CAUSE NO. 153-237052-09

PAZ ENERGY LLC,	§	IN THE DISTRICT COURT
	§	
Plaintiff,	§	
	§	
VS.	§	
	§	
DALLAS/FORT WORTH	§	
INTERNATIONAL AIRPORT BOARD,	§	
CITY OF FORT WORTH,	§	
CITY OF DALLAS, CHESAPEAKE	§	153RD JUDICIAL DISTRICT
EXPLORATION, L.L.C., LADA	§	
INVESTMENTS, LLC, CALLEJO	§	
ENERGY L.L.C, FIRST PRESTON	§	
INVESTMENTS, L.L.C., FORTY-FOUR	§	
ENERGY, LP, ICC ENERGY	§	
CORPORATION, MARGOLF, INC.,	§	
SLNJG INVESTMENTS, LLC,	§	
S.B.DIKE, LTD.,	§	
	§	
Defendants.	§	TARRANT COUNTY, TEXAS

Expert Report of

Samuel A. Van Vactor, Ph.D.

November 11, 2011

1. Credentials

My name is Samuel A. Van Vactor. I am an economist, specializing in energy economics since joining the U.S. Treasury in 1973. At the Treasury I analyzed energy issues, particularly the oil market, and two years later I was selected for a position at the newly formed International Energy Agency (IEA) of the Organization for Economic Cooperation and Development (OECD), where I served for three years. Since then, I have held an academic position at Portland State University and founded a consulting and publishing firm, Economic Insight, Inc. (EII). When time allows, I enjoy academic work and will be teaching a course in energy economics at the University of Oregon, Spring Term 2012. I have a B.S. and M.A. in economics from the University of Oregon and the University of Washington in the U.S. and a Ph.D. from Cambridge University in the U.K. My curriculum vitae (CV) is attached as Exhibit A.

I have authored or coauthored a large number of books and articles on the oil and gas industries, which are listed in my CV. My latest book, published by PennWell, is entitled *An Introduction to the Global Oil & Gas Business.*

In the 1980s I was Vice President of Arlon R. Tussing and Associates (ARTA). During this period Dr. Tussing's firm worked extensively on the deregulation of the natural gas industry. In the 1990s I was an expert witness for the Alaska oil producers in their dispute with the State of Alaska over the valuation of North Slope crude oil for royalty and tax purposes. In 2002, I prepared expert reports and testified for Coral (Shell Oil) and Williams concerning their electricity and gas price dispute with the State of California at the Federal Energy Regulatory Commission (FERC). Around the same time, I also prepared reports for BP and Conoco on their contractual obligations as gas suppliers to Bethlehem Steel in bankruptcy hearings and for Sempra concerning the abrogation of a gas supply contract in California by Exxon during the California energy crisis. More recently, I was an expert for the Los Angeles Department of Water and Power (LADWP), the Sacramento

Municipal Utility District (SMUD), and other public and private entities in an antitrust dispute concerning natural gas prices in California. The case settled in late 2008.

In addition to my domestic activities, I have completed a number of reports on the international gas industry, including studies on natural gas development in Southern Africa for Sasol, planning for Northeast Asian natural gas pipelines for the Mitsubishi Research Institute, the development of a natural gas grid in Asia for an Asia Pacific Economic Cooperation (APEC) ministerial meeting, risk management practices for Tokyo Gas, and North Sea contract pricing for Gaz de France. I have lectured on oil and natural gas markets in Singapore and Kuala Lumpur and at a variety of universities.

2. Purpose of this Report

Officials from the Dallas Fort Worth Airport ("DFW") asked me to review documents, reports, invoices and analyses produced in this matter and prepare a report. The review included: documents and other background material from DFW, the lessor, and Chesapeake Exploration, LLC ("Chesapeake'), producer and lessee; Federal Energy Regulatory Commission (FERC) filings, Energy Information Administration (EIA) data on the natural gas market; trade press publications; information on the Dallas-Fort Worth natural gas market; data and publications from the Texas Railroad Commission ("RRC"); documents produced by Chesapeake and DFW; and discussion with other experts. I was asked to render an opinion on the validity of DFW's claim and compute damages, resulting from the alleged under-pricing of Chesapeake's royalty obligation. I was also instructed to keep data and documents from this case confidential, and have done so.

This report is organized as follows: In Section 3, I briefly review the key characteristics of gas production from the Newark East (Barnett Shale) field ("Barnett field") and royalty-related elements of the DFW-Chesapeake Lease. In Section 4, I discuss the quality characteristics of natural gas and how to determine the comparability of various gas flows. Section 5 discusses the way in which natural gas is sold and analyzes various sources of natural gas price information, explaining why it is common to find a range of market prices, especially in a period of rapid market change. In Section 6, I describe how Chesapeake markets DFW gas. In Section 7, I review alternative marketing strategies, both the local market and shipments for interstate commerce. In Section 8, I discuss DFW's survey of public entities' royalty proceeds and analyze the results. In Section 9, I compare methodologies for determing the "highest market price paid for gas of comparable quality for the field where produced and run" and compile an estimate of the level of Chesapeake's underpayment associated with each methodology.

3. The Barnett Gas Field and the DFW Lease

3.1 Size and Complexity of the Field

The size and complexity of the Barnett field is covered by other witnesses, so only a brief summary appears here. The field is the largest producing gas field in the U.S. and in 2010 it produced 1.8 Tcf; 8.1% of marketed U.S. production. The Barnett field is considered the birthplace of the shale gas industry, where much of the technology was developed. Chesapeake is the second largest operator in the field, producing about 22% of the total.

The Barnett field covers 23 counties and approximately 5,000 square miles; it has pipeline connections to a variety of market centers for interstate commerce and to the local Dallas-Fort Worth market. Production quality varies substantially, with deposits of "rich" or "wet" gas in the western portion that are laced with natural gas liquids ("NGLs") and "lean" or "dry" gas in the east with little or no NGLs and consequently lower thermal content (measured as British thermal units or "Btus").[1] Despite the variability, however, the bulk of the gas produced is considered dry gas and is marketed through intra- and interstate pipelines.

3.2 The DFW Lease

The DFW Lease is large, as such leases go, but production is small relative to the total size of the Barnett field. As of 2009 there were 93 producing wells on the Lease, with output of up to 70,000 thousand cubic feet (mcf) per day and total production in 2008 of 19.7 billion cubic feet (Bcf). The RRC reported that the Barnett shale gas field produced 1,563 Bcf that year, making DFW's share around 1.3%.

Although there are a number of issues in the DFW-Chesapeake dispute, this report concerns the appropriate method to determine royalty payments. Chesapeake's royalty obligation of 25% is based on the higher of total proceeds received by the Lessee or "the highest market price paid for gas of comparable quality for the field where produced and run" (Chesapeake-DFW Lease, paragraph 4(b)). The dispute arises because the royalty payments Chesapeake made were based on the average monthly proceeds received from the buyer, Louis Dreyfus Energy Services ("Dreyfus"), without respect to prices paid to other producers in the Barnett field or higher than monthly average prices paid by Dreyfus to Chesapeake in particular daily or monthly sales. Data from an independent survey conducted by DFW of royalty proceeds from other public entity lessors, data provided by Chesapeake Operating Inc. ("COI") summarizing revenue receipts from properties in the Barnett District (CHK00016487 through 17676,) and Chesapeake-Dreyfus daily and monthly contract price and volume confirmations ("confirms") (CHK1245 though CHK16422)

[1] Methane is the principal component of natural gas and has a Btu content of about 1,000 per cubic foot. The five major NGLs in natural gas are ethane, butane, isobutane, propane and natural gasoline, all of which have higher Btu contents.

reveal a wide range of monthly field prices, many of which were used by Chesapeake for royalty payments.

3.3 Pipeline Connection

The primary marketing outlet for the Barnett field has been through the Atmos pipeline system. The entire Atmos pipeline is within Texas, which means that regulatory authority is the RRC, rather than FERC. The RRC is considered a "light-handed" regulator, in that intrastate pipelines are given considerable scope to negotiate rates with shippers and a single rate for a section of pipeline does not necessarily prevail. The pipeline system is mapped in Appendix B, from the Atmos web site.

Although Atmos is the primary gathering and distribution line in the Dallas-Fort Worth area, it is not the only shipping alternative. For example, Energy Transfer completed an expansion of its capacity from the Barnett field to the Carthage Hub in 2007.

4. Natural Gas Comparability Issues

4.1 Key Determinants of Market Prices and Data Sources

The DFW Lease in Paragraph 4(b) is specific about the determination of the highest market price paid: "gas of <u>comparable quality</u> for the field where produced and run." (Empahsis added). In the case of the DFW Lease, the principal, if not the only, quality issue concerns the Btu content of the gas mainly because it is on the lean end of pipeline quality gas. Other than that, the gas requires minimal processing before transmission and, in any case, the Lessor's royalty is not to bear such costs, even indirectly (see Paragraph 4(c)). An abstract discussion about comparable gas sales is not, however, dispositive. Commodity markets are diverse and complex, and Barnett shale gas is no exception. The sheer size and diversity of the field can actually be helpful in settling the various issues, because it provides a robust dataset for analysis. Does the Btu content of the gas or its sales volume cause prices to differ?

