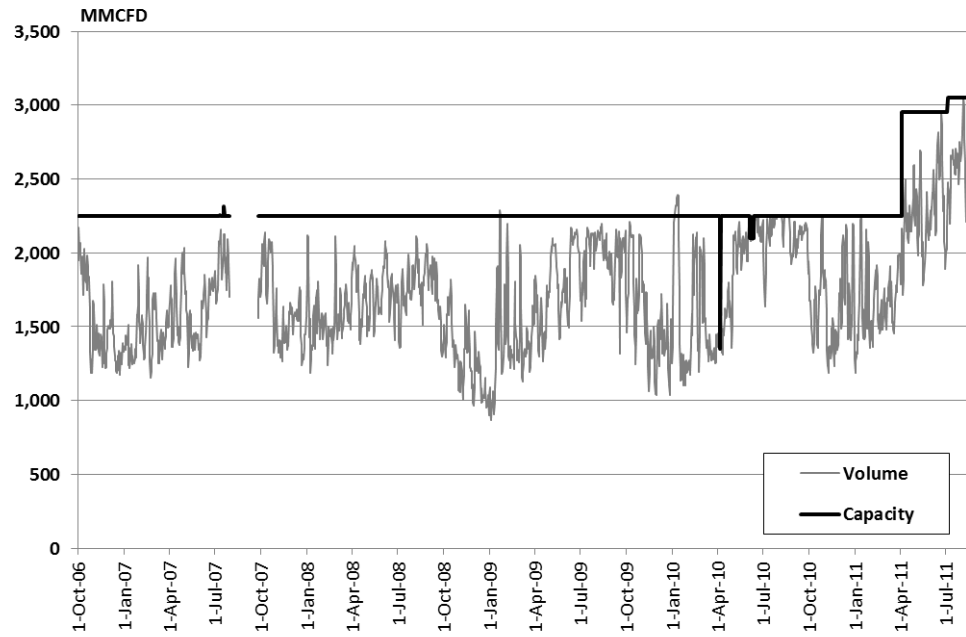


Figure 4.2: FGT Mt. Vernon Throughput Capacity and Flows

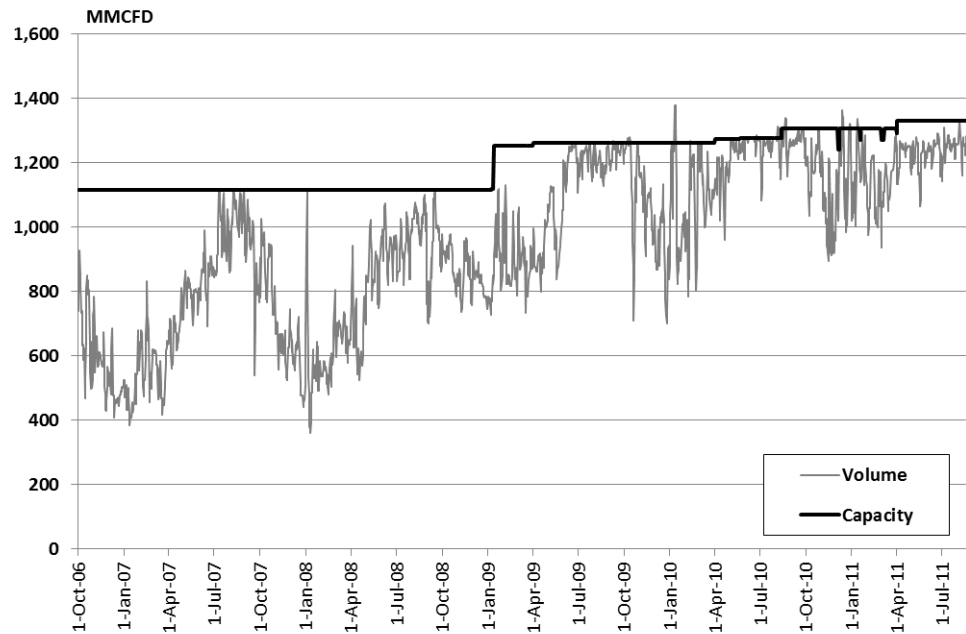


Figure 4.3: Gulf South Station 200 Throughput Capacity and Flows

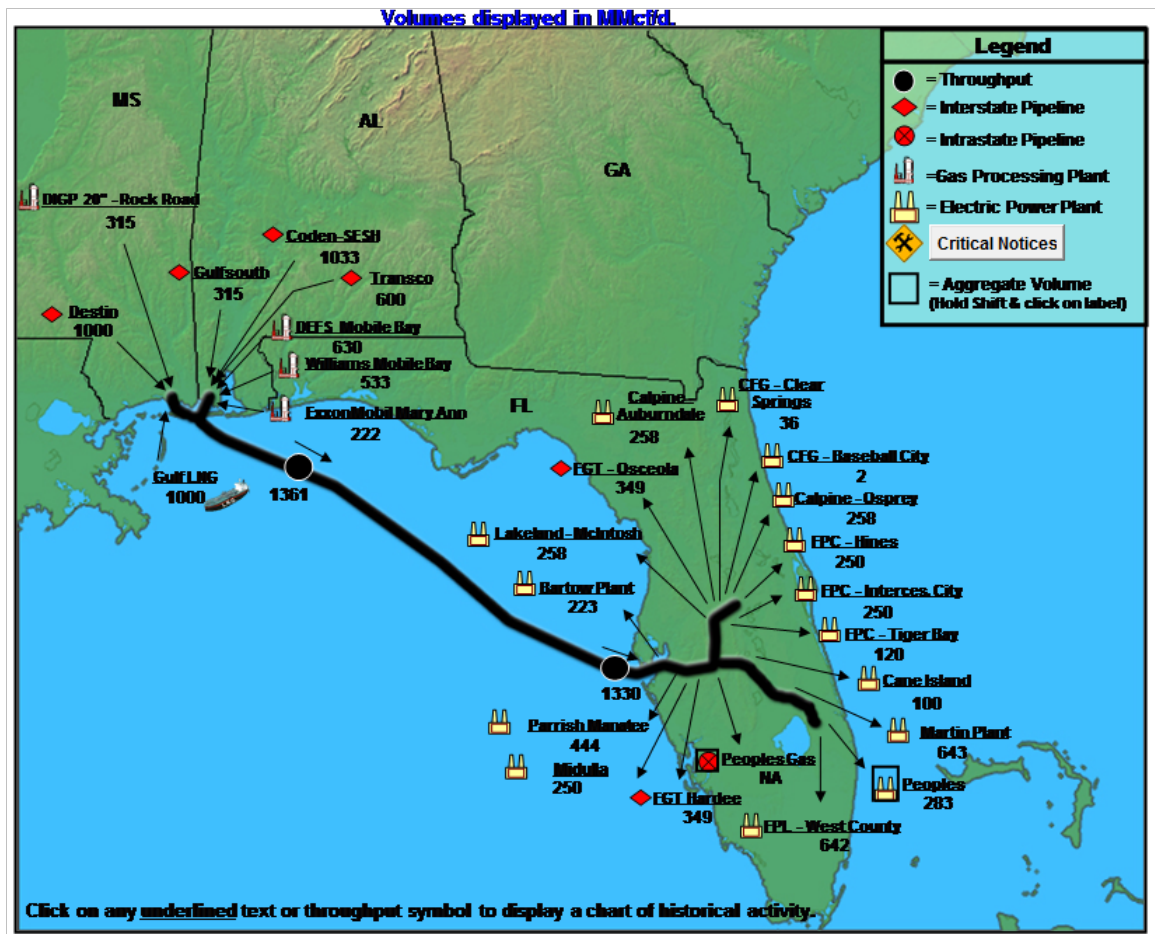


Figure 4.4: Gulf South System Map from LCI Inc.

complications Southern California is not as “clean” a region for estimating the effects of capacity constraints.

The state has significant natural gas production, accounting for 32.5 percent of in-state consumption (in 2009).⁹ In 2009, 21.3 percent of natural gas consumption was in the residential sector, 11.0 percent in the commercial sector, 31.3 percent in the industrial sector, and 35.8 percent in the electric power sector.

Table 4.5 shows summary statistics for the daily Southern California data. The sample covers October 1, 2006 through August 29, 2011, with some periods of unavailable data.

⁹2009 is the most recent year for which annual data is available <http://www.eia.gov/naturalgas/data.cfm>

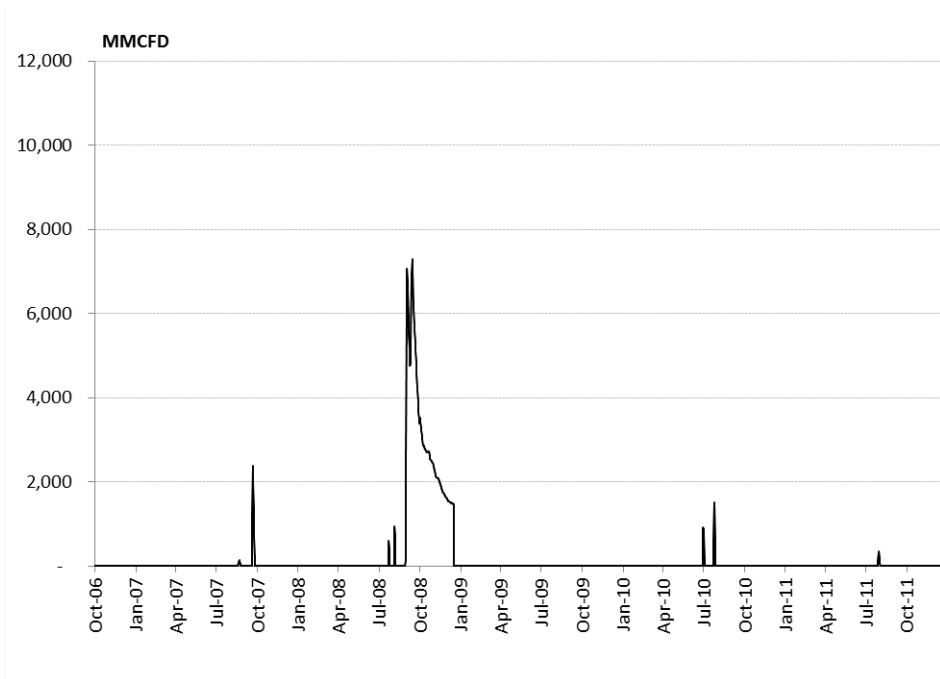


Figure 4.5: Hurricane Shut-ins Used in Sample

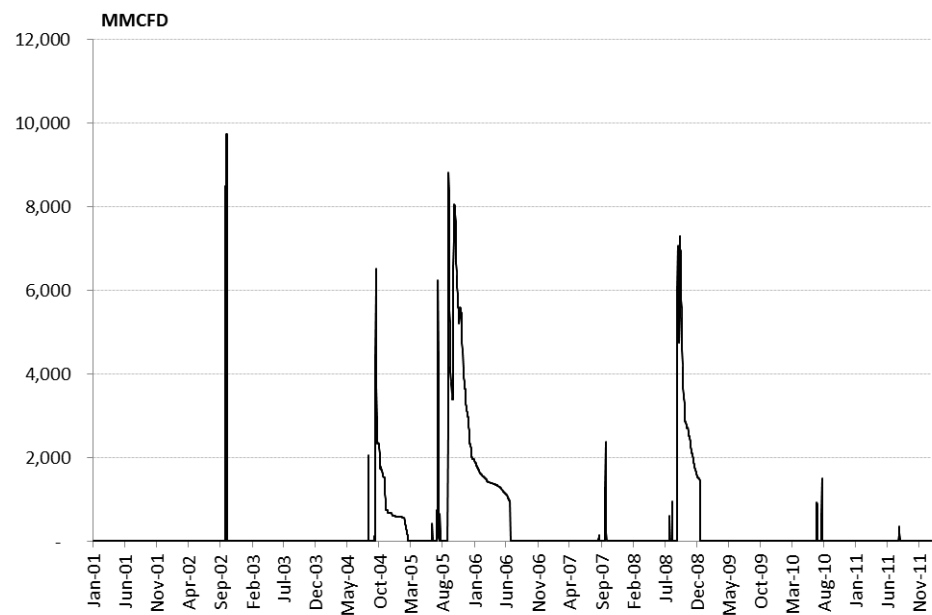


Figure 4.6: Hurricane Shut-ins 2001-2011

Table 4.5: California Summary Statistics

Variable	Mean	Std. Dev.	Min.	Max.	N
SoCal Price	5.39	2.06	2.22	12.68	1164
Henry Hub Price	5.79	2.27	1.84	13.31	1164
WTI Price	80.89	21.64	30.28	145.31	1164
Coal Price	1.39	0.16	1.13	1.86	1164
Monthly Personal Income	12.28	0.38	11.64	13.03	1164
Industrial Price	0.935	0.093	0.789	1.117	1164
Heating Degree Days	8.57	7.34	0.12	30.03	1164
Cooling Degree Days	3.27	4.08	0	16.47	1164
Total Import Flows	4,597.63	444.27	3289.70	5677.76	1164
Total Import Capacity	5,672.50	132.24	4,515	5,851	1164
Total Import Cap Factor	0.811	0.079	0.563	1.004	1164

Figures 4.7, 4.11 and 4.10 show the pipeline maps for the Kern River, El Paso, and Transwestern pipeline systems. The Veyo compressor station, the black dot in the southwest corner of Utah (labeled 2194), is a point where capacity often binds along the Kern River pipeline. Potential bottlenecks on the El Paso system are in bringing gas west along the North system in Arizona, and bringing gas west from Texas into New Mexico. Along the Transwestern system, bringing gas west through Arizona is also a potential bottleneck. The daily capacity and flow data for these points can be seen in Figures 4.8, 4.12, 4.13 and 4.9. The fluctuating capacity is largely due to temperature changes affecting the amount of gas that can flow through above ground pipelines. Capacity factors are the percent of available capacity that is used. The falling flows along El Paso North are likely due to falling production in the mature San Juan Basin fields.