4.2 Impact of Btu Content on Natural Gas Values

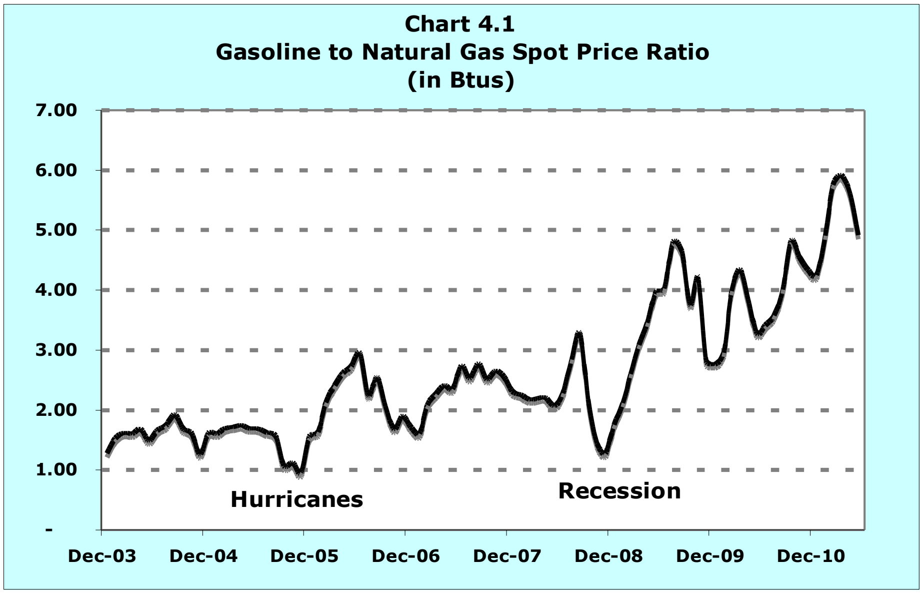
At the wellhead, natural gas quality varies. Most of the variability is identified by a single measure: the Btu content of the gas. Btu content can vary, because the gas may contain a greater proportion of NGLs than simple methane or, on the downside, because the gas contains nitrogen or other gases with little or no thermal value. Natural gas may also contain contaminants, such as sulfur, which are corrosive and must be removed. In order to deliver the gas to a commercial pipeline, producers usually send it to a processing unit where NGL's are stripped and contaminants removed so the gas meets pipeline standards. Various natural gas streams can also be blended to adjust Btu levels. For example, many Liquefied Natural Gas (LNG) cargoes have a high Btu content (Persian Gulf LNG is usually higher than 1,130 Btu per cubic foot). In order to be delivered to an onshore pipeline, that gas has to be stripped of NGLs or blended with low Btu gas. Likewise, rich domestic natural gas must be stripped or blended in order to meet pipeline specifications. Producers make processing and blending choices based on the relative values of rich and lean gas and the various compounds they contain.

4.3 Variability in the Value of NGLs

Relative market values of wet and dry gas have varied significantly over the last decade. NGLs can be processed by refiners to extend gasoline or other liquid fuel production. Thus, as oil prices rise relative to natural gas prices, NGL's become more valuable and wet gas rises in value as compared to dry gas; this is particularly the case in the present market (2011) where thermal values of petroleum products are at historic highs as compared to natural gas. This has led buyers to pay a premium for wet gas in order to obtain the NGLs.

However, the reverse can happen, too. Natural gas prices rose sharply relative to oil prices after hurricanes Katrina and Rita hammered the Gulf Coast in the summer of 2005. In response to high natural gas prices, relative to oil, many NGL's were left in the gas. As a consequence, liquids collected in some pipelines, interfering with transmission. Referring to this problem at the time the EIA noted: "producers have tended, for economic reasons, to increase the Btu content into the pipeline grid while decreasing the amount of natural gas liquids extracted from the natural gas stream." (EIA Gas Processing).

Chart 4.1 plots the ratio of gasoline prices to natural gas prices. The first step in calculating this chart is to convert gasoline prices from dollars per gallon to dollars per million Btu. (There is about 125 thousand Btu in a gallon of conventional gasoline.) Then, gasoline prices are divided by natural gas prices to create a ratio. The higher the ratio between gasoline and natural gas prices, the greater the incentive to divert NGL's to refiners for upgrading to gasoline or other petroleum products.



When the ratio is low, then gas producers have an incentive to increase the Btu content of natural gas delivered to pipelines by retaining NGLs in the stream.

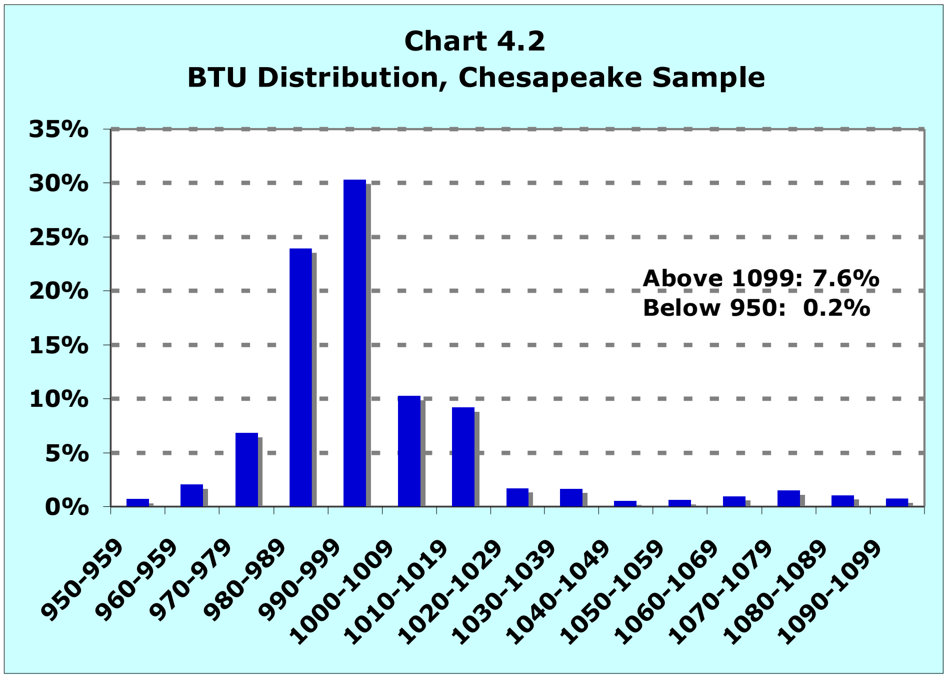
4.4 Pipeline Specifications for Gas Deliverability

Change in the relative value of wet and dry gas should not be confused with the valuation of dry natural gas where Btu content varies, but remains within conventional pipeline standards. While Btu and NGL content of natural gas correlate, they do not do so perfectly across wells or over time. Two wells may produce gas with the same Btu's but different concentrations of NGLs, and vice-versa. According to the EIA, most pipeline standards fall within the range 985 to 1,085 Btu per cubic foot (EIA Gas Processing). Pipeline specifications on the Atmos pipeline system, the primary line for shipping DFW gas, range from 950 to 1,100 Btu per cubic foot (Atmos Interconnection). As noted, producers can meet pipeline standards by blending various gas sources, or in processing raw gas they can strip liquids, reducing the Btu content. They could also add denser hydrocarbons to increase the Btu content.

Since pipeline gas is priced on its Btu content, higher Btu gas generally receives a higher price. However, under certain conditions low Btu pipeline gas may garner a modest premium, i.e., its price <u>per Btu</u> can be slightly higher than for gas delivered to pipelines at the upper end of the Btu scale. When an abundance of rich gas brings Btu content in a pipeline close to its upper limit, lean gas, as a counterweight, becomes more valuable. As noted, during multiple periods between 2004 and 2008 many producers left NGLs in the gas stream, at times exceeding the upper limit of pipeline specifications. In these circumstances low-Btu gas could be blended with the wet gas. This low-cost alternative to stripping the gas enhanced the demand for low-Btu gas and pumped up its relative price. It is worth noting that while gas from the DFW lease is towards the lean end of the pipeline range, it meets relevant pipeline standards, and it is suitable for blending with rich gas when there is an economic incentive to do so.

4.5 Distribution of Barnett Gas Btus

An obvious concern when analyzing the comparability of gas produced from the Barnett field is the proportion and location of wet and dry gas. The field's distribution can be checked using data provided by Chesapeake from leases in which it had a working interest (CHK 16487 to 17676) or using the public entity royalty data. The Chesapeake data alone provide a substantial sample, representing about one-fifth of the Barnett field's production during this time period. Chart 4.2 illustrates the breakdown based on 10-unit segments of Btu values.



Over half of the gas produced had a Btu value between 980 and 999 per cubic foot, and over 92% of the gas had a Btu value less than 1,100. This suggests that the amount of NGL laden gas in the field is less than 10%. Also, as mentioned, it is commonly understood that the wet gas deposits are in the western segment of the field, far from the DFW lease.

4.6 Evidence of Discounts or Premiums for Low Btu Gas.

Table 4.1: Statistical Significance of Correlations Between Prices and BTU's

	Correlation with BTU (IF KNOWN)	Observations	Statistically > 0 at 90% Level?	Statistically > 0 at 99% Level?
		Difference from NYMEX		
All	0.286	985	Yes	Yes
< 950	0.378	4	No	No
950-1049	(0.025)	631	No	No
950-1100	(0.107)	645	No	No
> 1100	0.342	336	Yes	Yes
		Price/MMBtu		
All	0.300	985	Yes	Yes
< 950	0.378	4	No	No
950-1049	(0.057)	631	No	No
950-1100	0.039	645	No	No
> 1100	0.247	336	Yes	Yes

Chesapeake has claimed that gas from the DFW lease was discounted due to its low Btu content. This observation is correct in the right context. That is, in dollars per mcf, low Btu gas generally has a lower price. And, as explained, wet gas saturated with NGL's often commands higher prices in dollars per Btu.

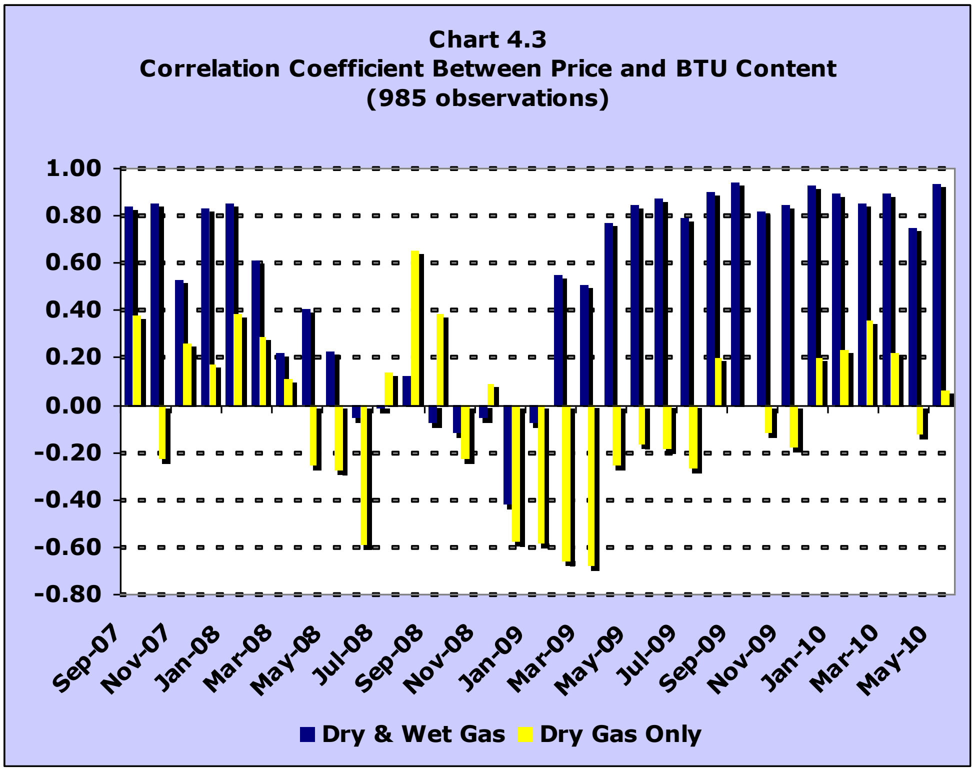
The Btu-price comparability of gas produced from various parts of the Barnett field can be checked using the data provided by Chesapeake. To do so, I sorted the September 2007 through May 2010 data removing observations that 1) had no Btu data and 2) included either Chesapeake Energy Marketing Incorporated ("CEMI") or "Total" (which purchased CEMI interests) as the "Revenue Remitter." I was left with 985 observations over a period of 33 months. I then subtracted the NYMEX average bidweek price for the prompt month to produce an index for individual transactions adjusted for overall market conditions. On average, Chesapeake's claimed remittances for its Barnett interests were $1.44 per MMBtu below NYMEX prices (in dollars per MMBtu).[2] Table 4.1 shows correlations and their statistical significance of this index and price per MMBtu with Btu content.

The correlation coefficient between the market-adjusted index and the Btu content of gas produced was 0.286. In other words, over the 33 month period there was a tendency for low-Btu gas to receive a lower price, relative to the NYMEX price, per Btu, than high-Btu gas, when considering both dry and wet gas as one group. The same procedure can be used excluding gas with Btus outside the range 950 to 1049 and the range of 950 to 1100 per cf. In the first group there are 631 observations and on average values were $1.54 below NYMEX prices. The correlation coefficient was, however, different at -0.025. This is not statistically significantly greater than zero, and it indicates little or no relationship between the level of Btus and the value per Btu. I performed a similar analysis on the 950 to 1100 group (gas that meets Atmos pipeline standards). For that group, the average discount was $1.55, and the correlation coefficient was -0.107 which is not statistically significantly greater than zero. If I do not subtract the NYMEX price, the correlations between value per MMBtu and Btu content for the two groups of dry gas are -0.057 and -0.039, respectively, neither of which is statistically significantly less than zero.

Chesapeake's data can also be used to demonstrate how the economics of the marketplace impact relative values of dry and wet gas. Chart 4.3 reinforces the idea that it is the presence of Btu-rich NGLs, rather than Btu content per se, that explains any positive relationship between Btu content and price. The correlation between Btu content and the price for wet and dry gas together is positive and large over the 32-month period, except during the upward shock to oil prices in the spring and summer of 2008 and its aftermath, presumably because producers left NGLs in the stream. In contrast, the relationship between price and Btu content of dry gas is more randomly distributed across both positive

[2] As will be explained later, these reimbursements appear to include processing, tax, and other deductions, and do not represent the actual prices at which the gas was sold. They should, however, capture relative values, which are the basis for this analysis.

and negative values during this time period, and the positive values it assumes are much smaller than those attained when wet gas is included.



4.7 Sales Volume Impact

Chesapeake may assert that to make large-volume sales, prices had to be discounted. Suppose that were true. Why would Chesapeake not choose several low-volume sales at higher prices? If the reason were to reduce the cost of marketing the gas, the choice of higher volumes should not affect Chesapeake's royalty obligation. Paragraph 4(c) of the Lease states that the "Lessor's royalty shall never bear, either directly or indirectly, any part of the costs of … marketing of the oil or gas…", so prices for small volume sales should be considered comparable inasmuch as large volumes were chosen to reduce marketing costs.

Table 4.2: Statistical Significance of Correlations Between Prices and Volumes

	Correlation with BTU (IF KNOWN)	Observations	Statistically < 0 at 90% Level?	Statistically < 0 at 99% Level?
	Difference from NYMEX			
All	-0.009	645	No	No
<100	1.000	2		
< 1000	-0.702	12	Yes	Yes
< 10000	-0.065	171	No	No
1,000 - 99,999	-0.001	437	No	No
	Price/MMBtu			
All	0.013	645	No	No
<100	1.000	2		
< 1000	-0.155	12	No	No
< 10000	-0.141	171	Yes	No
1,000 - 99,999	0.019	437	No	No

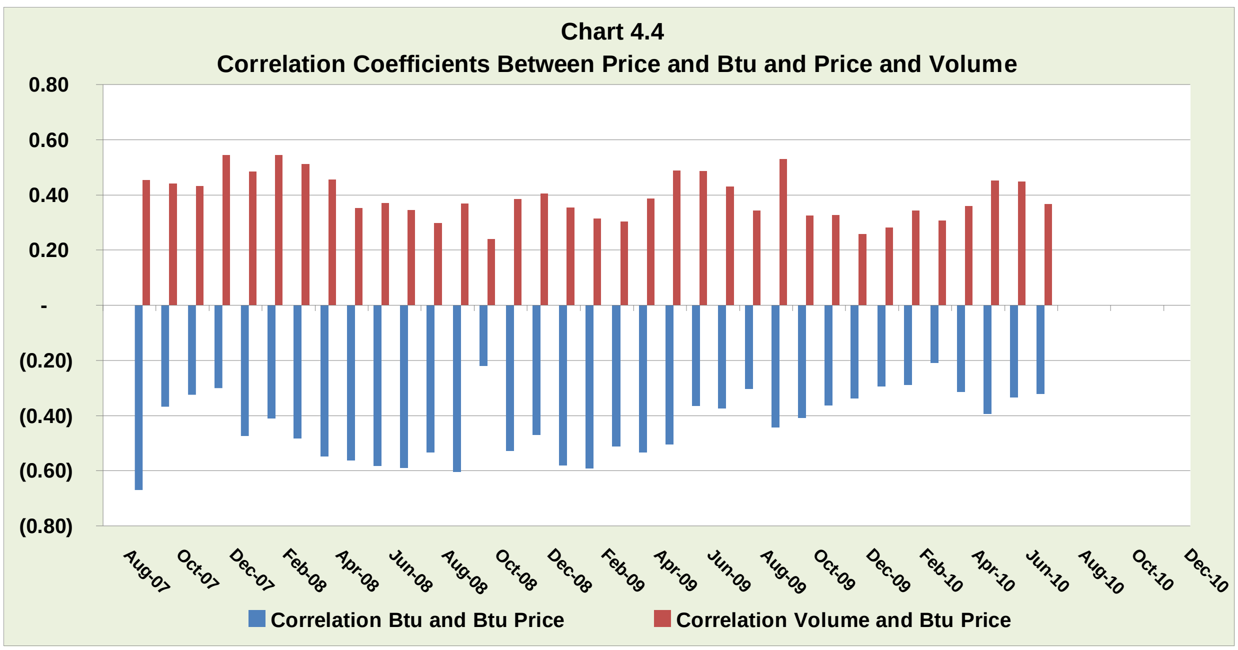
Moreover, there is no evidence that sales volume impacts price in the relevant range for dry gas.[3] Unlike some commodities, gas is moved through pipelines and per-unit transportation costs are virtually the same for large or small lots. If anything, it would be expected that small volume sales would have a lower price because the per-unit transaction cost of deal-making would be higher.

Once again Chesapeake's data on working interest remittances and public entity royalty data allow this assertion to be tested. The first step in this analysis is to remove observations where the Btu values of the gas were below 950 or above 1100 per cubic foot. I was left with 645 observations. The correlation between volume and price was not significantly less than zero when volume was measured against price differences from NYMEX or against prices themselves. For small volume sales, there was a negative correlation between the difference from NYMEX price and volume, but the relationship disappears when looking at all sales between 1,000 and 99,999 mcf.

[3] Obviously, low volume market extremes (below 1,000 MCF per month) and a variety of other types of transactions do not qualify as market values. Examples of transactions that should not be considered include accounting adjustments, trades to effect transportation, affiliate transfers, etc.

4.8 Public Entity Data

A similar analysis of the impact of Btu and volume on price per Btu was conducted on data DFW collected from other royalty recipients in Denton, Johnson, Tarrant, and Wise counties. (The sources of these data and how they were analyzed are discussed more fully in Section 8 of this report).



The relationships in these data are more pronounced than those produced by Chesapeake. There is a clear negative relationship between the Btu content of a natural gas sale and its price. Within the range 950 to 1,100 Btu per cubic foot, gas with lower Btu content tends to receive a higher price when priced in dollars per Btu. In mirror image, high volume contracts tend to receive somewhat higher prices than low volume contracts. The month-to-month variation in correlation coefficients is summarized in Table 4.3 and illustrated in Chart 4.4.

Table 4.3
Correlation Coefficients from Public Entity Royalty Data

Date	Correlation Btu and Btu Price	Correlation Volume and Btu Price
Sep-07	(0.67)	0.45
Oct-07	(0.37)	0.44
Nov-07	(0.32)	0.43
Dec-07	(0.30)	0.54
Jan-08	(0.47)	0.48
Feb-08	(0.41)	0.54
Mar-08	(0.48)	0.51
Apr-08	(0.55)	0.46
May-08	(0.56)	0.35
Jun-08	(0.58)	0.37
Jul-08	(0.59)	0.35
Aug-08	(0.53)	0.30
Sep-08	(0.60)	0.37
Oct-08	(0.22)	0.24
Nov-08	(0.53)	0.39
Dec-08	(0.47)	0.41
Jan-09	(0.58)	0.36
Feb-09	(0.59)	0.31
Mar-09	(0.51)	0.30
Apr-09	(0.53)	0.39
May-09	(0.50)	0.49
Jun-09	(0.36)	0.49
Jul-09	(0.37)	0.43
Aug-09	(0.30)	0.34
Sep-09	(0.44)	0.53
Oct-09	(0.41)	0.32
Nov-09	(0.36)	0.33
Dec-09	(0.34)	0.26
Jan-10	(0.29)	0.28
Feb-10	(0.29)	0.34
Mar-10	(0.21)	0.31
Apr-10	(0.31)	0.36
May-10	(0.40)	0.45
Jun-10	(0.34)	0.45
Jul-10	(0.32)	0.37

The different results in the two data sets might be explained by greater variation in Btu values in the Chesapeake data and/or distortions caused by allowed deductions taken by field operators that result in price (value) distortions. An aggressive calculation of the "highest price in the field," could include premiums for DFW gas because of its relatively low Btu value and large sales volume. Nonetheless, in my view, the data remain inconclusive. This is mainly because a large number of the price data are repetitive. That is, field operators combined gas from multiple wells (or multiple leases) and sold them as one package; thus, a single price may often be repeated in the data. This could distort the degrees of freedom and skew any conclusion based on a narrow statistical analysis. Importantly, however, I discovered no evidence to suggest that low Btu gas should be discounted relative to high Btu gas, as long as the gas is within pipeline standards. Likewise, I found no evidence to suggest that high volume sales resulted in price discounts.