Table 4.6: California Pipeline Statistics

Variable	Mean	Std. Dev.	Min.	Max.	N
Kern River Veyo Flows	2,023.82	114.96	1,395.29	2,282.92	1,164
El Paso North Flows	1,922.53	272.093	1,015.00	2,340.24	1,164
El Paso TX-NM Flows	1,606.04	296.40	533.88	2,395.90	1,164
Transwestern West Flows	1,069.06	169.21	328.59	1,253.62	1,164
Kern River Veyo Capacity	2,086.65	85.61	1,814.0	2,288.5	1,164
El Paso North Capacity	2,172.497	132.24	1,015.0	2,351.0	1,164
El Paso TX-NM Capacity	2,200.0	0.0	2,200.0	2,200.0	1,164
Transwestern West Capacity	1,300.0	0	1,300.0	1,300.0	1,164
Kern River Veyo Cap Factor	97.1	5.2	62.8	101.2	1,164
El Paso North Cap Factor	88.6	12.2	53.9	100.0	1,164
El Paso TX-NM Cap Factor	73.0	13.5	24.3	108.9	1,164
Transwestern West Cap Factor	82.2	13.0	25.3	0.964	1,164
Storage PG&E Flows	1.752	3,36.08	-1,438	536	1,164
Storage Wild Goose Flows	7.57	168.55	-679.85	317	1,164
Storage Lodi Flows	-30.021	189.67	-709.0	471.0	1,164
Storage Central Valley Flows	8.68	6.74	0.5	20	11
Storage Gill Flows	28.04	56.80	-96.99	217.52	228
Total Storage Flows	-15.13	578.59	-2,234.0	1,095.0	1,164

Table 4.7: Southern California Pipeline Capacity Figures

	Kern River Veyo	El Paso North	El Paso TX-NM	Transwestern West	Total Cap SoCal
Days at Capacity Factors					
Cap Fac	Days	Days	Days	Days	Days
100%	208	328	15	0	1
>99%	622	417	21	0	2
>98%	766	465	27	0	4
>97%	873	504	32	0	11
>96%	944	540	42	3	21
>95%	1,007	581	49	25	32
>90%	1,154	739	107	420	157
Pipeline Capacities					
As Of	MMCFD	MMCFD	MMCFD	MMCFD	MMCFD
10/1/06	2,042	2,190	2,200	1300	7,732
4/9/10	2,197	2,190	2,200	1300	7,887

Table 4.8: California HDD and CDD Percentiles

Percentile	HDD	CDD
Min	0.12	0.00
10%	0.66	0.00
25%	1.66	0.03
50%	7.39	0.82
75%	14.66	6.03
90%	19.72	9.86
95%	22.34	11.22
99%	26.01	14.61
Max	32.62	16.47

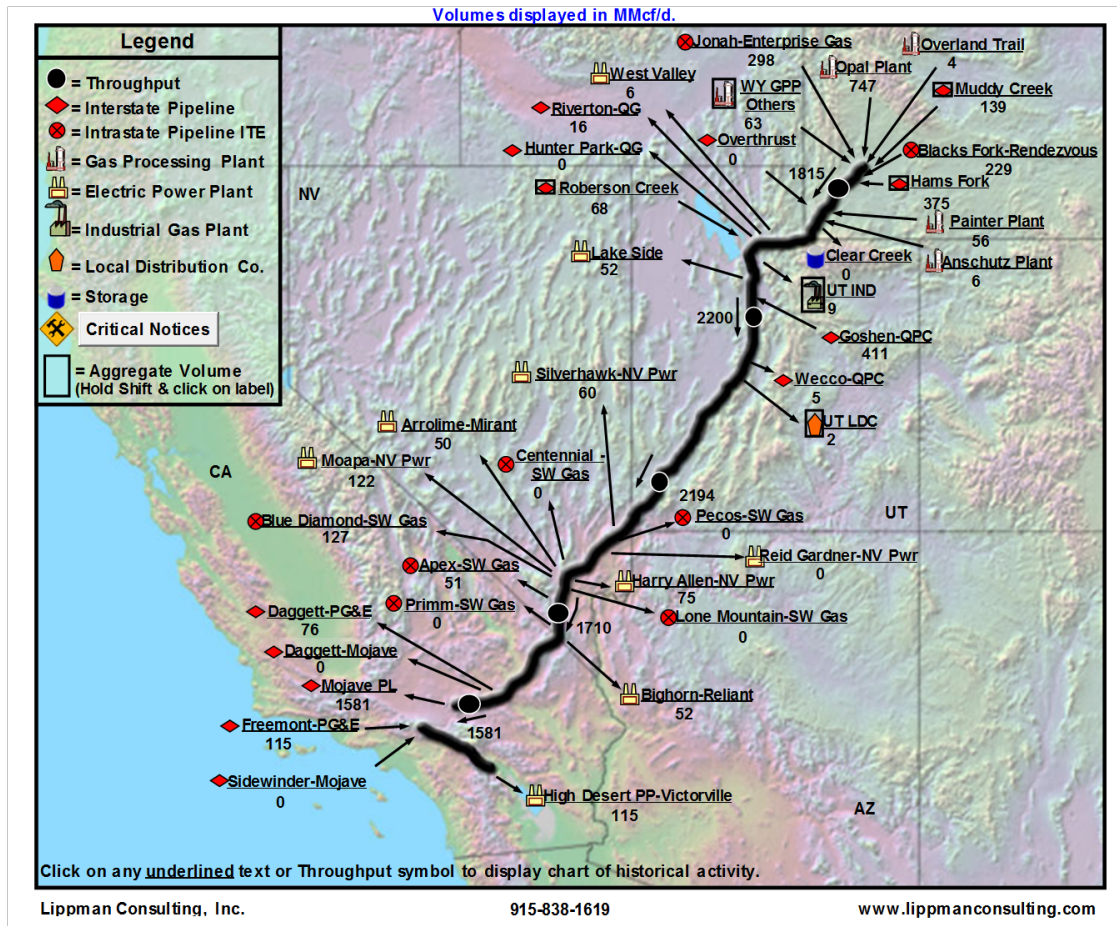


Figure 4.7: Kern River System Map from LCI Inc.

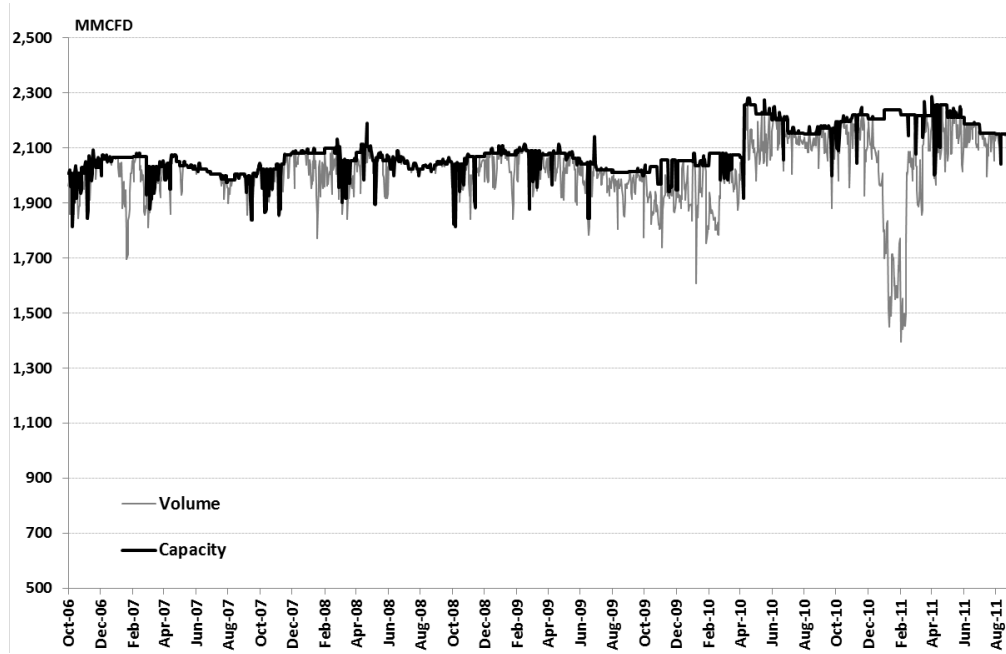


Figure 4.8: Kern River Veyo Station Throughput Capacity and Flows

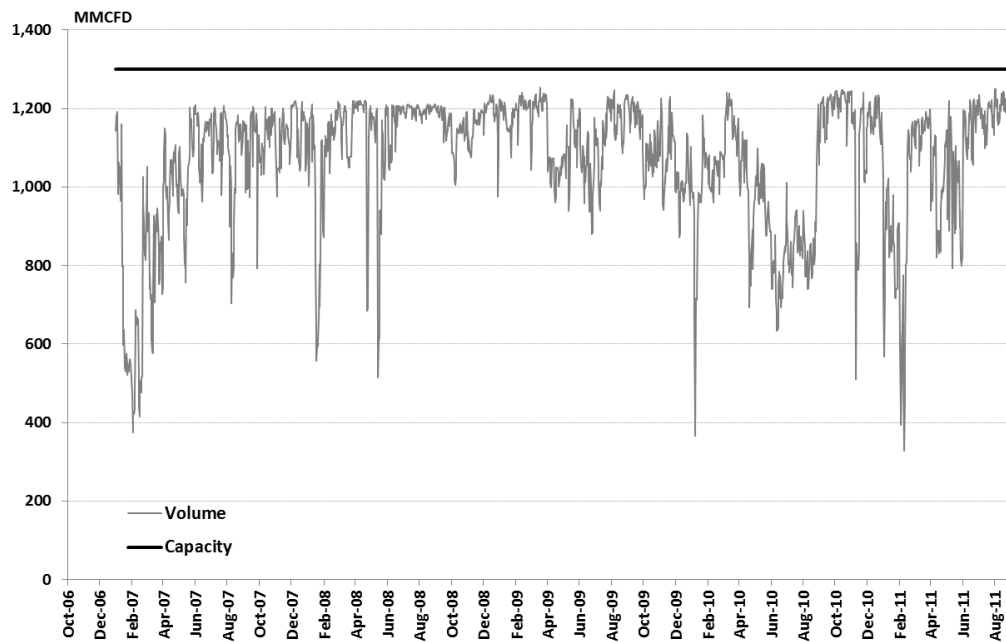


Figure 4.9: Transwestern West Throughput Capacity and Flows

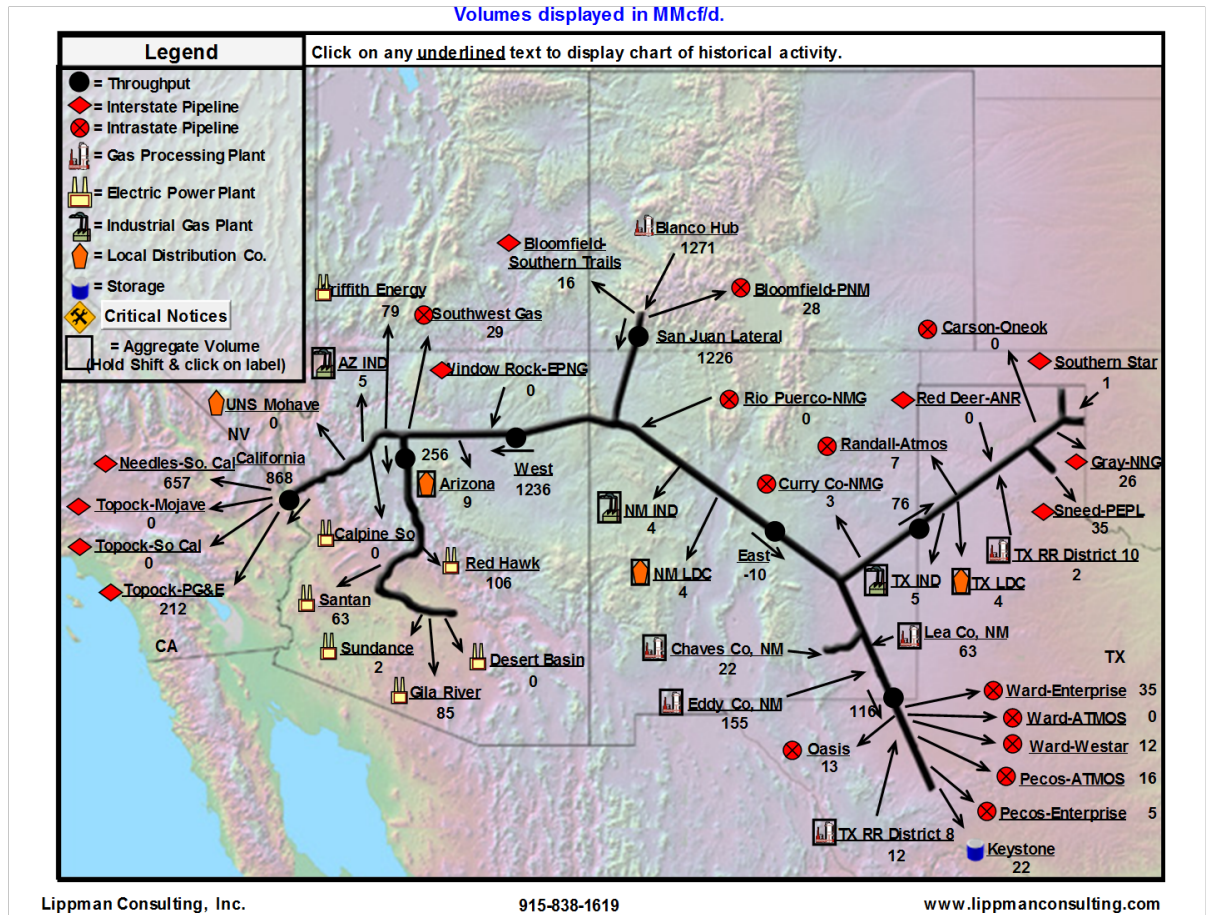


Figure 4.10: Transwestern System Map from LCI Inc.