4.9 Conclusion Regarding what Qualifies as "Comparable"

I conclude that for the purpose of determining the highest price in the "field where produced and run," any natural gas sales from the Barnett field, other than those of very small volumes, that meet Atmos pipeline standards (from 950 to 1100 Btu per cf) are of "comparable quality" to DFW production.

5. Gas Marketing

5.1 Common Marketing Procedures

The North American natural gas market transitioned to a commodity market during the 1990s. To a large extent the development mimicked the transition made a decade earlier by crude oil and petroleum product markets. There are, however, some distinct differences. The most obvious is the inflexible infrastructure required to deliver gas. Oil can be moved economically in a wide variety of pipelines, marine tankers, trains, trucks, etc. Natural gas is most economically transported in pipelines, which are usually "natural monopolies". In the 1990s, FERC was able to deregulate the gas market due to two major breakthroughs. First, high prices a decade earlier resulted in surplus pipeline capacity, significantly reducing the market power of pipeline companies. Second, and most important, regulators recognized that the industry could be "unbundled;" that is, the regulation of pipelines could be separate from regulation of the commodity. In a nutshell, FERC could set pipeline transport rates and let competition set natural gas prices.

Competitive gas pricing, however, meant far greater price volatility. The volatility, in turn, created a demand for price hedging, which allowed NYMEX to establish a natural gas futures contract, based at Henry Hub, Louisiana. Over time, physical gas markets evolved in parallel fashion with the NYMEX financial contract. Today's North American gas market has a universal approach from California to New England and from Calgary to Houston. Most natural gas is sold as month-long deliveries. The daily volume and price are fixed through the whole month. Prices are negotiated in the last five business days of the previous month, or the parties choose to index prices to those published by the trade press. Month-long sales in the physical market parallel NYMEX financial trading for gas delivered in what traders refer to as the "prompt" month.

For individual companies gas production seldom matches forecast rates. Variations in weather and multiple technical factors intervene to cause production to swing up and down. Pipelines accommodate some storage, but the companies also penalize shippers if they are over or under their scheduled deliveries. To keep in balance most gas producers sell about three-quarters of expected production into the month-ahead market. Remaining actual production is then sold daily.

While the month-ahead, day-ahead paradigm is the most common method of gas marketing, it is not the only way gas is sold. Buyers or sellers can lock in prices for much longer time periods if they choose to do so. Long-term contracts are available directly from some suppliers that set prices for multiple months. Alternatively, suppliers can agree to sell a given volume of gas over the long term, indexed to prices determined in public exchanges or published by the trade press. Then, if either the buyer or the supplier wishes to, they can hedge prices using financial contracts, such as NYMEX futures or over-the-counter (OTC) derivatives.

The North American gas marketing structure depends heavily on trade press price reporting. The system provides market transparency and is essential to OTC hedging, especially for determining the geographic distribution of price differentials.

5.2 How Interstate Gas Price Data are Collected and Published

As the gas market liberalized in the 1980s, a number of electronic information platforms, trade publications and exchanges began collecting and publishing price information. The primary electronic platform sources are Reuters, Bloomberg, and Dow Jones; the three main trade publications are *Gas Daily, Inside FERC Gas Market Report*, and *Natural Gas Intelligence*, and the primary exchanges are the Intercontinental Exchange (ICE) and the New York Mercantile Exchange (NYMEX). Enron-on-line (EOL) was also a major source of price information until its demise in 2002.

Initially, price data were collected by a relatively simple telephone survey of traders and others active in the market. As familiarity with the procedure grew, many sales contracts were indexed to published prices. Following the California energy crisis, however, it was discovered that a large number of companies had reported false data in order to benefit their indexed sales or purchases. On that discovery, the methods by which natural gas prices are collected and published underwent substantial review at FERC and by an industry Committee of Chief Risk Officers. The consequence was a far more rigorous arrangement. Risk managers, rather than traders, now report prices. The submissions are subject to audit and it can be a criminal offence to knowingly report false prices.

Reporting companies normally submit spreadsheets to the trade press for purchases and sales for each trading day at a variety of market centers and hubs. The data are tabulated by the publisher. A price index, which is usually a volume weighted average, is then calculated. Along with the index, a price range – high and low – is usually published. Most publishers screen the data for outliers and omit them from the index calculation and the published range. This price collection system covers almost all natural gas in interstate commerce.

It is significant that the industry and the trade press acknowledge a range of prices. Frequently the difference between the high and low price at a particular time and location is not great, but during periods of rapid market change the range can become quite wide. Given the way the physical natural gas market works and the way that prices are reported, the industry understands that with variability, the "highest" market price during a trading period will often be significantly higher than the average.

There are three main categories of natural gas price information: daily; month-ahead or "bid week" prices; and forward price "strips." (Weekly prices are also published, but they are used less frequently.) Daily prices are set for deliveries the following day or over the weekend and holidays. Bid week prices are prices determined for deliveries over the whole of the prompt month and are designed to mesh with futures prices. The NYMEX Henry Hub natural gas contract for delivery in the prompt month expires three business days before the end of the month, and this sets the time scale for bid week prices. Forward prices or price strips for various market centers are usually provided by banks and financial brokers. They are often stated as a differential from futures prices for forthcoming months as determined on NYMEX.

5.3 Why There is a Range of Market Prices in the Barnett Field

Economists have a short-hand expression that describes the results of a perfectly competitive market – the law of one price, or LOP. In the abstract, the LOP makes sense: Arbitrage will quickly eliminate any price difference. Most markets, however, are not perfectly competitive, as depicted in the ideal model upon which the LOP is based. Imperfections arise due to imperfect information, buyer or seller market power, unexpected shocks to the infrastrure, or a host of other issues.

5.3.1 Imperfect Information

Just about everyone has experienced the frustration of seeking the best price in a market. The search may involve websurfing, reading newspaper ads, traveling to stores, conducting telephone surveys, etc. Information is rarely perfect or costless and this is the most common reason why most markets exhibit a range of prices. Gas trading in the physical market is no different. Bilateral deals are usually negotiated over the telephone between traders that know each other. Traders often survey their contacts in advance of a deal in order to assess the market. They also consult the trade press, electronic exchanges, and other sources of public information. Imperfect information results in a range of field prices. Some sellers make good deals and some don't.

5.3.2 Market Power

What economists refer to as "market power" is another reason why the LOP does not always hold. Large producers can frequently segment a market and charge different prices to different customers. This was a major issue in the Alaska Royalty Case. In the 1980s Alaska North Slope (ANS) oil could not be exported, and the surge in ANS production created a West Coast oil surplus. At times, the surplus was nearly one million barrels per day. The only outlet for the surplus was the U.S. Gulf Coast, but it cost around $5 per barrel to move the oil there as compared to refining it in California. In a perfectly competitive market, West Coast oil prices, and the netback to Alaska, would have been driven down until producers were indifferent between selling locally and shipping to the Gulf Coast. However, only three companies controlled ANS production, with BP accounting for half. BP, by itself, could determine the level of the West Coast oil price discount by deciding how much to ship east.

In a similar vein, airlines try to segment ticket sales in order to charge more for business passengers; private colleges and universities discount tuition fees to students whose families are less able to pay; hospitals charge different fees to private patients and insurance companies, etc. Sometimes these price differences reflect different costs, but they may also reflect differences in buyers' willingness to pay, which is referred to as "price discrimination" and is a hallmark of market power.

5.3.3 Market Disruption and Change

A host of superlative adjectives have been used to describe the shale gas revolution. The resource base and the technology to extract it have fundamentally changed the U.S. gas supply picture. Less attention has been paid to the significant impact shale gas development has had on pipeline infrastructure and pricing in various market centers. Five years ago the industry expected much of future U.S. gas supply would depend on LNG imports. Gas could be expected to flow from various ports of entry along the coasts and inland to major market centers. Shale gas changes the prognosis; instead of a gas flow from outside in, the flow will be from the inside out. This is because the most active gas shale deposits are along the Appalachian Mountain Range, the Rocky Mountains and Northern Texas. The shift in gas flows also means that key pricing points – market centers and hubs – are changing. Traditional ideas about price differences between market centers, called "basis", will continue to change.

Shale gas development followed, indeed may have been caused by, the market disruptions from 2005 thought 2008. The rapid rise in natural gas prices following hurricanes Katrina and Rita preceded a similar rise in oil prices and then a collapse of both markets in the winter of 2008-9. Price volatility reflects market uncertainty, and one consequence is a much wider range of observed prices. Technically, traders increase the "bid-ask" spread. With a much wider expanse of bidding, the consequence is a much wider array of high and low prices.

6. Chesapeake's Gas Marketing

6.1 Chesapeake – Dreyfus Sale Contract and Confirms

Chesapeake chose to use a single sales outlet for DFW production; all the volume is sold to Louis Dreyfus for resale. That is somewhat unexpected in that Chesapeake also has its own marketing arm, CEMI. Chesapeake could have chosen to market through CEMI, which would have given it many opportunities to get higher prices. The arrangement also limits DFW's knowledge about marketing details. Chesapeake provided no information on its sales other than the arrangement with Dreyfus, acting as the exclusive marketer.

Chesapeake and Dreyfus use a master standardized contract with daily and monthly confirms that specify price and volume. As explained, this two-pronged approach is commonly used by producers to market gas. Toward the end of each month, Chesapeake and Dreyfus appear to negotiate month-ahead deliveries for the bulk of production. Typically, month-long deliveries are negotiated in the week prior to the month of delivery with separate price and volumes struck over several days of negotiation. Surplus production, over and above volumes set in the month-ahead, is then priced on a daily basis. Overall, month-ahead volumes are about three-quarters of the total, but exact percentages vary with output and season.

Prices in the confirmation documents appear to be negotiated rather than indexed to prices in the trade press. There is one exception. According to the confirms, some monthly sales between November 2008 and March 2009 were indexed to *Inside FERC Gas Market Report* (IFGMR). The price was set at \$0.23 per MMBtu below the published price for the East Texas Houston Ship Channel, with delivery at Carthage Hub (CHK 14168-69). The prices quoted in the confirms, however, were about \$0.50 per MMBtu below this formula, and the difference was not explained. Elsewhere, in all the confirms, there is a reference to indexing at the "Gas Daily Midpoint," but there were no specifics with regard to the pricing point or related details that would allow the price data to be checked. This reference does not appear to have been a basis for pricing.

7. Alternative Gas Marketing Strategies

7.1 The "Net Back" Theory of Pricing

"Net back" calculations are sometimes used to estimate what wellhead prices ought to be. The idea is straightforward. Given the price of gas or oil delivered to its market, wellhead prices can be calculated by subtracting the transportation cost back to the origin. This theory is applicable in limited circumstances. For example, Alaska's ANS can only be marketed through the Trans Alaska Pipeline System (TAPS). Transport rates are set by FERC. So, the producers pay royalties based on the delivered price of ANS, netted back to the North Slope.

Most energy pricing, particularly pricing for pipeline natural gas, is not as simple as the Alaska example. This is because gas pipelines may transport gas from many producing regions and deliver it to markets all along the system. Moreover, there are many competing pipelines; delivery routes overlap in highly complex ways. A good example is the Northwest Pipeline, which connects gas producers in Western Canada and the U.S. Rocky Mountains with consumers throughout the Pacific Northwest. Gas enters the pipeline from both ends and the "null" point shifts back and forth depending on which markets are drawing the most gas. Not far from the null point the Williams Northwest pipeline interconnects with the other region's major trunk line, Gas Transmission Northwest. Not surprisingly, gas-fired power generation is located near the intersection.

Natural gas price differentials, basis, vary in unpredictable ways. Basis does not depend on regulated transmission rates. Instead, it varies depending on marketing costs, which parts of the pipeline system are full and which parts have spare capacity, and a host of factors that may never be known.

As complicated as the Pacific Northwest system is, it is simple compared to the Gulf Coast and Mid-Continent systems, where pipelines are interlaced between multiple producing regions and multiple markets. The natural gas pipeline system in Texas alone is far more complex than either the Alaska or Pacific Northwest example. This is particularly evident because the Barnett Field underlies a major metropolitan area. There are many buyers and many sellers in the Dallas-Fort Worth Metroplex and this produces a complex pattern of pricing.

7.2 The Role of Marketers

Some gas producers, including Chesapeake, have their own marketing arm. Other producers rely on marketers as intermediaries. As noted, the reason why gas marketing can be complex (and costly) is the need to balance variability in production and consumption. Field production is generally predictable; gas consumption far less so. This is because gas demand is driven mainly by weather. A hot spell produces a surge in power demand, which provokes increased gas-fired generation, particularly during peak hours. Likewise, a winter cold spell drives up gas demand for space heating. Gas marketing requires that production and consumption be balanced. Part of the balancing can be achieved by diversity – aggregating many producers and consumers over a wide geographic area. (Sometimes marketers are called "gas aggregators".) Aggregation tends to balance individual swings in production and consumption, but is insufficient to cover all demand variability. There is usually the need for storage, which can be costly.

The DFW-Chesapeake lease does not allow Chesapeake to deduct marketing expenses when calculating the royalty obligation. This reduces the incentive for Chesapeake to market gas on its own. Instead, they retained Dreyfus to market all the DFW production.

Chesapeake made gas prices paid by Dreyfus available, but prices Dreyfus received when marketing the gas are unknown. In contrast, other producers marketed the gas directly; obtaining higher prices than the ones Chesapeake was paid. This is a partial explanation as to why some Barnett gas prices were significantly higher.

7.3 The Local Market for Gas

Table 7.1
Estimated Market for Natural Gas in the Dallas Fort Worth Metroplex

Sector	Base	Low	High
Residential	57,698	57,698	80,746
Commerical	70,002	50,021	70,002
Industrial	477,852	343,623	477,852
Power	132,987	89,767	163,199
Total	738,539	541,109	791,799
Share of State	0.24	0.17	0.25
Barnett 2008	1,563,000	1,563,000	1,563,000
Draw on the Barnett Gas Field	**47.3%**	**34.6%**	**50.7%**

In 2009, the Dallas-Fort Worth Metroplex (suburban and urban population centers in and around the Dallas and Forth Worth areas) held approximately 6.5 million people, 31% of the population of Texas. There is a substantial local market, and, until 2006 when Barnett gas began to ramp up, the Dallas Fort Worth Metroplex had to import natural gas from other parts of Texas. Within the Metroplex, residential users buy natural gas mainly for heating and cooking. The primary distribution company is Atmos, for homes and apartments delivered; there is a variety of commercial and industrial users. Electric generators serving the Metroplex also purchase natural gas.

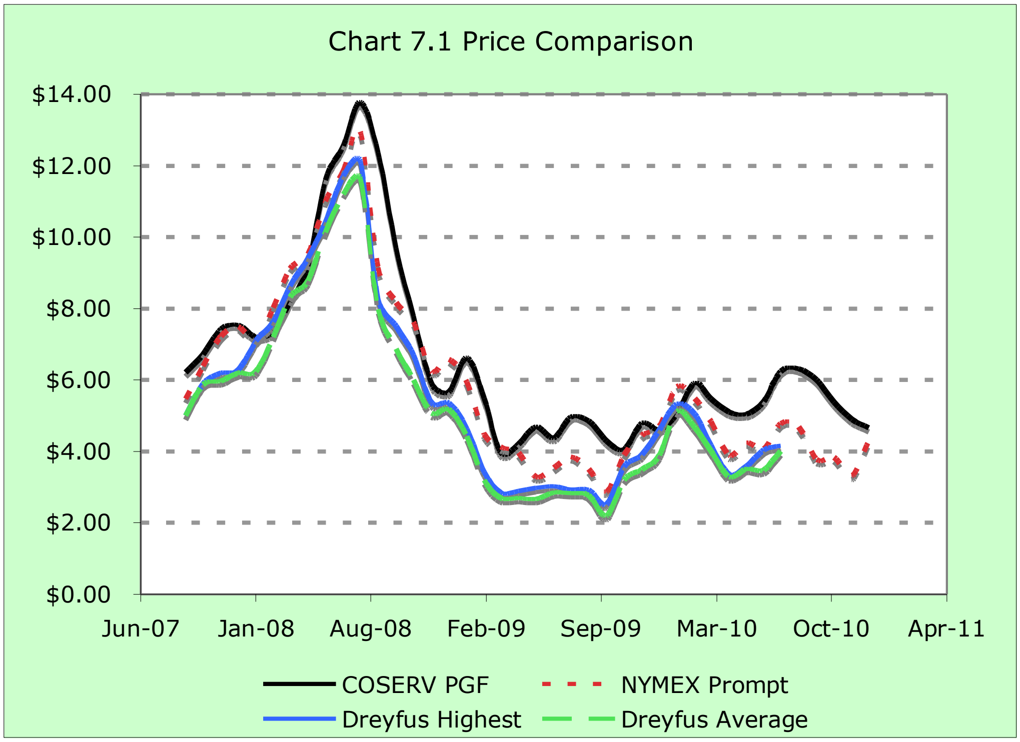
Texas has a deregulated retail market, so a variety of companies sell gas. The market is not, however, transparent. In recent months (2011) Natural Gas Intelligence began reporting prices in the Barnett and other shale gas fields. Before, then, however, gas price reporting was limited to a number of market centers some distance from the Dallas-Fort Worth Metroplex. These indexes failed to capture the diversity in the local market.

7.4 CoServ Example

CoServ is a public utility that markets electricity and gas in the Dallas-Fort Worth area. Their gas marketing approach is to charge a fixed fee for use of their distribution system and per-unit charge for the natural gas. The per-unit charge for natural gas is referred to as the "Purchased Gas Factor" or "PGF." The PGF varies from month-to-month reflecting market changes. CoServ describes its wholesale gas costs on its website:

> PGF is short for "Purchased Gas Factor." By multiplying this factor by your gas usage, you'll arrive at the dollar figure in the PGF line item of your monthly statement. That amount represents our wholesale costs for the gas you used during the billing cycle. Most businesses charge a set price for a particular product or service, and you'll probably never know the real wholesale value. But, at CoServ Gas, we clearly disclose our wholesale cost of energy on your bill. Whenever the PGF fluctuates, it means our wholesale cost of gas went up or down... CoServ Gas is a local distribution company, which means we deliver natural gas to your home or business through our pipelines. However, we don't actually drill for gas. Instead, we purchase it from several wholesale suppliers, and we continually strive to secure the most competitive rates. You benefit from our extra effort since we don't mark up those costs… The PGF is an estimate, because complete information regarding our gas costs isn't available at the time we send your bill. However, we adjust any over-charges or under-charges each month… Most of our business costs stay fairly steady. But, due to the volatility of natural gas prices, what we pay for gas can change significantly within just a few days. Therefore, it makes more sense to separate the PGF as its own line item. This way, we can easily adjust it to reflect changes in our wholesale gas costs. How do you calculate the PGF? It includes two components:
>
> - the estimated cost of the gas itself
> - the cost for transporting the gas from our supplier to CoServ

I requested historic PGF data from CoServ, and, since they are public data, CoServ was willing to provide them. Chart 7.1 compares CoServ's wholesale prices, the NYMEX prompt month price, the average price paid by Dreyfus to Chesapeake, and the daily "highest" paid by Dreyfus during the relevant period. (The methodology for calculating the highest Dreyfus price is explained more completely in Section 9.)



Since the Barnett field produces more gas than is consumed locally, it has been argued that the netback theory implies that gas prices at the DFW lease ought not to be higher than the price at a market center, such as Carthage, Louisana, or Waha in West Texas, less the cost to move the gas to that center. The same logic would also hold for CoServ's purchases; the utility should have been able to buy gas discounted from market center prices. Instead, one of CoServ's executives explained that the company typically paid a market center price, plus the cost of transporting gas from there to its distribution system. As discussed earlier, these higher prices may be explained by marketing costs and poor price information about the Texas intra-state gas market.