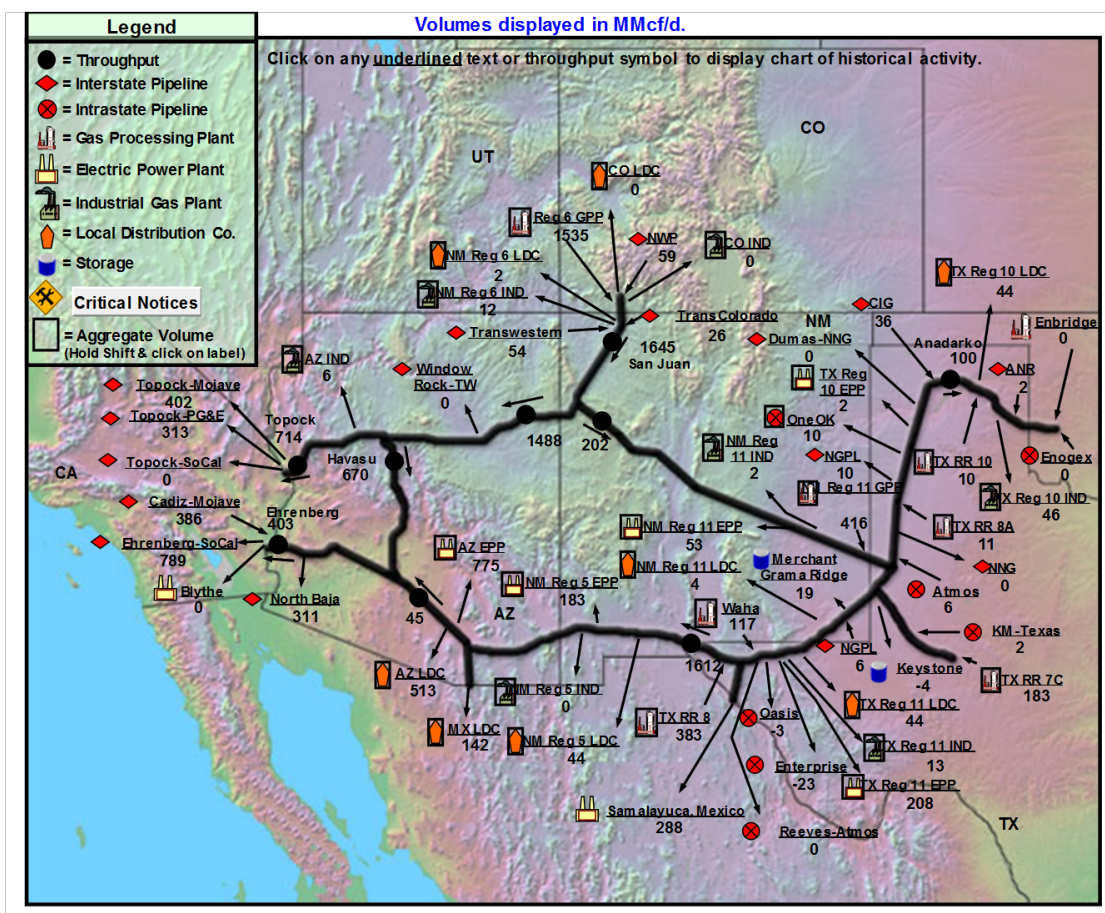


Figure 4.11: El Paso System Map from LCI Inc.

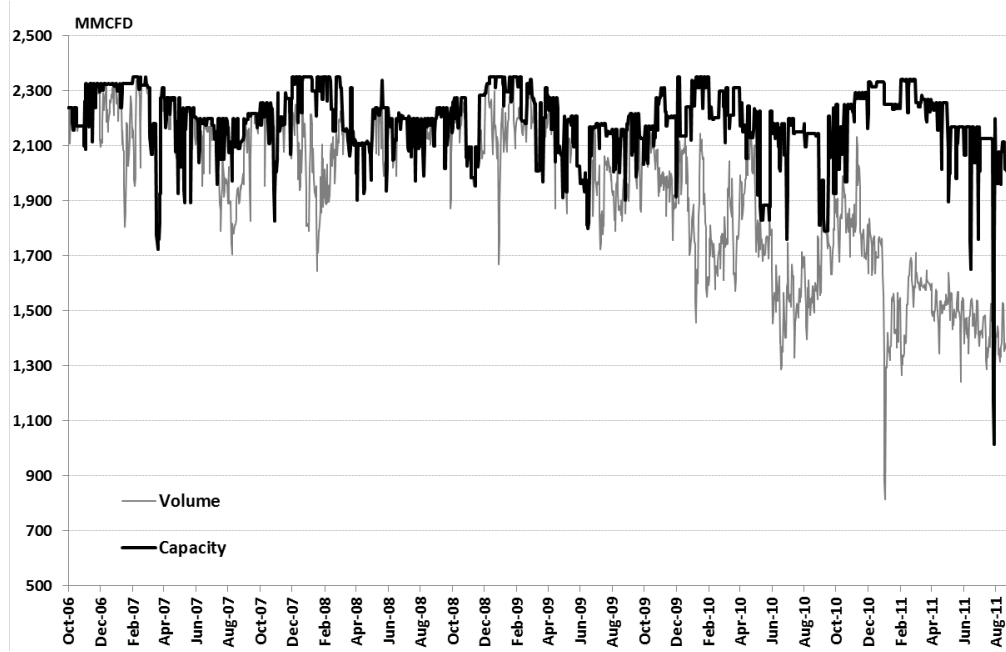


Figure 4.12: El Paso North Throughput Capacity and Flows

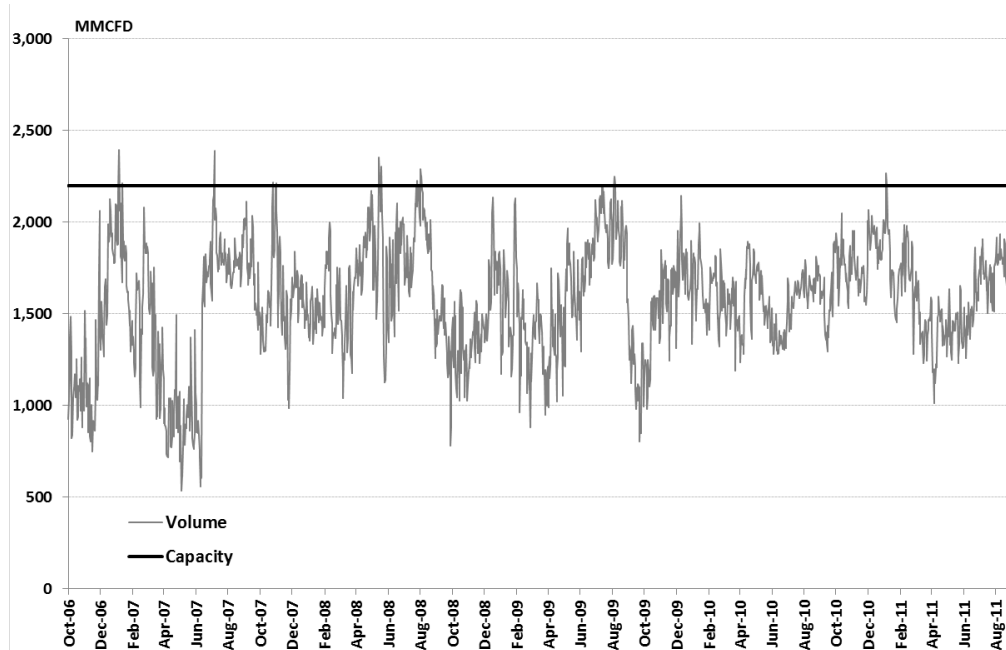


Figure 4.13: El Paso TX-NM Throughput Capacity and Flows

Regional Price Data Description

Summary statistics for 14 regional prices are reported in Table 4.9. These 14 prices form 196 market pairs that are tested for cointegration in Chapter 6.

Table 4.9: Summary Statistics Regional Prices

Variable	Region	Mean	Std. Dev.	Min.	Max.	N
Henry Hub Price	South	5.79	2.23	1.84	13.31	1250
Malin Price	Northwest	5.48	2.03	2.23	12.31	1252
PG&E Citygate Price	West	5.84	2.07	2.63	12.82	1252
So Cal Avg Price	West	5.42	2.02	2.22	12.68	1252
Katy Hub Price	Texas	5.60	2.13	1.95	12.98	1252
FGT Z3 Citygate Price	Southeast	6.73	2.65	2.26	18.00	1013
Chicago Citygate Price	Midwest	5.81	2.20	2.00	13.15	1252
NE Columbia Price	Northeast	6.01	2.32	1.94	13.85	1252
Kingsgate Price	Northwest	5.29	1.95	2.05	11.94	1221
Kern River Hub Price	Rockies	4.38	1.793	0.12	10.29	1252
Opal Hub Price	Rockies	4.39	1.794	0.12	10.26	1252
Stanfield Price	Northwest	5.40	2.00	2.14	12.08	1252
FGT Z3 AL-MS Price	Southeast	5.98	2.36	1.86	14.39	1252
Waha Hub Price	Texas	5.29	1.99	1.99	12.33	1252

EMPIRICAL SPECIFICATIONS

Working from the theoretical models in Chapter 4, empirical specifications are developed. As this thesis is concerned with effects in the wholesale market, wholesale supply and demand are shown below. From these reduced form models to be tested are developed. Cointegration tests of the Law of One Price are also developed.

Empirical Wholesale Supply and Demand Equations

Wholesale gas demand is shown in (5.1). The quantity of gas demanded (q^{cg}) is a function of the citygate price (P^{cg}), HDD, CDD, oil prices (P^o), industrial output prices (P^{mfg}), and total personal income (Y). Monthly fixed effects are included in $\vec{F}E$ to control for seasonality. Coal prices, industrial output prices, and personal income are not expected vary much at the daily level. The monthly value is used for each day within a month for these data series. Daily data on electricity prices was not available for this study. Monthly electricity prices were not included as the daily variation is expected to drive daily gas consumption. HDD and particularly CDD should control for electricity prices as weather is a key driver in daily electricity demand. Hydroelectric, renewable and nuclear generation are also excluded as daily data was not available. No attempt is made to control for efficiency gains do to the short term nature of the study and data sample.

$$\begin{aligned}
 q^{cg} = & \alpha_0 + \alpha_1 P_t^{cg} + \alpha_2 HDD_t + \alpha_3 CDD_t + \alpha_4 P_t^o \\
 & + \alpha_5 P_t^{coal} + \alpha_6 P^{mfg} + \alpha_7 Y_t + \vec{F}E \vec{\alpha}_8 + \epsilon_t
 \end{aligned}
 \tag{5.1}$$

Wholesale gas supply is shown in (5.2).

$$\begin{aligned}
 q^{cg} &= \beta_0 + \beta_1 P_t^{cg} + \beta_2 P_t^{hh} + \beta_3 Shutins_t + \vec{F} \vec{E}_t \vec{\beta}_4 + v_t \\
 q^{cg} &= q^c \text{ if } \beta_0 + \beta_1 P_t^{cg} + \beta_2 P_t^{hh} + \beta_3 Shutins_t + \vec{F} \vec{E}_t \vec{\beta}_4 + v_t \geq q^c
 \end{aligned} \tag{5.2}$$

These equations form a structural model. From these a reduced form model can be constructed.

Empirical Reduced Form Model

By setting the supply and demand equations, (5.1) and (5.2), equal to each other and solving for the equilibrium price, the reduced form model is as follows:

$$\begin{aligned}
 P^{cg} &= \pi_0 + \pi_1 BindingCap_t + \pi_2 HDD_t + \pi_3 CDD_t + \pi_4 P^o + \pi_5 P_t^{mfg} \\
 &\quad + \pi_6 Y_t + \pi_7 P_t^{hh} + \pi_8 Shutins_t + \vec{F} \vec{E} \vec{\pi}_9 + \mu_t
 \end{aligned} \tag{5.3}$$

Where the the variable *BindingCap* is a dummy variable equal to one if capacity is binding and zero otherwise. Binding can be set equal to one when the capacity factor is 100 percent, or some other threshold to be considered binding.¹

The effects of capacity constraints on prices can be tested directly. Estimating π_1 , in equation (5.3), will give an estimate of the average increase in daily prices from capacity constraints over the sample period. The increase in prices during a particular binding day, however, depends on demand. Given two days where pipeline capacity is constrained, the day with higher demand will be affected more by capacity constraints than a day with relatively lower demand. The effect of any one demand shifter should be greater during

¹This can be done both to increase the number observations used to estimate parameters during binding periods and to test the sensitivity of the results.

constrained periods than unconstrained periods, as can be seen in figure 5.1. Without constraints, the demand increase, which raises the price, also induces an increase in of gas quantity supplied so that price rises by β_{HDD} . With a binding constraint, however, there can be no supply response. Price will increase by $(\beta_{HDD} + \beta_{HDD*Bind})$. Interacting the *BindingCap* variable with demand shifters will more accurately estimate citygate prices, as shown in equation (5.3). Reduced form models for both the Florida and Southern California markets are estimated in Chapter 6.

$$\begin{aligned}
 P^{cg} = & \pi_0 + \pi_1 BindingCap_t + \pi_{11} BindingCap * HDD + \pi_{12} BindingCap * CDD_t + \\
 & \pi_{13} BindingCap * P_t^o + \pi_{14} BindingCap * P^{mfg} + \pi_{15} BindingCap * Y_t \\
 & + \pi_2 HDD_t + \pi_3 CDD_t + \pi_4 P^o + \pi_5 P_t^{mfg} + \pi_6 Y_t + \pi_7 P_t^{hh} \\
 & + \pi_8 Shutins_t + FE \pi_9 + \mu_t
 \end{aligned} \tag{5.4}$$

These reduced form models have dependent and independent variables that are likely non-stationary. This naturally raises the concern of a spurious regression. In Chapter 6 it is shown that the price series used in the reduced form models are cointegrated. Because the price are cointegrated, the regression results are consistent and a spurious regression is not a concern (Greene and Zhang, 2011).

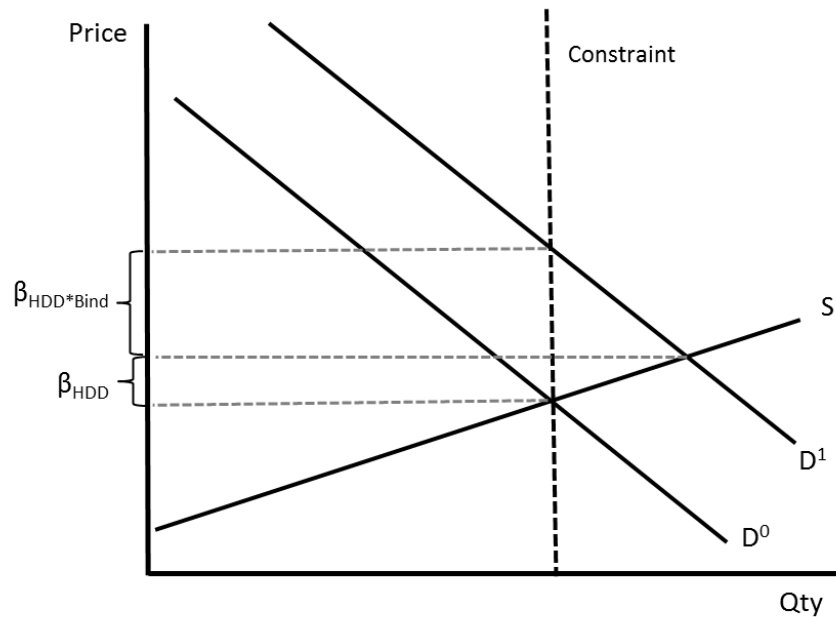


Figure 5.1: Greater Effect of Demand Shifters with Binding Constraints

Testing the Law of One Price - Cointegration

Two prices are cointegrated if they move together in a stable long-term relationship. More technically, two nonstationary series of data are cointegrated if there exists a linear relationship between them that is stationary (Engle and Granger, 1987). Cointegration lends itself to testing the Law of One Price. Many price series are nonstationary. But if the Law of One Price holds, the difference in prices must be within the limits of arbitrage and transportation costs. That is, the relationship between prices must be stationary if the Law of One Price holds.

A series of prices, P_t , is stationary if its autoregressive parameter, ρ from the autoregressive equation (5.5), is less than one. If $\rho \geq 1$, then the series has a unit root and is nonstationary. If the prices must be differenced d times to obtain a stationary series, then

the series is integrated of order d or $I(d)$, (De Vany and Walls, 1993). For example, a series that must be differenced three times before becoming stationary is $I(3)$.

$$P_t = \rho P_{t-1} + \mu_t \quad (5.5)$$

An Augmented Dickey-Fuller test (ADF) will test for unit roots (5.6). The null hypothesis is that the series is nonstationary. Critical values for this test are negative. The test statistic must be more negative than the critical value to reject nonstationarity.

$$\Delta P_t = - \sum_{i=1}^n \theta_i P_{t-i} + \mu_t \quad (5.6)$$

Two nonstationary price series, P_{it} which is $I(i)$ and P_{jt} which is $I(j)$, are cointegrated if there exists a linear relationship, as in equation (5.7), that produces errors that are $I(i-j)$ (Engle and Granger, 1987).

$$\begin{aligned} P_{it} &= \beta_0 + \beta_1 P_{jt} + \varepsilon_t \\ \varepsilon_t &= P_{it} - \beta_0 - \beta_1 P_{jt} \end{aligned} \quad (5.7)$$

Equation (5.7) represents the cointegrating regression. If P_{it} and P_{jt} represent natural gas prices at two different locations, then the cointegrating parameter, β_1 , should equal $1/(1 - \% \text{ Fuel Charge})$. Statistical tests on the value of this parameter, unfortunately, are not reliable as the standard errors are not consistent, (De Vany and Walls, 1993). Cointegration, however, can be tested by running an ADF test on the errors in equation (5.7), also known as an Engle and Granger (1987) cointegration test. Results from these tests on natural gas wholesale price are shown in Chapter 6.

EMPIRICAL RESULTS

Florida - Reduced Form Regressions

The reduced form equation (5.3) is estimated for Florida using FGT Zone 3 Citygate Price as the dependent variable. Table 6.1 shows the results using binding capacity across both FGT and Gulf South pipelines (a binary variable) as the variable of interest.¹

The coefficients on HDD (0.19\$/MMBtu) and CDD (0.12\$/MMBtu) are positive and statistically significant, as expected. Looking at the 75th percentile for weather, these equate to a 0.50\$/MMBtu effect for HDD and 1.89\$/MMBtu effect for CDD.

The coefficient on Henry Hub prices is also statistically significant and positive. The estimate near one seems plausible and in line with the Law of One Price.

The estimate on Hurricane Shut-ins is not significantly different from zero. Perhaps this is because the effects of hurricanes are captured in Henry Hub prices. None of the coefficients on Coal Price, Personal Income, and Industrial Price are statistically different from zero. This is probably due to trying to use variables with monthly variation to explain a variable with daily variation. The estimate on WTI Price, surprisingly, is also not significantly different from zero.

Binding capacity has a large and statistically significant (at the 1 percent level) effect on FGT Zone 3 Citygate Prices. This result is robust to model specification changes and monthly fixed effects. On average, FGT Zone 3 Citygate prices were about \$2.50/MMBtu higher (42 percent of average the Henry Hub price over the sample period) when total pipeline capacity into Florida was full than they otherwise would have been.

Table 6.2 reports the effects of either pipeline binding (FGT or Gulf South). The coefficients on the control variables are qualitatively the same as in table 6.1 and the same amount

¹Corrections for autocorrelation are made using the Cochrane-Orcutt procedure.

of confidence may be taken in the estimates of interest. The effects of either pipeline binding are also large and statistically significant at the 1 percent level. The average effect of FGT binding was to increase Zone 3 prices by \$0.67/MMBtu over the sample period. The average effect of Gulf South binding was to increase prices by \$1.40/MMBtu. These results are also robust to model specification.

The effect of binding capacity is not uniform across all constrained days. Demand might be higher or lower in different constrained periods. A model where demand shifters are interacted with the binding variable is estimated in table 6.3. There is no supply response to increasing demand during constrained periods, therefore the effects of demand shifters on equilibrium prices should be greater in constrained periods than in unconstrained periods. This can be seen in columns (2) through (6) of table 6.3, particularly with respect to the weather parameters. Column (1) shows results when total capacity was 100 percent full, which only occurred 16 days in the sample (Table 4.3).

The negative results on HDD and CDD run counter to the theory. Dropping the required capacity factor to be considered binding increases the number of observations used to estimate these interaction parameters. There are 64 days at 99 percent and 205 days at 95 percent. The estimates on these interaction variables, with the exception of Industrial Price, are all positive or not statistically different than zero for the estimations using 99 to 95 percent as the conditions for capacity to be considered binding. This means that the effect of a demand shifter on equilibrium prices during constrained periods is greater than unconstrained periods, as expected. The effect of HDD and CDD on prices doubles or more than doubles (depending on what capacity factor is used to define binding) during constrained periods as compared to unconstrained periods.

Table 6.1: FL Reduced Form Regression - Combined Capacity Factors

VARIABLES	(1) FGT Price	(2) FGT Price	(3) FGT Price	(4) FGT Price	(5) FGT Price	(6) FGT Price
Binding Capacity	2.503*** (0.238)	2.498*** (0.242)	2.487*** (0.242)	2.488*** (0.242)	2.478*** (.241)	2.511*** (0.239)
Henry Hub Price	1.015*** (0.054)	1.003*** (0.056)	1.018*** (0.055)	1.016*** (0.056)	1.064*** (0.031)	1.008*** (0.055)
WTI Price	0.050 (0.044)	0.052 (0.046)	0.019 (0.035)	0.019 (0.035)		0.054 (0.045)
Coal Price	0.028 (0.482)	0.085 (0.515)	-0.140 (0.478)	-0.006 (0.668)		-0.008 (0.492)
Personal Income	0.320 (0.675)	0.469 (0.709)	0.135 (0.649)	0.003 (0.740)		0.300 (0.682)
Industrial Price	-0.0296 (0.033)	-0.0364 (0.034)				-0.0309 (0.034)
Industrial Output				0.0118 (0.041)		
HDD	0.185*** (0.014)	0.189*** (0.015)	0.188*** (0.015)	0.188*** (0.015)	0.187*** (0.014)	0.186*** (0.014)
CDD	0.109*** (0.013)	0.119*** (0.020)	0.120*** (0.020)	0.120*** (0.020)	0.120*** (0.020)	0.110*** (0.016)
Hurricane Shut-ins	0.025 (0.100)	0.079 (0.109)	0.031 (0.102)	0.043 (0.110)		0.040 (0.105)
Constant	-2.713 (8.614)	-4.076 (9.167)	-2.200 (9.112)	-2.538 (9.176)	-0.931 (0.340)	-2.284 (8.736)
Monthly FE	No	Yes	Yes	Yes	Yes	No
Quarterly FE	No	No	No	No	No	Yes
Observations	710	710	710	710	710	710
R-squared	0.680	0.693	0.688	0.682	0.689	0.682

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.2: FL Reduced Form Regression - Individual Pipeline Capacity Factors

VARIABLES	(1) FGT Price	(2) FGT Price	(3) FGT Price	(4) FGT Price
FGT Binding	0.719*** (0.203)		0.669*** (0.196)	0.660*** (0.196)
Gulf Binding		1.417*** (0.168)	1.408*** (0.167)	1.397*** (0.167)
Henry Hub Price	1.016*** (0.057)	1.002*** (0.056)	0.996*** (0.054)	1.011*** (0.034)
WTI Price	0.038 (0.047)	0.042 (0.047)	0.051 (0.045)	-0.014 (0.034)
Coal Price	-0.0004 (0.515)	0.329 (0.520)	0.205 (0.497)	0.138 (0.377)
Personal Income	0.294 (0.720)	0.763 (0.716)	0.678 (0.684)	0.192 (0.717)
Industrial Price	-0.020 (0.035)	-0.037 (0.034)	-0.040 (0.033)	
Industrial Output				0.015 (0.040)
HDD	0.192*** (14.73)	0.188*** (14.90)	0.184*** (14.75)	0.183*** (14.79)
CDD	0.116*** (0.013)	0.118*** (0.020)	0.112*** (0.020)	0.113*** (0.020)
Hurricane Shut-ins	0.003 (0.107)	0.079 (0.111)	0.098 (0.106)	0.059 (0.107)
Constant	-3.125 (9.183)	-8.303 (9.255)	-6.652 (8.850)	-5.144 (8.902)
Monthly FE	No	Yes	Yes	Yes
Observations	710	710	710	710
R-squared	0.637	0.684	0.705	0.889