Table 7.2 Price Comparison

Date	COSERV PGF	NYMEX Prompt	Houston Ship Channel IFGMR	Dreyfus Highest	Dreyfus Average
Sep-07	6.22	5.47	5.23	5.00	5.00
Oct-07	6.71	6.38	6.13	5.88	5.87
Nov-07	7.42	7.23	6.92	6.20	5.97
Dec-07	7.54	7.49	6.87	6.28	6.19
Jan-08	7.19	7.08	6.73	7.10	6.24
Feb-08	7.36	8.03	7.74	7.62	7.20
Mar-08	8.19	9.11	8.73	8.63	8.33
Apr-08	9.20	9.52	9.25	9.41	8.77
May-08	11.60	11.01	10.83	10.41	10.13
Jun-08	12.55	11.86	11.66	11.71	11.20
Jul-08	13.78	12.96	12.84	12.13	11.64
Aug-08	12.36	9.15	9.04	8.27	7.98
Sep-08	9.70	8.17	8.06	7.51	6.88
Oct-08	7.79	7.62	7.27	6.70	6.00
Nov-08	5.91	6.26	5.72	5.37	5.07
Dec-08	5.66	6.59	6.11	5.35	5.18
Jan-09	6.62	5.94	5.26	4.64	4.42
Feb-09	5.49	4.49	3.86	3.42	3.20
Mar-09	3.99	4.13	3.51	2.84	2.70
Apr-09	4.20	3.97	3.65	2.90	2.71
May-09	4.70	3.29	3.19	2.97	2.66
Jun-09	4.38	3.53	3.48	3.03	2.84
Jul-09	4.96	3.85	3.85	2.94	2.83
Aug-09	4.86	3.51	3.41	2.93	2.77
Sep-09	4.29	2.88	2.69	2.52	2.20
Oct-09	4.05	3.89	3.68	3.57	3.20
Nov-09	4.80	4.45	4.23	3.91	3.50
Dec-09	4.60	4.71	4.57	4.60	3.90
Jan-10	5.07	5.81	5.83	5.33	5.12
Feb-10	5.91	5.49	5.48	5.05	4.67
Mar-10	5.47	4.83	4.77	4.18	4.01
Apr-10	5.11	3.90	3.92	3.36	3.30
May-10	5.05	4.25	4.15	3.58	3.51
Jun-10	5.39	4.08	4.05	4.04	3.48
Jul-10	6.25	4.78	4.69	4.17	4.02
Aug-10	6.32	4.69	4.59		
Sep-10	6.01	3.78	3.70		
Oct-10	5.39	3.84	3.86		
Nov-10	4.90	3.32	3.25		
Dec-10	4.66	4.31	4.22		
Average	**6.70**	**6.16**	**5.93**	**5.53**	**5.22**

Table 7.2 provides month-by-month detail on the various prices and computes an average for the period. CoServ's average price was $0.54 per MMBtu higher than the NYMEX price, $0.77 per MMBtu higher than the Houston Ship Channel Price index, and $1.48 higher than prices used by Chesapeake as the basis for royalty payments for the period September 2007 through July 2010.

CoServ's purchase costs and shale gas data from NGI demonstrate that there was a robust local market in which gas could have been sold for a premium, if Chesapeake had chosen to market DFW gas directly, rather than through Dreyfus.

8. Royalties Paid for Barnett Natural Gas on Leases Neighboring DFW

8.1 Data Sources

Due to the size and location of the Barnett field, production companies leased mineral rights from a wide variety of public and private land owners. Most public entities in the Dallas Fort Worth Metroplex – for example, cities, counties, school districts, and parks – implemented a transparent leasing process. Moses, Palmer & Howell, L.L.P. made a public information request to public entities and obtained copies of the their leases and royalty payments. The data were compiled by the firm and given to me for analysis. The data requested included lease, county, operator, and monthly figures on the Btu of the production, mcf volume, and unit price.

There are other sources of price data on Barnett field production. Severance tax data from the Texas Comptroller of Public Accounts are frequently used for price comparisons. Unfortunately, these data do not include Btu information, and prices are reported in mcf. In many cases this makes little or no difference. Given the diversity of the Barnett field, however, mcf pricing can lead to substantial distortions. For example, prices for gas with Btu values of 1,100 per cf would be expected to be 13% higher than most DFW gas. Thus, it would be inappropriate to use Comptroller prices unless adjustments are made for Btu differences. The great advantage of the public entity data collected for this case is the availability of Btu information. This allows an unambiguous calculation of the highest price.

Seventeen cites and counties provided leasing data for the various public lands that they manage. There are 27 different operators (production companies,) ranging from Aruba

Petroleum to XTO. Most of the entities leased to a single operator. Others, like the City of Fort Worth, leased to four different companies. A complete listing of entities providing data, leases, and operators is included in my work papers.

8.2 Steps in Processing the Data

The first step in processing the public entity data was to convert prices from dollars per mcf to dollars per MMBtu. If a Btu value was not available the observation was discarded. Likewise, if the Btu value was higher than 1,100 per cf, the observation was discarded. The three highest prices were selected from the remainder. I reviewed the three highest prices, rather than just the highest, in order to prevent data entry errors or accounting anomalies from being selected as the highest.

As a general rule, the highest of the three prices was similar to or identical to the second and third highest. There were also substantial volumes associated with the three prices per month that were reviewed. Out of the 40 months analyzed I found three "highest" prices that were problematic. In those cases, I selected the second highest, rather than the highest. Where appropriate, I also corrected the primary data.

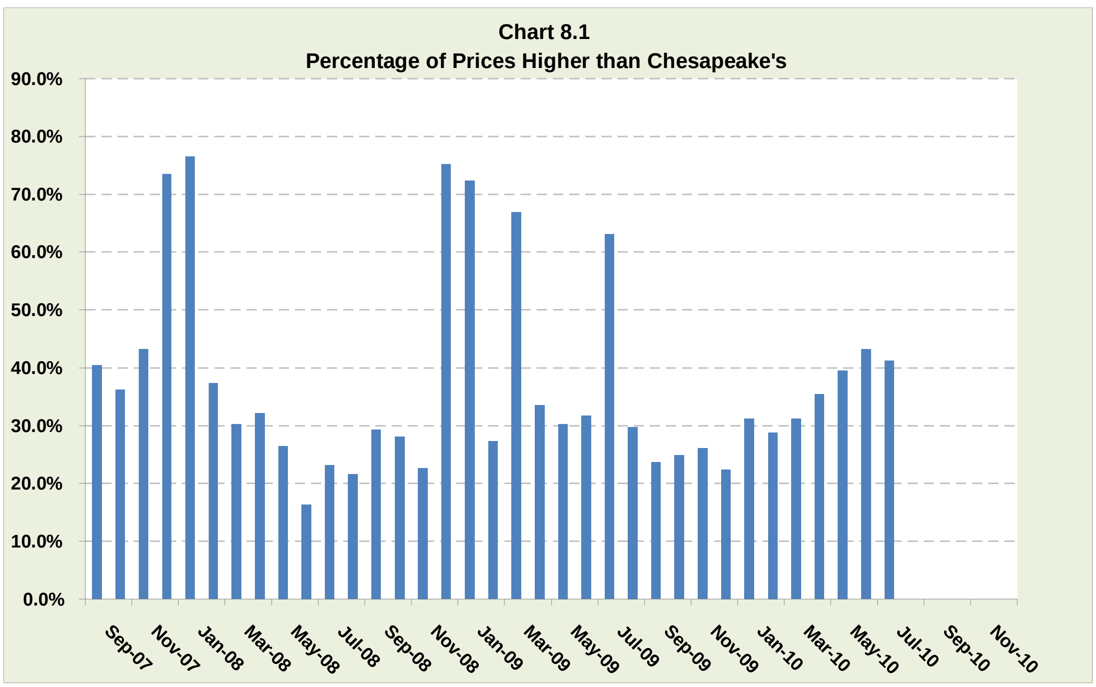
Table 8.1 summarizes the results for September 2007 through December 2010. The first three columns after the date are the three highest prices. The fourth column is an average of those prices and the fifth column is a (non-weighted) average of all prices in the public entity database. The final column is the average price Dreyfus paid Chesapeake based on confirms between the companies.

Table 8.1
Prices in $/MMBTU from Public Entity Data Base

Date	Highest Used in Underpayment Calculation	2nd Highest	3rd Highest	Average of Three Highest	Public Entity Average	Chesapeake Price to DFW
Sep-07	5.68	5.23	5.23	5.38	4.44	5.00
Oct-07	6.03	6.03	6.02	6.03	5.24	5.87
Nov-07	6.83	6.83	6.83	6.83	5.93	5.97
Dec-07	6.85	6.85	6.85	6.85	5.96	6.19
Jan-08	6.85	6.85	6.85	6.85	6.03	6.24
Feb-08	7.74	7.74	7.74	7.74	6.80	7.20
Mar-08	8.66	8.66	8.66	8.66	7.71	8.33
Apr-08	11.02	11.01	9.31	10.45	8.24	8.77
May-08	10.90	10.90	10.90	10.90	9.55	10.13
Jun-08	11.57	11.57	11.57	11.57	10.19	11.20
Jul-08	12.73	12.73	12.73	12.73	11.17	11.64
Aug-08	8.97	8.97	8.97	8.97	7.68	7.98
Sep-08	7.76	7.76	7.76	7.76	6.60	6.88
Oct-08	6.80	6.80	6.80	6.80	5.45	6.00
Nov-08	5.81	5.81	5.80	5.80	4.38	5.07
Dec-08	6.31	6.31	6.24	6.29	5.07	5.18
Jan-09	5.62	5.62	5.60	5.61	4.59	4.42
Feb-09	4.14	4.14	4.12	4.13	3.16	3.20
Mar-09	3.74	3.74	3.70	3.72	2.77	2.70
Apr-09	3.60	3.59	3.59	3.59	2.69	2.71
May-09	3.30	3.24	3.15	3.23	2.49	2.66
Jun-09	3.50	3.41	3.41	3.44	2.68	2.84
Jul-09	3.85	3.62	3.62	3.70	3.00	2.83
Aug-09	3.34	3.34	3.28	3.32	2.69	2.77
Sep-09	2.76	2.76	2.76	2.76	1.99	2.20
Oct-09	3.79	3.79	3.79	3.79	2.87	3.20
Nov-09	4.22	4.22	4.22	4.22	3.38	3.50
Dec-09	4.83	4.83	4.83	4.83	3.64	3.90
Jan-10	5.79	5.79	5.79	5.79	4.79	5.12
Feb-10	5.35	5.35	5.35	5.35	4.34	4.67
Mar-10	4.70	4.70	4.70	4.70	3.85	4.01
Apr-10	3.82	3.82	3.82	3.82	3.08	3.30
May-10	4.18	4.17	4.17	4.17	3.44	3.51
Jun-10	4.53	4.53	4.53	4.53	3.42	3.48
Jul-10	4.69	4.66	4.65	4.67	3.89	4.02
Aug-10	4.69	4.69	4.69	4.69	3.87	
Sep-10	3.81	3.80	3.80	3.80	2.96	
Oct-10	3.83	3.82	3.82	3.82	3.16	
Nov-10	3.37	3.37	3.37	3.37	2.88	
Dec-10	4.23	4.23	4.23	4.23	3.73	
Average to Jul-10	**6.01**	**5.98**	**5.92**	**5.97**	**4.95**	**5.22**