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.3: FL Reduced Form Regression with Interactions - Combined Capacity Factors

Capacity Factor VARIABLES	(1) 100% FGT Price	(2) >99% FGT Price	(3) >98% FGT Price	(4) >97% FGT Price	(5) >96% FGT Price	(6) >95% FGT Price
Binding Capacity	-188.0*** (35.85)	-49.65** (16.14)	-78.70*** (19.56)	-41.75*** (12.34)	-10.87* (10.68)	9.87 (11.58)
Binding*WTI	1.253** (0.564)	0.638* (0.356)	0.453* (0.256)	0.755*** (0.118)	0.662*** (0.108)	0.065 (0.087)
Binding*HDD	-0.521*** (0.129)	0.186*** (0.063)	0.337*** (0.051)	0.347*** (0.042)	0.283*** (0.034)	0.249*** (0.035)
Binding*CDD	-0.767*** (0.142)	0.128* (0.072)	0.181*** (0.058)	0.247*** (0.050)	0.229*** (0.039)	0.240*** (0.039)
Binding*Income	13.20*** (2.63)	3.89** (1.49)	6.22*** (1.47)	2.30** (0.11)	0.97 (1.00)	-3.39*** (1.04)
Binding*Coal Price	9.504*** (1.528)	3.162*** (0.943)	4.096*** (1.000)	2.534*** (0.836)	1.639** (0.783)	-1.648** (0.793)
Binding*Industrial Price	-0.128 (0.100)	-0.214** (0.097)	-0.232** (0.115)	-0.107 (0.091)	-0.097 (0.085)	0.354*** (0.074)
Henry Hub Price	0.979*** (0.051)	1.006*** (0.052)	1.017*** (0.038)	1.013*** (0.038)	1.010*** (0.042)	1.023*** (0.054)
WTI Price	0.0286 (0.042)	0.0436 (0.044)	0.0558* (0.033)	0.0587* (0.034)	0.0514 (0.037)	0.0583 (0.045)
Coal Price	0.183 (0.471)	-0.023 (0.475)	-0.103 (0.342)	-0.151 (0.352)	-0.344 (0.389)	0.115 (0.514)
Personal Income	0.844 (0.651)	0.3422 (0.653)	7.54e-02 (0.471)	0.086 (0.486)	0.226 (0.538)	0.340 (0.707)
Industrial Price	-0.0272 (0.031)	-0.0281 (0.031)	-0.0345 (0.023)	-0.0365 (0.023)	-0.0332 (0.026)	-0.0463 (0.033)
HDD	0.177*** (0.013)	0.190*** (0.015)	0.149*** (0.012)	0.156*** (0.013)	0.153*** (0.014)	0.147*** (0.016)
CDD	0.122*** (0.018)	0.125*** (0.018)	0.110*** (0.017)	0.109*** (0.017)	0.104*** (0.018)	0.090*** (0.021)
Hurricane Shut-ins	0.0580 (0.099)	0.092 (0.101)	0.139* (0.073)	0.144* (0.075)	0.124 (0.082)	0.115 (0.106)
Constant	-9.509 (8.400)	-2.819 (8.482)	1.294 (6.149)	1.496 (6.349)	-0.831 (7.009)	-1.595 (9.175)
Monthly FE	Yes	Yes	Yes	Yes	Yes	Yes
Observations	710	710	710	710	710	710
R-squared	0.726	0.730	0.838	0.8425	0.814	0.723

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Florida - Cointegration Tests

Augmented Dickey-Fuller tests are run on each price series independently. No constant, constant, and constant plus trend specifications are used. These tests fail to reject unit roots at the 5% level in both Henry Hub and FGT Zone 3 Citygate prices (table 6.6).² Unit roots on the first differenced prices are rejected at the 1% significance level. Both price series are integrated of order one, $I(1)$.

Table 6.7 shows that Henry Hub and FGT prices are cointegrated when capacity factors are less than 98 percent on FGT and Gulf South.³ The relationship between prices is stationary, $I(0)$, under various specifications at the 1 percent level. The specification in Column (2) is used to test for cointegration at various capacity factors as it is consistent with the terms of natural gas transportation contracts.⁴ Table 6.4 shows these tests for various non-binding levels of capacity. Prices in these non-binding periods are found to be cointegrated, consistent with the Law of One Price. Moreover, the entire price series, including periods of binding capacity, is also cointegrated. This is notable because previous studies identify pipeline bottlenecks as breakdowns in cointegration. They would not identify the bottlenecks going into Florida.

Tests during periods of binding capacity are shown in table 6.5. Various capacity factors are used to allow for a larger number of consecutive observations than tests only using periods where capacity factors are at 100 percent. All the tests using capacity factors greater than 92 percent fail to reject a non-stationary relationship between Henry Hub and Zone 3

²FGT Zone 3 prices are tested with 19 lags, the optimal level of lags chosen by a Ng-Perron test. First differenced FGT Zone 3 prices have 18 lags.

³That is, all observations where FGT or Gulf South have a capacity factor greater than or equal to 98 percent are thrown out of the test.

⁴Those terms being a fixed charge per MMBtu plus a percentage of fuel shipped.

prices at a 5 percent level. This supports the contention that capacity constraints are causing the breakdowns in the Law of One Price.

The estimates on Henry Hub Price in the table 6.4 cointegrating regressions are consistent with the percent fuel charge used in transportation contracts. The estimates in non-binding periods imply a fuel charge around 4 to 6 percent, higher than the 3.1 percent cost on FGT. This could be because FGT does not directly connect to Henry Hub. Prices at FGT Zone 1 (the beginning of the pipeline) would be better for testing the 3.1 percent fuel charge. Unfortunately those prices were not available for this thesis. The estimates of the constants represent the average fixed rate charge (per MMBtu) from all types of transport services paid by shippers over the sample period.

As capacity factors rise and constraints become binding (table 6.5), the estimated coefficient on Henry Hub Price rises significantly. The estimated constant also starts to become meaningless as an estimate of the average fixed rate charge. These results are consistent with prices at FGT Zone 3 and Henry Hub no longer being connected by transportation costs (i.e. the Law of One Price stops holding) as market integration breaks down.

Table 6.4: FL Cointegration Tests - Various Non-Binding Capacity Factors

Capacity Factor VARIABLES	(1) All FGT Price	(2) <98% FGT Price	(3) <95% FGT Price	(4) <92% FGT Price	(5) <90% FGT Price	(6) <85% FGT Price	(7) <80% FGT Price	(8) <75% FGT Price
Henry Hub Price	1.016*** (0.016)	1.040*** (0.010)	1.054*** (0.010)	1.063*** (0.008)	1.065*** (0.008)	1.061*** (0.007)	1.048*** (0.006)	1.040*** (0.005)
Constant	0.813*** (0.106)	0.501*** (0.069)	0.335*** (0.066)	0.212*** (0.060)	0.167*** (0.057)	0.134** (0.053)	0.139*** (0.045)	0.145*** (0.035)
ADF Ctritical Stat 1%	-3.43	-3.43	-3.43	-3.43	-3.44	-3.45	-3.45	-3.47
ADF Ctritical Stat 5%	-2.86	-2.86	-2.86	-2.86	-2.87	-2.87	-2.88	-2.88
ADF Test Stat	-9.91***	-13.31***	-14.93***	-16.50***	-11.79***	-8.27***	-10.85***	-8.16***
ADF P-Value	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Observations	710	642	552	503	469	409	311	232
R-squared	0.802	0.917	0.936	0.954	0.961	0.970	0.982	0.991

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.5: FL Cointegration Tests - Various Binding Capacity Factors

Capacity Factors	All	>80%	>85%)	>90%	>92%	>95%	>98%
VARIABLES	(1) FGT Price	(2) FGT Price	(3) FGT Price	(4) FGT Price	(5) FGT Price	(6) FGT Price	(7) FGT Price
Henry Hub Price	1.016*** (0.016)	1.098*** (0.031)	1.170*** (0.049)	1.300*** (0.074)	1.566*** (0.111)	1.800*** (0.162)	1.999*** (0.369)
Constant	0.813*** (0.106)	0.872*** (0.186)	0.719*** (0.266)	0.321 (0.374)	-0.758 (0.538)	-1.591** (0.774)	-1.766 (1.855)
ADF Ctritical Stat 5%	-2.86	-2.88	-2.88	-2.89	-2.89	-2.89	-2.96
ADF Test Stat	-9.91***	-7.27***	-5.79***	-5.52***	-2.47	-2.18	-2.15
ADF P-Value	0.000***	0.000***	0.000***	0.000***	0.124	0.212	0.227
Observations	710	323	238	182	147	98	41
R-squared	0.802	0.724	0.622	0.538	0.472	0.439	0.308

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 6.6: FL Unit Root Tests

	No Constant	Constant	Constant/Trend
<u>Critical Values</u>			
10% Significance	-1.62	-2.57	-3.12
5% Significance	-1.95	-2.86	-3.41
1% Significance	-2.58	-3.43	-3.96
<u>Test Stats</u>			
Henry Hub	3.19 (n/a)	-1.05 (0.734)	-3.25* (0.076)
FGT Zone 3	-1.070 (n/a)	-2.128 (0.233)	-2.959 (0.144)
Henry Hub Differenced	-29.63*** (n/a)	-29.69*** (0.0000)	-29.85*** (0.0000)
FGT Zone 3 Differenced	-9.190*** (n/a)	-9.193*** (0.0000)	-9.192*** (0.0000)
p-values in parentheses			
*** p<0.01, ** p<0.05, * p<0.1			

Southern California - Reduced Form Regressions

The reduced form equation (5.3) is estimated using Southern California Citygate Price as the dependent variable. Table 6.8 shows the results.⁵

The coefficients on HDD (0.01\$/MMBtu) and CDD (0.02\$/MMBtu), though smaller than in Florida, are positive and statistically significant, as expected. Looking at the 75th percentile for weather, these equate to a 0.19\$/MMBtu effect for HDD and 0.11\$/MMBtu effect for CDD.

⁵Corrections for autocorrelation are made using the Cochrane-Orcutt procedure.

Table 6.7: FL Cointegration Tests - Capacity Factors less than 98%

VARIABLES	(1) FGT Price	(2) FGT Price	(3) FGT Price
Henry Hub Price	1.108*** (0.004)	1.040*** (0.010)	1.044*** (0.014)
Trend			3.87e-05 (7.30e-05)
Constant		0.501*** (0.069)	0.437*** (0.138)
ADF Ctritical Stat 1%	-3.43	-3.43	-3.43
ADF Test Stat	-13.244***	-13.308***	-13.285***
Observations	642	642	642
R-squared	0.988	0.917	0.917

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Henry Hub Price has the expected positive effect. Industrial Price is also in line with theory having a positive effect on gas prices. WTI Price is only statistically significantly different from zero in column (3) when Industrial Price is dropped. The Coal Price coefficient is significant and negative, which theory. This may be due to the fact that, over the sample period, coal prices in the Rockies were trending higher as natural gas prices were trending down. The statistically significant negative effect of Hurricane Shut-ins is also surprising. This result appears to be driven by hurricanes Gustav and Ike in late 2008, when natural gas prices were plummeting from their highs (see figure 6.1).

The results of interest are robust to model specification changes and the inclusion of monthly fixed effects. Capacity factors greater than or equal to 95 percent across all pipelines (Kern River, El Paso, and Transwestern) had a statistically significant effect (at the 1 percent level) on Southern California Citygate Prices. At about 0.17\$/MMBtu (2.9 percent of average Henry Hub Prices over the period), the effect is much smaller than in

Florida. The result is not robust, however, to changes in the capacity factor used to define binding periods (table 6.9). At capacity factors above 96 percent the effect is not statistically different than zero at the 5 percent level. This could be from the lack of days, only 15, where total import capacity factors into Southern California are greater than or equal to 97 percent.

Table 6.10 reports the effects of binding capacity of the pipelines individually (Kern River, El Paso North, El Paso Texas into New Mexico, and Transwestern). The estimates on the control variables are qualitatively the same as in table 6.8. The effects of 100 percent capacity factors are statistically significant for El Paso North (0.04\$/MMBtu), El Paso TX-NM (0.11\$/MMBtu), and Transwestern (0.28\$/MMBtu). The effect of El Paso North binding is economically insignificant, the effect of El Paso TX-NM binding was 1.9 percent of the average Henry Hub price and the effect Transwestern binding was about 4.8 percent of the average Henry Hub prices during the period. These results, too, are sensitive to the capacity factor chosen to define binding, reported in table 6.11. Binding Kern River is never significant. Binding El Paso North loses significance when the capacity factor requirement is dropped below 99 percent. Binding El Paso TX-NM is significant throughout, though the point estimate ranges from 0.07\$/MMBtu to 0.19\$/MMBtu. Binding Transwestern loses significance for capacity factor requirements below 97 percent.

Table 6.8: California Reduced Form Regression - Combined Capacity Factors 95%

VARIABLES	(1) SoCal Price	(2) SoCal Price	(3) SoCal Price	(4) SoCal Price	(5) SoCal Price
Binding Cap 95%	0.165*** (0.049)	0.173*** (0.050)	0.167*** (0.050)	0.173*** (0.050)	0.175*** (0.050)
Henry Hub Price	0.865*** (0.018)	0.860*** (0.018)	0.852*** (0.018)	0.925*** (0.011)	0.920*** (0.013)
WTI Price	0.00572 (0.013)	0.00146 (0.013)	0.0361*** (0.00871)		
Coal Price	-1.044*** (0.286)	-1.146*** (0.311)	-0.727** (0.293)		
Personal Income	-3.25e-03 (0.144)	1.30e-03 (0.140)	0.231* (0.127)		
Industrial Price	0.0211*** (0.00688)	0.0253*** (0.00711)			
HDD	0.014*** (0.003)	0.013*** (0.004)	0.013*** (0.004)	0.013*** (0.004)	0.012*** (0.004)
CDD	0.012* (0.006)	0.019** (0.007)	0.018** (0.007)	0.018** (0.008)	0.018** (0.008)
Hurricane Shut-ins	-0.252*** (0.0326)	-0.287*** (0.0333)	-0.248*** (0.0321)	-0.229*** (0.0359)	
Constant	-0.146 (1.688)	-0.272 (1.632)	-1.834 (1.601)	0.161 (0.128)	0.186 (0.146)
Monthly FE	No	Yes	Yes	Yes	Yes
Observations	966	966	966	966	966
R-squared	0.903	0.912	0.910	0.884	0.840

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.9: California Reduced Form Regression - Combined Various Capacity Factors

Capacity Factor VARIABLES	(1) 100% SoCal Price	(2) 99% SoCal Price	(3) 98% SoCal Price	(4) 97% SoCal Price	(5) 96% SoCal Price	(6) 95% SoCal Price	(7) 90% SoCal Price
Binding Capacity	0.064 (0.220)	0.003 (0.159)	0.095 (0.111)	0.104* (0.062)	0.149*** (0.047)	0.173*** (0.050)	0.129*** (0.029)
Henry Hub Price	0.860*** (0.018)	0.860*** (0.018)	0.861*** (0.018)	0.861*** (0.018)	0.860*** (0.018)	0.860*** (0.018)	0.867*** (0.018)
WTI Price	0.0039 (0.013)	0.0038 (0.013)	0.0028 (0.013)	0.0029 (0.013)	0.0029 (0.013)	0.0015 (0.013)	-0.0011 (0.013)
Coal Price	-1.172*** (0.311)	-1.175*** (0.311)	-1.166*** (0.312)	-1.159*** (0.310)	-1.156*** (0.310)	-1.146*** (0.311)	-1.065*** (0.309)
Personal Income	3.06e-03 (0.141)	5.22e-03 (0.140)	1.66e-03 (0.141)	-5.21e-03 (0.140)	-2.47e-03 (0.140)	1.30e-03 (0.140)	-1.96e-02 (0.139)
Industrial Price	0.0244*** (0.007)	0.0244*** (0.007)	0.0248*** (0.007)	0.0250*** (0.007)	0.0250*** (0.007)	0.0253*** (0.007)	0.0264*** (0.007)
HDD	0.014*** (0.004)	0.014*** (0.004)	0.014*** (0.004)	0.014*** (0.004)	0.013*** (0.004)	0.013*** (0.004)	0.013*** (0.004)
CDD	0.018** (0.007)	0.019** (0.007)	0.018** (0.007)	0.018** (0.007)	0.018** (0.007)	0.019** (0.007)	0.017** (0.007)
Hurricane Shut-ins	-0.288*** (0.033)	-0.288*** (0.033)	-0.289*** (0.033)	-0.289*** (0.033)	-0.289*** (0.033)	-0.287*** (0.033)	-.289*** (0.033)
Constant	-0.208 (1.635)	-0.229 (1.635)	-0.228 (1.636)	-0.168 (1.629)	-0.195 (1.627)	-0.272 (1.632)	-0.233 (1.617)
Monthly FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Observations	966	966	966	966	966	966	966
R-squared	0.912	0.912	0.912	0.913	0.913	0.912	0.914

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.10: California Reduced Form Regression - Individual Pipeline Capacity Factors 100%

VARIABLES	(1) SoCal Price	(2) SoCal Price	(3) SoCal Price	(4) SoCal Price	(5) SoCal Price
Binding Kern River	-0.00474 (0.0193)				-0.00710 (0.0193)
Binding El Paso North		0.0440** (0.0217)			0.0442** (0.0218)
Binding El Paso TX-NM			0.113* (0.0620)		0.112* (0.0618)
Binding Transwestern				0.271** (0.123)	0.276** (0.126)
Henry Hub Price	0.860*** (0.0184)	0.858*** (0.0186)	0.861*** (0.0184)	0.856*** (0.0182)	0.856*** (0.0185)
WTI Price	0.00366 (0.0131)	0.00247 (0.0132)	0.00213 (0.0131)	0.00799 (0.0131)	0.00468 (0.0133)
Coal Price	-1.178*** (0.311)	-1.152*** (0.316)	-1.153*** (0.311)	-1.142*** (0.308)	-1.100*** (0.313)
Personal Income	4.71e-03 (0.140)	3.95e-03 (0.142)	-1.51e-03 (0.140)	-2.46e-02 (0.139)	-3.40e-02 (0.142)
Industrial Price	0.0245*** (0.007)	0.0249*** (0.007)	0.0251*** (0.007)	0.0247*** (0.007)	0.0261*** (0.007)
HDD	0.014*** (0.004)	0.014*** (0.004)	0.013*** (0.004)	0.014*** (0.004)	0.013*** (0.004)
CDD	0.019** (0.007)	0.019** (0.007)	0.018** (0.007)	0.020*** (0.007)	0.019*** (0.007)
Hurricane Shut-ins	-0.288*** (0.033)	-0.285*** (0.034)	-0.288*** (0.033)	-0.279*** (0.033)	-0.275*** (0.034)
Constant	-0.227 (1.634)	-0.266 (1.660)	-0.213 (1.635)	-0.0150 (1.614)	-0.0328 (1.643)
Monthly FE	Yes	Yes	Yes	Yes	Yes
Observations	966	966	966	966	966
R-squared	0.912	0.910	0.912	0.914	0.912

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.11: California Reduced Form Regression - Individual Pipeline Various Capacity Factors

VARIABLES	(1) 100% SoCal Price	(2) 99% SoCal Price	(3) 98% SoCal Price	(4) 97% SoCal Price	(5) 96% SoCal Price	(6) 95% SoCal Price	(7) 90% SoCal Price
Binding Kern River	-0.0071 (0.019)	0.0032 (0.016)	0.0071 (0.016)	0.0002 (0.018)	0.0192 (0.019)	0.0286 (0.022)	0.0142 (0.041)
Binding El Paso North	0.0442** (0.022)	0.0572*** (0.021)	0.0305 (0.021)	0.0226 (0.022)	0.0271 (0.023)	0.0130 (0.024)	0.0080 (0.026)
Binding El Paso TX-NM	0.112* (0.062)	0.163*** (0.059)	0.191*** (0.053)	0.171*** (0.046)	0.156*** (0.038)	0.159*** (0.035)	0.0740** (0.031)
Binding Transwestern	0.276** (0.126)	0.266** (0.128)	0.270** (0.124)	0.275** (0.124)	0.136 (0.096)	0.0389 (0.045)	0.0031 (0.020)
Henry Hub Price	0.856*** (0.019)	0.856*** (0.019)	0.856*** (0.018)	0.855*** (0.018)	0.854*** (0.018)	0.856*** (0.018)	0.860*** (0.019)
WTI Price	0.0047 (0.013)	0.0036 (0.013)	0.0050 (0.013)	0.0056 (0.013)	0.0061 (0.013)	0.0058 (0.013)	0.0023 (0.013)
Coal Price	-1.100*** (0.313)	-1.060*** (0.316)	-1.087*** (0.309)	-1.101*** (0.309)	-1.118*** (0.309)	-1.144*** (0.311)	-1.132*** (0.314)
Personal Income	-3.40e-02 (0.142)	-3.22e-02 (0.143)	-3.19e-02 (0.140)	-2.32e-02 (0.140)	-6.03e-03 (0.139)	8.99e-03 (0.140)	2.81e-03 (0.141)
Industrial Price	0.0261*** (0.007)	0.0265*** (0.007)	0.0264*** (0.007)	0.0260*** (0.007)	0.0253*** (0.007)	0.0246*** (0.007)	0.0254*** (0.007)
HDD	0.013*** (0.004)	0.013*** (0.004)	0.014*** (0.004)	0.013*** (0.004)	0.013*** (0.004)	0.013*** (0.004)	0.013*** (0.004)
CDD	0.019*** (0.007)	0.019*** (0.007)	0.021*** (0.007)	0.020*** (0.007)	0.019*** (0.007)	0.018** (0.007)	0.017** (0.007)
Hurricane Shut-ins	-0.275*** (0.034)	-0.279*** (0.034)	-0.282*** (0.034)	-0.277*** (0.034)	-0.287*** (0.033)	-0.287*** (0.033)	-0.288*** (0.034)
Constant	-0.0328 (1.643)	-0.129 (1.662)	-0.113 (1.623)	-0.159 (1.622)	-0.295 (1.621)	-0.359 (1.635)	-0.344 (1.642)
Observations	966	966	966	966	966	966	966
R-squared	0.912	0.910	0.914	0.914	0.914	0.913	0.912

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

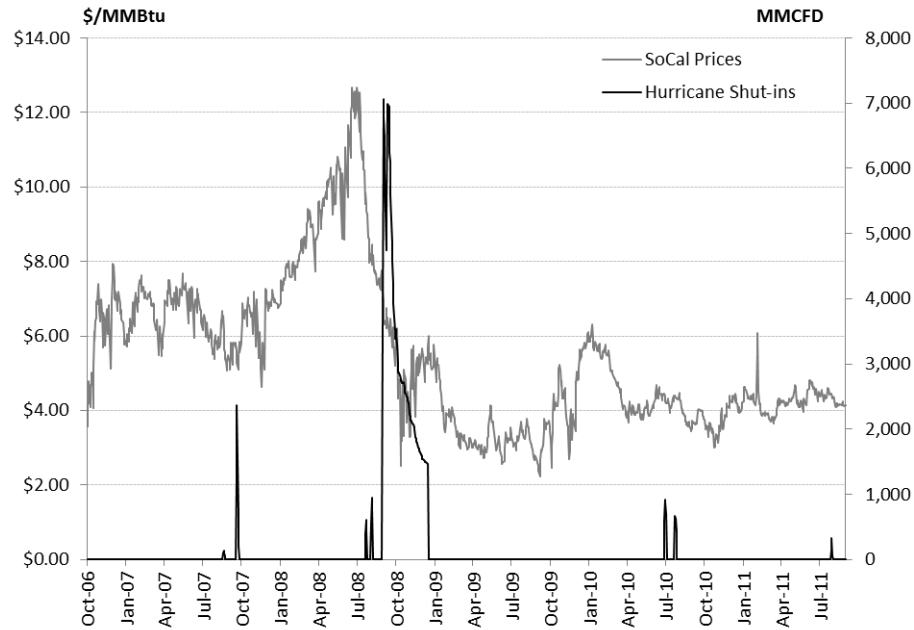


Figure 6.1: Hurricane Shut-ins 2001-2011

Southern California - Cointegration Tests

Augmented Dickey-Fuller tests were run on both Henry Hub and SoCal prices under no constant, constant, and constant plus trend specifications. As can be seen in table 6.14, These tests fail to reject unit roots at the 5 percent level in either price with the exception of SoCal prices under the constant plus trend specification. Unit roots on the first differenced prices are rejected at the 1 percent significance level under all specifications, implying that both price series are integrated of order one, $I(1)$.

Table 6.15 shows that the relationship between Henry Hub and SoCal prices is stationary for the whole sample under all three specifications. The specification in Column (2) is used to test for cointegration at various capacity factors.

Table 6.12 shows these tests for various non-binding levels of capacity. Prices in these non-binding periods are, for the most part, found to be cointegrated. Note that the cointegrating factors are less than one. The link between SoCal prices and Henry Hub prices is not as direct as it is between FGT Zone 3 and Henry Hub prices. California is a producing region as well as consuming. Further complicating the matter is that Southern California imports gas from the Rockies, Western Texas, and the Southwest. Gas does not flow from Henry Hub to Southern California. The prices at Henry Hub are connected to prices in Southern California because the production regions exporting gas to Southern California also export to markets in the midwest and east. The model in equation (3.14), with gas moving from producing to consuming regions, does not describe the relationship between the two prices as it did in Florida. The more standard Law of One Price model (3.14), which allows individual prices to float within the bounds of arbitrage is more applicable. It should not be expected that there is the same relationship consistent with transportation rate contract terms as is the case in Florida.

Tests using only data from days with binding capacity are shown in table 6.13. All the tests using capacity factors greater than 90 percent fail to reject a non-stationary relationship between Henry Hub and SoCal prices at a 5 percent level. This is consistent with capacity constraints causing breakdowns in market integration. The small number of observations used to test cointegration, however, makes this result less convincing than the Florida case.