8.3 Description of the Price Distribution

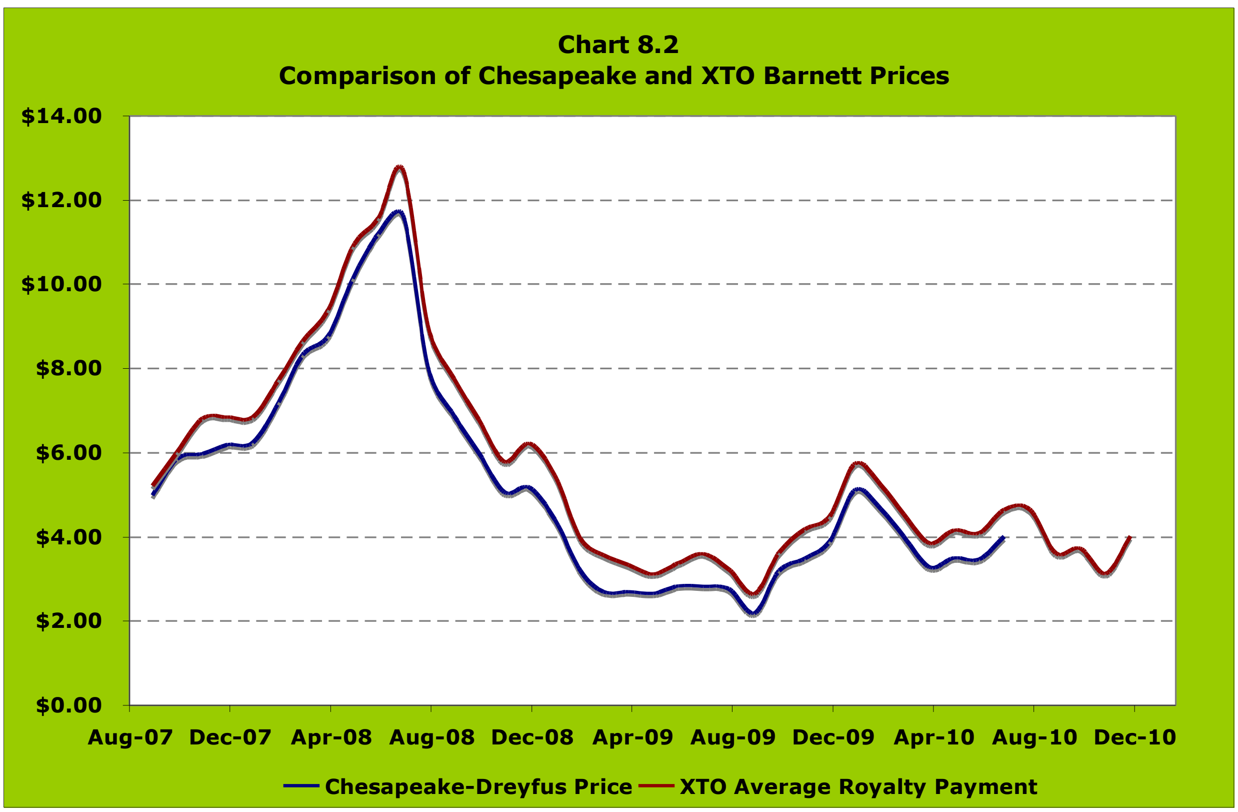
As explained earlier it is not uncommon for there to be a wide distribution in natural gas prices, even after adjustments are made for quality and location. This phenomenon is easily observed in the public entity data. For example, in October 2008 prices ranged from $3.57 to $6.80 per MMBtu. This wide range is explained in part by the dislocations associated with the financial crisis. Normally the range is smaller, but there is always some difference between the highest and the lowest.



A confirming element of analysis leading to an estimate of the highest price in the field concerns the general price distribution, not just the width between high and low. Are the high prices observed anomalies, or are they part of a diverse group of market prices? This issues can be analyzed by calculating the volume of royalty payments in the public entity data base that are higher than the Chesapeake-Dreyfus average monthly price. Through the period the percentage of volume with prices higher than Chesapeake varied from 16.4% to 76.5%, averaging 37.6%. Chart 8.1 illustrates the distribution.

8.4 Comparison of Operator Prices

A question naturally arises as to which companies are marketing their gas for the highest prices. XTO typically pays the highest royalty value. This is not surprising because XTO also has a large marketing organization in the Dallas-Fort Worth Metroplex. Chart 8.2 illustrates the differences between the Chesapeake-Dreyfus price and average per-Btu royalty payments made by XTO on the leases where it is the operator. On average, XTO's royalty payments were $0.64 per MMBT higher than Chesapeake's prices.



9. Calculation of Chesapeake's Underpayment to DFW

9.1 Higher Prices Paid by Dreyfus

It is my understanding that Chesapeake pays DFW royalties based on average proceeds from Dreyfus. On its face, this is inconsistent with lease terms, because there is variation in the monthly and daily prices negotiated between the two companies. In other words, Chesapeake made no attempt to value royalties on the basis of higher prices Chesapeake clearly received during the month. Data provided by Chesapeake in its confirms allowed me to make that calculation and estimate the difference in royalty obligation.

The most obvious example of this omission arises from the multiple day negotiation that sets month-long deliveries. For example, for the month of August 2009 Chesapeake and Dreyfus negotiated four separate deals. The first deal (CHK 15026) made on July 27 was for 15,000 MMBtu of deliveries each day during August at $2.90 per MMBtu. The second deal (CHK 15016) was 10,000 MMBtu per day at $2.84, negotiated on July 28. The third deal (CHK 15031) made on July 29, was for 10,000 MMBtu at $2.66. The fourth deal (CHK 15021) was for a total of 10,000 MMBtu at $2.81, negotiated July 30. For these four deliveries over the course of August, Chesapeake received a volume weighted average ("VWA") price of $2.813 instead of the highest price of $2.90. As the month of August wore on, Chesapeake made daily or multi-day trades to balance out production. For example, 14,000 MMBtu were sold for delivery on August 6 for $3.09. At the other end of the scale, daily volumes sold for delivery from August 29 through 31 received only $1.90 per MMBtu.

I developed a methodology to determine the highest Chesapeake-Dreyfus prices for delivery on each day – the highest month-long price or the highest daily price – and calculated the total value. I summed the daily values and divided the result by the total monthly volume. I refer to this calculation as the "Dreyfus Highest." These calculations are contained in my work papers in a spreadsheet entitled "Dreyfus Prices 111108." Between September 2007 and July 2010, the Dreyfus Highest price was $0.32 per MMBtu higher than average price paid by Dreyfus to Chesapeake.

Table 9.1
Calculation of Royalty Underpayment Using Dreyfus Highest Price

Date	Total Sales (MMBTU)	Total Value (MMBTU)	"Highest" Value (MMBTU)	Average Price ($/MMBTU)	"Highest" Price ($/MMBTU)	Underpayment per $/MMBtu	Total Underpayment (25%) $
Sep-07	12,213	$61,004	$61,004	5.00	5.00	-	-
Oct-07	507,841	$2,979,350	$2,988,307	5.87	5.88	0.02	2,239
Nov-07	906,305	$5,414,640	$5,619,657	5.97	6.20	0.23	51,254
Dec-07	1,157,172	$7,164,768	$7,264,720	6.19	6.28	0.09	24,988
Jan-08	1,098,392	$6,853,822	$7,801,222	6.24	7.10	0.86	236,850
Feb-08	2,190,008	$15,776,162	$16,690,476	7.20	7.62	0.42	228,578
Mar-08	1,689,480	$14,065,543	$14,577,510	8.33	8.63	0.30	127,992
Apr-08	1,360,817	$11,938,439	$12,805,239	8.77	9.41	0.64	216,700
May-08	1,687,103	$17,088,568	$17,562,639	10.13	10.41	0.28	118,518
Jun-08	1,622,626	$18,173,664	$18,996,827	11.20	11.71	0.51	205,791
Jul-08	1,564,537	$18,208,471	$18,980,729	11.64	12.13	0.49	193,064
Aug-08	1,563,314	$12,474,579	$12,922,979	7.98	8.27	0.29	112,100
Sep-08	1,519,601	$10,450,322	$11,412,204	6.88	7.51	0.63	240,470
Oct-08	2,114,850	$12,683,664	$14,169,495	6.00	6.70	0.70	371,458
Nov-08	1,991,328	$10,446,973	$11,055,231	5.25	5.55	0.31	152,064
Dec-08	2,057,011	$10,656,338	$11,015,994	5.18	5.36	0.17	89,914
Jan-09	2,562,931	$11,328,207	$11,881,122	4.42	4.64	0.22	138,229
Feb-09	1,836,002	$5,879,056	$6,271,047	3.20	3.42	0.21	97,998
Mar-09	2,220,054	$6,004,216	$6,307,543	2.70	2.84	0.14	75,832
Apr-09	2,044,000	$5,530,713	$5,922,705	2.71	2.90	0.19	97,998
May-09	2,070,000	$5,514,885	$6,153,660	2.66	2.97	0.31	159,694
Jun-09	1,985,000	$5,638,770	$6,016,440	2.84	3.03	0.19	94,418
Jul-09	1,854,000	$5,251,535	$5,454,680	2.83	2.94	0.11	50,786
Aug-09	1,745,500	$4,839,563	$5,110,175	2.77	2.93	0.16	67,653
Sep-09	1,945,000	$4,284,445	$4,904,140	2.20	2.52	0.32	154,924
Oct-09	2,527,000	$8,089,795	$9,033,370	3.20	3.57	0.37	235,894
Nov-09	2,499,000	$8,743,205	$9,771,090	3.50	3.91	0.41	256,971
Dec-09	2,801,000	$10,915,893	$12,879,105	3.90	4.60	0.70	490,803
Jan-10	2,045,000	$10,467,015	$10,897,319	5.12	5.33	0.21	107,576
Feb-10	1,978,000	$9,244,635	$9,988,900	4.67	5.05	0.38	186,066
Mar-10	2,160,000	$8,672,185	$9,018,000	4.01	4.18	0.16	86,454
Apr-10	1,749,000	$5,763,195	$5,885,240	3.30	3.36	0.07	30,511
May-10	1,596,000	$5,597,623	$5,718,543	3.51	3.58	0.08	30,230
Jun-10	1,555,000	$5,409,320	$6,280,970	3.48	4.04	0.56	217,913
Jul-10	1,511,000	$6,067,188	$6,295,190	4.02	4.17	0.15	57,001
Aug-10							
Sep-10							
Oct-10							
Nov-10							
Dec-10							
Total	**61,726,085**					**0.32**	**5,008,931**

Table 9.1 summarizes the finding. Over the 40 month period this methodology results in an underpayment of just over $5 million.