Table 6.12: California Cointegration Tests - Various Non-Binding Capacity Factors

Capacity Factor VARIABLES	(1) All SoCal Price	(2) <98% SoCal Price	(3) <95% SoCal Price	(4) <92% SoCal Price	(5) <90% SoCal Price	(6) <85% SoCal Price	(7) <80% SoCal Price	(8) <75% SoCal Price
Henry Hub Price	0.885*** (0.006)	0.885*** (0.006)	0.882*** (0.006)	0.873*** (0.007)	0.869*** (0.007)	0.827*** (0.010)	0.828*** (0.011)	0.849*** (0.011)
Constant	0.292*** (0.041)	0.291*** (0.041)	0.303*** (0.041)	0.342*** (0.043)	0.355*** (0.046)	0.586*** (0.057)	0.623*** (0.063)	0.536*** (0.065)
ADF Ctital Stat 1%	-3.43	-3.43	-3.43	-3.43	-3.43	-3.43	-3.452	-3.48
ADF Ctital Stat 5%	-2.86	-2.86	-2.86	-2.86	-2.86	-2.86	-2.876	-2.885
ADF Test Stat	-14.15***	-14.11***	-14.13***	-13.41***	-12.45***	-7.89***	-2.58*	-1.72
ADF P-Value	0.000	0.000	0.000	0.000	0.000	0.000	0.097	0.423
Observations	966	961	927	863	802	588	353	177
R-squared	0.944	0.944	0.942	0.936	0.930	0.901	0.921	0.957

Standard errors in parentheses
 *** p<0.01, ** p<0.05, * p<0.1

Table 6.13: California Cointegration Tests - Various Binding Capacity Factors

Capacity Factors	All	>80%	>85%)	>90%	>92%	>95%	>98%
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	SoCal Price	SoCal Price	SoCal Price	SoCal Price	SoCal Price	SoCal Price	SoCal Price
Henry Hub Price	0.885*** (0.006)	0.906*** (0.008)	0.925*** (0.008)	0.902*** (0.010)	0.913*** (0.013)	0.856*** (0.026)	0.578** (0.077)
Constant	0.292*** (0.041)	0.148*** (0.055)	0.0758 (0.058)	0.396*** (0.083)	0.342*** (0.112)	0.946*** (0.231)	3.160** (0.641)
ADF Ctital Stat 5%	-2.86	-2.87	-2.88	-2.89	-2.95	-3.00	N/A
ADF Test Stat	-14.15***	-10.252***	-8.83***	-2.83*	-1.84	-1.62	N/A
ADF P-Value	0.000	0.000	0.000	.054	0.360	0.474	N/A
Observations	966	495	272	92	44	15	4
R-squared	0.944	0.951	0.973	0.981	0.982	0.973	0.966

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.14: California Unit Root Tests

	No Constant	Constant	Constant/Trend
<u>Critical Values</u>			
10% Significance	-1.62	-2.57	-3.12
5% Significance	-1.95	-2.86	-3.41
1% Significance	-2.58	-3.43	-3.96
<u>Test Stats</u>			
Henry Hub	2.85 (n/a)	-0.017 (0.957)	-1.57 (0.803)
SoCal Price	5.421 (n/a)	-0.957 (0.7687)	-3.953** (0.0102)
Henry Hub Differenced	-20.27*** (n/a)	-20.27*** (0.000)	-20.37*** (0.000)
SoCal Differenced	-39.67*** (n/a)	-38.4*** (0.000)	-37.74*** (0.000)

p-values in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Cointegration on Regional Prices

Cointegration tests between prices at 14 points, forming 182 market pairs, are also run. These tests use the full sample and do not exclude any possible binding capacity days. Table 6.13 shows the results for stationarity tests on all the regional price series. All prices appear to be integrated of order one (I(1)). Engle-Granger cointegration tests are run on all 182 market pairs. All are found to be cointegrated. As has been shown, this does not prove that there are no bottlenecks along the pipeline system between these points. Any bottlenecks, however, are not strong or persistent enough to be spotted by cointegration tests. These results lend support to the claim that the post restructuring wholesale natural gas market has been generally integrated into a single national market.

Table 6.15: California Cointegration Tests - Full Sample

VARIABLES	(1) SoCal Price	(2) SoCal Price	(3) SoCal Price
Henry Hub Price	0.926*** (0.002)	0.885*** (0.006)	0.905*** (0.008)
Time Trend			0.00014*** (3.95e-05)
Constant		0.292*** (0.041)	0.0407 (0.081)
ADF Ctital Stat 1%	-3.43	-3.43	-3.43
ADF Test Stat	-14.581***	-14.149***	-14.143***
Observations	1,227	1,227	1,227
R-squared	0.992	0.944	0.944

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Table 6.16: ADF Tests on Regional Prices

Price Series	Level ADF		Difference ADF	
	Test Stat	P-Value	Test Stat	P-Value
Henry Hub	-0.98	0.7623	-30.05	0.0000
Malin	-1.39	0.5867	-33.19	0.0000
PG&E Citygate	-1.26	0.6494	-34.86	0.0000
SoCal Avg.	-0.88	0.7943	-38.52	0.0000
Katy Hub	-0.92	0.7822	-27.08	0.0000
FGT Zone 3 Citygate	-2.13	0.2332	-19.51	0.0000
Chicago Citygate	-1.42	0.5746	-28.25	0.0000
NE Columbia	-1.46	0.5531	-28.90	0.0000
Kingsgate	-2.02	0.2759	-31.45	0.0000
Kern River	-2.21	0.2024	-38.17	0.0000
Opal Hub	-2.24	0.1928	-37.80	0.0000
Stanfield	-1.60	0.4822	-32.87	0.0000
FGT Zone 3 AL-MS	-1.25	0.6530	-29.22	0.0000
Waha Hub	-0.93	0.7775	-31.04	0.0000

Table 6.17: Cointegration Tests on Regional Prices

Price Series	Henry	Malin	PG&E	SoCal	Katy	F-CG	Chic	Colum	Kings	Kern	Opal	Stan	F-ALMS	Waha
Henry Hub	–	-5.73	-5.76	-14.23	-7.40	-9.94	-14.49	-8.02	-5.25	-5.94	-5.86	-5.50	-7.75	-10.78
Malin	-5.65	–	-10.52	-18.60	-5.03	-9.23	-9.04	-3.96	-11.79	-6.34	-6.27	-10.66	-6.38	-11.17
PG&E Citygate	-5.72	-10.55	–	-17.81	-4.61	-9.11	-8.84	-4.29	-10.20	-6.27	-6.20	-10.48	-6.12	-10.22
SoCal Avg.	-14.69	-19.11	-18.29	–	-16.38	-9.84	-16.08	-13.91	-16.31	-5.44	-5.31	-18.16	-11.71	-8.99
Katy Hub	-7.47	-5.16	-4.70	-16.02	–	-10.31	-10.78	-4.93	-4.30	-6.04	-5.99	-4.93	-7.36	-12.81
FGT Zone 3 Citygate	-9.10	-8.25	-8.08	-8.66	-9.34	–	-9.16	-9.11	-7.98	-5.53	-5.41	-8.10	-9.84	-9.00
Chicago Citygate	-14.45	-9.02	-8.80	-15.61	-10.66	-10.15	–	-12.53	-8.08	-5.94	-5.85	-8.38	-8.86	-11.07
NE Columbia	-7.95	-3.93	-4.23	-13.36	-4.80	-10.00	-12.48	–	-3.44	-5.87	-5.81	-3.74	-7.52	-9.59
Kingsgate	-5.01	-11.74	-10.12	-16.00	-4.05	-8.88	-8.02	-3.34	–	-6.31	-6.23	-18.99	-5.31	-9.70
Kern River	-5.08	-5.52	-5.40	-4.20	-5.05	-6.48	-5.05	-5.01	-5.63	–	-32.65	-5.77	-4.82	-4.35
Opal Hub	-5.02	-5.49	-5.38	-4.09	-5.02	-6.44	-4.98	-5.00	-5.60	-32.68	–	-5.75	-4.81	-4.29
Stanfield	-5.36	-10.62	-10.41	-17.60	-4.73	-9.07	-8.34	-3.70	-19.01	-6.50	-6.44	–	-5.81	-10.76
FGT Zone 3 AL-MS	-7.75	-6.41	-6.12	-11.43	-7.29	-10.74	-8.92	-7.58	-5.54	-5.78	-5.73	-5.90	–	-9.13
Waha	-11.16	-11.53	-10.54	-8.95	-13.14	-10.07	-11.44	-10.04	-9.90	-5.53	-5.44	-11.19	-9.33	–

DISCUSSION

Conclusions and Implications

Pipeline constraints affect regional wholesale gas prices and can do so to a significant degree. Pipeline constraints increased Florida wholesale prices by 2.50\$/MMBtu on average over the October 2006 to August 2011 period. Over the same period, the effect of constraints was a smaller 0.17\$/MMBtu on Southern California prices. The effect of demand shifts is also amplified during binding periods. The ability of transportation infrastructure to ship gas between regions needs to be taken into account when analyzing natural gas markets.

This thesis finds support for earlier research showing that restructuring in wholesale natural gas markets and open access has created arbitrage and integration between regional markets. Prices at 14 market points, forming 182 market pairs, are found to be cointegrated using Engle-Granger tests. The Southern California market appears to be integrated into the larger national market and gas flows into the region are rarely constrained over the sample period. The Law of One Price holds as long as the transportation network can physically support arbitrage between markets. It is shown that as pipeline capacity binds in Florida and Southern California markets, cointegration between regional prices breaks down (implying that market integration breaks down).

Table 7.1 shows data from an EIA study on recent expansions to storage deliverability.¹ Between 2005 and 2010 storage deliverability increased by 23.2 percent for the United States as a whole, and by 16.1 percent for California. Table 7.2 shows that capacity expansions at major natural gas hubs increased by 56.6 percent in the United States between

¹Deliverability is a similar measure to pipeline capacity. Storage capacity refers to the amount of gas that can be stored in a field.

2003 and 2008. These expansions likely led to the strengthening of integration between regional markets in the time since previous studies found weakening links.

With natural gas consumption expected to continue to increase in the future, decisions on whether or not to expand pipeline capacity will significantly affect regional market integration and pricing. Current transportation infrastructure was built to meet the requirements of current market conditions and policies. Proposed policy changes that affect natural gas markets, particularly those that lead to increased gas demand, should be analyzed with an understanding of the effects of pipeline constraints. Such policies might stricter environmental standards that lead to the displacement of coal generation with gas generation. Alternative policies might include changes to the regulatory structure of natural gas markets.

For example, Davis and Muehlegger (2010) have proposed moving away from rate-of-return regulation in retail natural gas markets and towards a two-part tariff. The marginal cost of local distribution companies (LDCs) is their cost of gas, the wholesale price. Under current conditions, residential and commercial customers face price mark ups over 40 percent above marginal costs. A two-part tariff with a fixed component allowing capital recovery plus returns and a variable component charging customers the wholesale price (marginal cost), would lead to a more efficient allocation of natural gas. Their proposal is illustrated in figure 7.1. Prices paid by retail customers would fall from P^{Retail} to $P^{Wholesale}$ and the quantity of gas consumed would increase from Q^0 to Q^1 . Deadweight loss, from the rate-of-return regulation induced price and quantity compared to the socially optimal price and quantity, would decrease by the areas A + B + C. If pipeline capacity is Q^C , however, Q^1 is not a possible outcome. Prices paid by retail customers would only fall to $P^{Constraint}$, and deadweight loss would only decrease by the area A. In order to reach the outcome described by Davis and Muehlegger (2010), pipeline capacity would need to be

expanded by $(Q^1 - Q^C)$. The gain in total welfare would need to account for the costs of pipeline expansion.

Using the elasticity estimates from Davis and Muehlegger (2010), annual natural gas consumption would have been 6.04 percent higher, on average, since 1997.² For some perspective, annual natural gas consumption rose by 5.95 percent from 1997 to 2010. Transportation and storage infrastructure would need to be expanded to support restructuring of retail natural gas markets.

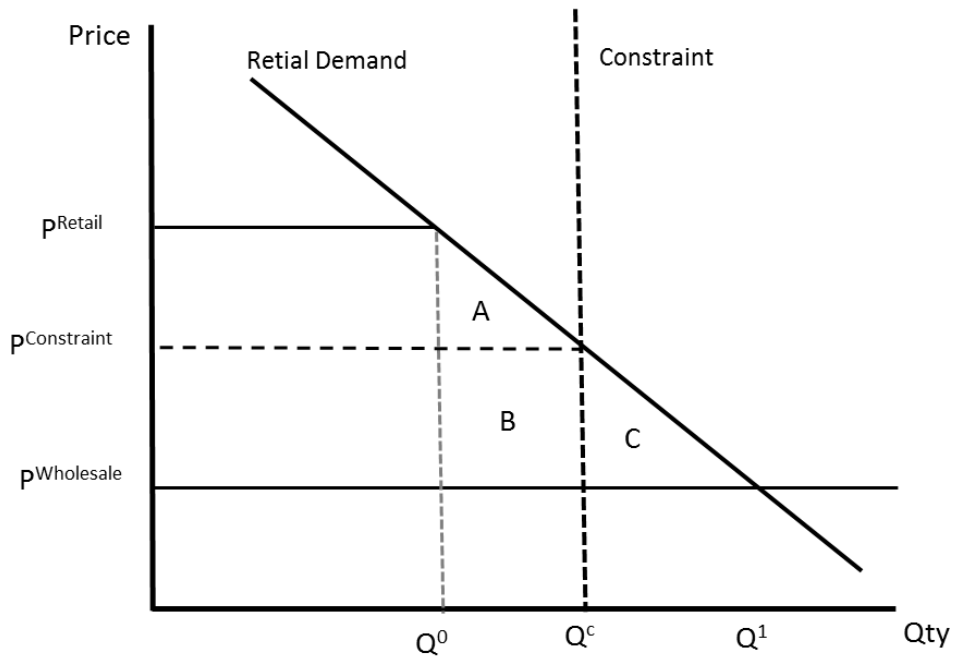


Figure 7.1: Two-Part Tariff in Retail Gas Markets

²The most recent data that separates residential and commercial consumption from total consumption begins in 1997.

Suggested Future Research

The expansion of pipeline and storage capacity affects regional pricing and market integration. Understanding how and when pipeline expansions occur is an important question. How efficiently are gas producers, buyers, marketers and pipeline companies able to contract for pipeline and storage expansion? How does the regulatory process affect infrastructure projects?

It is also unclear who captures the rents of capacity-induced price spikes. How do sellers of gas compete for access to constrained markets? Are pipeline companies able to capture some of this rent? Is it dissipated in regulatory proceedings? How might the ability to capture these rents affect decisions to expand pipeline capacity? How are capital investments affected in regional markets as they become integrated into the national natural gas market? How do transportation contracts differ across constrained and unconstrained regions?

Estimates of the welfare effects from pipeline constraints were not attempted in this thesis. This is because no data were available on the quantity of gas purchased on the daily market, during bid week, or on long-term contracts. Having these estimates would allow for a fuller understanding of the impacts of pipeline constraints on wholesale gas markets.

A more detailed look at capital investment and contracting arrangements in natural gas markets may allow for a fuller understanding of the long term impact of restructuring and open access. It may also help us understand how rapidly growing natural gas production and consumption, driven primarily by technological advancements, will affect natural gas markets in the years to come.

Table 7.1: Storage Deliverability 2005-2010 (MMCFD)

State	2005	2006	2007	2008	2009	2010	% Change
AL	614.4	810.0	900.0	1,600.0	1,600.0	1,600.0	160.4%
AR	230.5	230.5	230.5	230.5	217.5	230.5	0.0%
CA	6,410.0	6,460.0	6,840.0	6,875.0	7,225.0	7,445.0	16.1%
CO	1,088.0	1,088.0	1,088.0	1,088.0	1,268.1	1,273.9	17.1%
IA	1,025.0	1,060.0	1,060.0	1,200.0	1,208.0	1,208.0	17.9%
IL	6,126.1	6,119.1	6,136.0	6,136.0	6,276.0	6,276.0	2.4%
IN	761.5	787.2	784.2	780.7	772.7	767.3	0.8%
KS	2,596.5	2,418.5	2,417.6	2,417.6	2,417.6	2,457.6	-5.3%
KY	1,820.1	1,820.1	1,859.6	1,908.2	1,908.2	2,063.1	13.3%
LA	6,852.2	7,179.7	7,129.7	8,340.2	10,324.7	11,260.7	64.3%
MD	400.0	400.0	400.0	400.0	400.0	400.0	0.0%
MI	14,852.0	14,852.0	16,671.0	17,391.0	17,391.0	17,376.0	17.0%
MN	60.0	60.0	60.0	60.0	60.0	60.0	0.0%
MO	350.0	350.0	350.0	350.0	350.0	350.0	0.0%
MS	4,092.4	4,070.4	4,070.4	5,347.4	5,856.7	8,062.1	97.0%
MT	299.8	309.8	309.8	309.8	309.8	309.8	3.3%
NE	169.0	169.0	169.0	169.0	169.0	179.0	5.9%
NM	378.0	378.0	375.0	350.0	350.0	350.0	-7.4%
NY	1,642.6	1,842.6	1,696.5	1,812.0	2,827.6	2,833.6	72.5%
OH	4,682.3	4,682.3	4,670.4	4,877.1	4,972.8	4,984.4	6.5%
OK	3,566.0	3,637.0	3,772.0	3,747.0	3,793.5	3,859.5	8.2%
OR	340.5	435.0	495.0	515.0	515.0	515.0	51.2%
PA	8,484.6	8,638.0	8,128.3	8,572.2	9,508.8	9,487.9	11.8%
TN	20.0	20.0	20.0	20.0	20.0	20.0	0.0%
TX	11,373.0	11,815.4	10,806.3	12,951.7	13,443.4	13,764.0	21.0%
UT	527.0	527.0	527.0	527.0	527.0	865.0	64.1%
VA	347.0	347.0	345.0	325.0	345.0	345.0	-0.6%
WA	850.0	850.0	850.0	1,150.0	1,150.0	1,150.0	35.3%
WV	3,795.6	3,895.6	4,002.4	3,838.5	3,810.7	3,793.4	-0.1%
WY	301.7	301.7	301.6	301.6	301.6	298.5	-1.1%
Total U.S.	84,055.7	85,553.7	86,465.1	93,590.4	99,319.5	103,585.1	23.2%

Table 7.2: Expansions of Major Natural Gas Hub Capacity 2003-2008 (MMCFD)

Hub	2003	2008	% Change
Louisiana Perryville Center	2,351	11,800	401.9%
Louisiana Egan Hub	1,650	4,545	175.5%
Colorado Cheyenne Hub	2,854	6,396	124.1%
Wyoming Opal Hub	3,250	6,038	85.8%
East Texas Moss Bluff Hub	1,425	2,425	70.2%
Louisiana Henry Hub	2,470	3,670	48.6%
California Energy Hub	4,600	6,784	47.5%
Pennsylvania Dominion Hub	5,893	8,348	41.7%
Illinois ANR Joliet Hub	3,900	5,390	38.2%
California Golden Gate Center	4,545	6,017	32.4%
New Mexico Blanco Hub	3,455	4,200	21.6%
West Texas Waha (DCP/Atmos) Hub	1,950	2,330	19.5%
Oregon GTNW Market Center	5,675	6,380	12.4%
Louisiana Jefferson Island Hub	2,045	2,295	12.2%
East Texas Carthage Hub	1,520	1,700	11.8%
East Texas Aqua Dulce Hub	1,528	1,690	10.6%
Illinois Chicago Hub	2,175	2,375	9.2%
New York Iroquois Center	1,950	2,050	5.1%
East Texas Katy Storage Center	2,580	2,615	1.4%
East Texas Katy (DCP) Hub	1,430	1,430	0.0%
Louisiana Nautilus Hub	2,519	2,519	0.0%
West Texas Waha (EPGT) Texas Hub	1,825	1,825	0.0%
Kansas Mid-Continent Center	1,275	735	-42.4%
Colorado White River Hub	–	4,905	N/A
Total	62,865	98,462	56.6%

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APPENDICES

APPENDIX A

ABBREVIATIONS AND TERMS

Abbreviations

ADF	Augmented Dickey-Fuller stationarity test
CDD	Cooling Degree Days
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission
HDD	Heating Degree Days
HHI	Herfindahl-Hirschman Index
IOU	Investor Owned Utility
LDC	Local (gas) Distribution Company
Mcf	Thousand cubic feet at 14.7 PSI
MFN	Most-Favored Nation clause
MMBtu	Million British thermal units
MUD	Municipal Utility District
NEMS	National Energy Modeling System
NGA	Natural Gas Act of 1938
NOAA	National Oceanic and Atmospheric Administration
NYMEX	New York Merchantile Exchange
Tcf	Trillion cubic feet at 14.7 PSI
WTI	West Texas Intermediate Crude Oil at Cushing, OK

Action	Year	Effect
PUHC Act	1935	Public Utilities Holding Company Act split local distribution from long distance transportation
Natural Gas Act	1938	Regulatory oversight of interstate pipelines given to Federal Power Commission (now FERC)
Phillips Decisions	1954	Regulation of natural gas wellhead prices
Special Marketing Programs	1983	Allowed sellers and buyers to trade directly, only using pipelines for transportation services
FERC Orders 436	1985	Allowed interstate pipelines to voluntarily declare themselves open access
FERC Order 500	1987	Commodity and transport services separated
FERC Order 636	1992	Interstate pipelines must be open access

APPENDIX B

FERC RATE SETTING

FERC uses a cost-of-service method for setting “just and reasonable” interstate transportation rates (or tariffs). The costs of providing transportation services and a “reasonable” rate of return are determined and rates are set to recover this amount. A pipeline may file for a change in rates under Section 4 of the Natural Gas Act of 1938 (NGA). A “general” Section 4 filing reviews rates for all services offered by the pipeline, while a “limited” Section 4 filing reviews rates for new services (FERC, 1999). Most rates cases are initiated under Section 4, however, under Section 5 of the NGA, FERC can initiate rate reviews of its own accord or in response to a complaint. In both cases the party wishing to initiate a rate change bears the burden of proof that the rates are no longer “just and reasonable” (Littlechild, 2011).

Under Section 7(c) of the NGA, a pipeline company files for a “Certificate of Public Convenience and Necessity” to construct or expand a pipeline. FERC sets an initial rate (assuming the construction is approved). These rates stay in effect until a general Section 4 or 5 filing when all rates (including those on previously offered services) are reviewed. Under Section 311 of the NGA, intrastate pipelines can transport gas for interstate pipelines or local distribution companies engaged in interstate commerce without being subject to FERC jurisdiction. These intrastate pipelines can select to either use rates set under FERC’s “cost-of-service” methodology or a rate set by the relevant state regulator (FERC, 1999).

Cost-of-service ratemaking can be divided into five basic components. The information in the following list is taken from FERC (1999) and EIA (1995).

1. Establishing Cost-of-service / Revenue Requirement

The cost of service, or revenue requirement, is calculated as follows:

$$\begin{aligned}
 & (\text{Rate Base}) * (\text{Rate of Return}) \\
 & + \text{Operations and Maintenance Expenses} \\
 & + \text{Administrative and General Expenses} \\
 & + \text{Depreciation Expense} \\
 & + \text{Non-Income Taxes} \\
 & + \text{Income Taxes} \\
 & - \text{Non-Income Taxes} \\
 & = \text{Total Cost-of-Service / Revenue Requirement}
 \end{aligned}
 \tag{B.1}$$

The rate base is the total capital investment in the project. The rate of return is determined by the capitalization ratio, the cost of debt, and the allowed rate of return (to be in line with other natural gas company returns).

2. Functionalizing the Cost-of-Service

All costs of service must be assigned to the functional area for which the costs were incurred, either the transmission or storage area.¹

3. Cost Classification

Functionalized costs are classified as either fixed or variable. Fixed costs are those that do not vary with the volume of gas transported. Variable costs change with the

¹Prior to FERC order 636, production was also a functional area including costs of gas produced or purchased.

volume of gas transported. Prior to FERC Order 636 variable costs were mainly the costs of purchased gas. Now that gas sales and transportation services have been unbundled, variable costs are primarily the fuel burned to run the compressors that move gas along the pipeline. Many pipelines cover this fuel cost by retaining a portion of the gas shipped in lieu of charging a dollar amount. Fixed and variable costs are then classified as either reservation or usage charges.² Variable costs are assigned as usage costs. Fixed costs are assigned as reservation costs.³

4. Cost Allocation

Usage costs are allocated to customers based on the volume of gas shipped. Reservation costs are usually allocated by customer capacity-mile requirements.⁴ Allocation factors are used to assign costs among firm, interruptible, and other services. Peak-load usage may also affect the allocation of reservation costs among customers. Expanding capacity to meet peak needs increases capital expenditures, and the increased costs are assigned to peak users.

5. Rate Design

Rate design turns the allocation of costs among different shippers into unit rates. Firm service rates include a reservation charge, per unit of firm capacity contracted, and a volumetric charge, per unit shipped. Interruptible service rates are volumetric charges only. Interruptible rates are usually set as what the average cost per MMBtu shipped would be under a firm rate if 100% of the contracted capacity were used (that is, the lowest per unit rate possible for a firm customer). Usage charges on interruptible service are therefore higher than usage charges for firm service, but the

²These are often referred to as demand and commodity costs, a vestige of the bundled service days.

³This has been true since 1992

⁴Often the pipeline system is broken into zones and transportation rates set for shipping gas between zones (zonal pricing).

reservation charge makes the average charge per unit shipped higher for firm than the average charge for interruptible.⁵ FERC also allows pipelines to offer discounts between maximum and minimum rates. This allows the pipeline leeway in retaining customers (and maintaining load usage). This allows the cost to be spread over more units of gas, lowering the average costs per unit shipped for all customers.

⁵Unless the firm shipper uses 100% of contracted capacity, in which case the average charge per unit shipped would be the same