9.2 Estimation of Underpayment Using Public Entity Highest Prices

Table 9.2 calculates estimated underpayment by Chesapeake to DFW based on the highest prices obtained from public entity data compared to volumes and prices contained in trade confirms between Chesapeake and Dreyfus. I was not able to complete the calculation for the months August 2010 through December because relevant documents from Chesapeake have not yet been produced. In this table total sales volume (Column 2) and revenue (Column 3) are expressed in MMBtu and taken from Chesapeake-Dreyfus confirms. The estimated monthly average price (Column 4) is calculated by dividing total revenue by total volume. Royalty volumes (Column 5) are estimated by multiplying 25% times the total volume. Column 6 is the public entity highest royalty value taken from Table 8.1. The difference in prices (Column 7) is the highest public entity price less the Chesapeake-Dreyfus price. Underpayment (Column 8) is the price difference times estimated royalty volumes. On receipt of additional documents from Chesapeake Table 9.2 will be updated.

Total underpayment for the period September 2007 through July 2010 is estimated at $12.3 million, excluding interest. The total underpayment through December 2010 is likely to exceed $14 million, plus interest.

Table 9.2
Calculation of Chesapeake's Underpayment to DFW

Date	Confirms Total Sales (MMBTU)	Confirms Total Value (MMBTU)	Confirms Monthly Average Price $/MMBTU	Estimated Royalty Volumes (25%)	Public Entity Highest Royalty $/MMBTU	Difference Dreyfus Average $/MMBTU	Total Underpayment
Sep-07	12,213	$61,004	$5.00	3,053	$5.68	$0.69	$2,091
Oct-07	507,841	$2,979,350	$5.87	126,960	$6.02	$0.15	$19,463
Nov-07	906,305	$5,414,640	$5.97	226,576	$6.83	$0.86	$193,856
Dec-07	1,157,172	$7,164,768	$6.19	289,293	$6.85	$0.66	$190,465
Jan-08	1,098,392	$6,853,822	$6.24	274,598	$6.85	$0.61	$167,541
Feb-08	2,190,008	$15,776,162	$7.20	547,502	$7.74	$0.54	$293,625
Mar-08	1,689,480	$14,065,543	$8.33	422,370	$8.66	$0.33	$141,338
Apr-08	1,360,817	$11,938,439	$8.77	340,204	$11.02	$2.25	$764,441
May-08	1,687,103	$17,088,568	$10.13	421,776	$10.90	$0.77	$325,214
Jun-08	1,622,626	$18,173,664	$11.20	405,657	$11.57	$0.37	$150,030
Jul-08	1,564,537	$18,208,471	$11.64	391,134	$12.73	$1.09	$427,021
Aug-08	1,563,314	$12,474,579	$7.98	390,829	$8.97	$0.99	$387,087
Sep-08	1,519,601	$10,450,322	$6.88	379,900	$7.76	$0.88	$335,445
Oct-08	2,114,850	$12,683,664	$6.00	528,713	$6.80	$0.80	$424,329
Nov-08	1,991,328	$10,446,973	$5.25	497,832	$5.81	$0.56	$280,661
Dec-08	2,057,011	$10,656,338	$5.18	514,253	$6.31	$1.13	$580,850
Jan-09	2,562,931	$11,328,207	$4.42	640,733	$5.62	$1.20	$768,866
Feb-09	1,836,002	$5,879,056	$3.20	459,001	$4.14	$0.94	$430,498
Mar-09	2,220,054	$6,004,216	$2.70	555,014	$3.74	$1.04	$574,697
Apr-09	2,044,000	$5,530,713	$2.71	511,000	$3.60	$0.89	$456,922
May-09	2,070,000	$5,514,885	$2.66	517,500	$3.30	$0.64	$329,029
Jun-09	1,985,000	$5,638,770	$2.84	496,250	$3.50	$0.66	$327,183
Jul-09	1,854,000	$5,251,535	$2.83	463,500	$3.85	$1.02	$471,591
Aug-09	1,745,500	$4,839,563	$2.77	436,375	$3.34	$0.57	$247,602
Sep-09	1,945,000	$4,284,445	$2.20	486,250	$2.76	$0.56	$270,939
Oct-09	2,527,000	$8,089,795	$3.20	631,750	$3.79	$0.59	$371,884
Nov-09	2,499,000	$8,743,205	$3.50	624,750	$4.18	$0.68	$425,654
Dec-09	2,801,000	$10,915,893	$3.90	700,250	$4.83	$0.93	$653,234
Jan-10	2,045,000	$10,467,015	$5.12	511,250	$5.77	$0.65	$333,159
Feb-10	1,978,000	$9,244,635	$4.67	494,500	$5.35	$0.68	$334,416
Mar-10	2,160,000	$8,672,185	$4.01	540,000	$4.67	$0.66	$353,754
Apr-10	1,749,000	$5,763,195	$3.30	437,250	$3.82	$0.52	$229,496
May-10	1,596,000	$5,597,623	$3.51	399,000	$4.17	$0.66	$264,424
Jun-10	1,555,000	$5,409,320	$3.48	388,750	$4.53	$1.05	$408,708
Jul-10	1,511,000	$6,067,188	$4.02	377,750	$4.69	$0.67	$254,851
Aug-10					$4.69		
Sep-10					$3.81		
Oct-10					$3.82		
Nov-10					$3.37		
Dec-10					$4.23		
Total	**61,726,085**	**$307,677,748**	**$4.98**	**15,431,521**		**$0.80**	**$12,338,399**

Sources: Chesapeak/Dreyfus Confirms
Public Entity Royalty Payments

9.3 Underpayment Using Production and Price Data from J.P. Morgan

Confirms between Chesapeake and Dreyfus are the most reliable record of Chesapeake sales volume and price, but they do not exactly match production from the DFW leases or the portion of production on which the royalty obligation is calculated. Likewise, total sales do not match the exact amount DFW was paid or the average monthly price per mcf or Btu DFW received. For data through 2010, the best record of amounts paid, volumes produced, and Btu content of the natural gas is kept by J.P. Morgan. They also keep a record of the highest price they observed in Newark field for each month and the gas's Btu content. These data are summarized and maintained by DFW.

I analyzed the J.P. Morgan data using the same criteria applied to the public entity database. Production volumes and the average monthly prices are based on data collected by J.P. Morgan. Column 2 of Table 9.3 is the amount of production on DFW leases stated in MMBtu. Column 4 of the table is the average price for the month in MMBtu. Total value in Column 3 is calculated by multiplying price times volume. Column 5 is the highest Newark price collected by J.P. Morgan, as long as there is an associated Btu value and the Btu value is 1,100 per cf or less. If either condition is not met, then a "0" is placed in Column 5 for that month.

Column 6 is the highest public entity price for the month and corresponds to Column 6 of Table 9.2. Column 7 of Table 9.3 is the higher of the public entity high price and the Newark price collected by J.P. Morgan.

Table 9.3 continues the analysis on a second page. Given DFW production volumes specified by J.P. Morgan, royalty volumes are calculated at 25%. Three sets of price differences are calculated: 1) The difference between J.P. Morgan's average price for the DFW lease and the highest price in the Newark field they discovered; 2) the difference between J.P. Morgan's average price for the DFW lease and the highest price in the public entity database for the month; 3) the difference between J.P. Morgan's average price for the DFW lease and the highest price either from J.P. Morgan or public entity royalties. If the price difference is positive it is multiplied by the estimated royalty volume to calculate underpayment for the month.

Table 9.3
Alternative Calculations of Chesapeake's Underpayment to DFW

Date	JP Mogan & Chesapeake Website Production (MMBTU)	Total Value (MMBTU)	JP Morgan Average DFW Price $/MMBTU	Newark JP Morgan Price Btu <1.1 $/MMBTU	Public Entity Highest Royalty $/MMBTU	Highest JP Morgan or Publics' Price $/MMBTU
Sep-07	12,213	$61,065	$5.00		$5.68	$5.68
Oct-07	505,021	$3,380,346	$6.69	$6.70	$6.02	$6.70
Nov-07	903,968	$5,400,702	$5.97	$6.91	$6.83	$6.91
Dec-07	1,234,818	$7,646,611	$6.19	$6.82	$6.85	$6.85
Jan-08	1,218,041	$7,613,992	$6.25	$7.08	$6.85	$7.08
Feb-08	1,486,744	$10,833,496	$7.29	$7.82	$7.74	$7.82
Mar-08	1,650,147	$13,741,939	$8.33	$8.77	$8.66	$8.77
Apr-08	1,400,286	$12,288,647	$8.78	$9.34	$11.02	$11.02
May-08	1,696,852	$17,244,870	$10.16	$0.00	$10.90	$10.90
Jun-08	1,462,359	$16,382,664	$11.20	$11.84	$11.57	$11.84
Jul-08	1,334,420	$15,521,073	$11.63	$12.96	$12.73	$12.96
Aug-08	1,729,222	$13,808,196	$7.99	$9.02	$8.97	$9.02
Sep-08	1,644,661	$11,308,862	$6.88	$7.99	$7.76	$7.99
Oct-08	1,917,428	$11,502,719	$6.00	$7.32	$6.80	$7.32
Nov-08	2,031,186	$10,298,778	$5.07	$0.00	$5.81	$5.81
Dec-08	2,031,704	$10,526,831	$5.18	$6.43	$6.31	$6.43
Jan-09	1,962,898	$8,707,650	$4.44	$0.00	$5.62	$5.62
Feb-09	1,924,112	$6,152,316	$3.20	$4.66	$4.14	$4.66
Mar-09	2,170,836	$5,813,461	$2.68	$0.00	$3.74	$3.74
Apr-09	2,036,197	$5,444,272	$2.67	$4.12	$3.60	$4.12
May-09	1,924,388	$5,180,359	$2.69	$3.84	$3.30	$3.84
Jun-09	1,868,828	$5,240,179	$2.80	$3.51	$3.50	$3.51
Jul-09	1,956,915	$5,653,093	$2.89	$3.84	$3.85	$3.85
Aug-09	1,765,384	$4,795,647	$2.72	$3.65	$3.34	$3.65
Sep-09	1,970,217	$4,538,719	$2.30	$3.28	$2.76	$3.28
Oct-09	2,369,809	$7,050,671	$2.98	$3.63	$3.79	$3.79
Nov-09	2,304,095	$10,442,370	$4.53	$4.49	$4.18	$4.49
Dec-09	2,157,706	$9,030,235	$4.19	$4.74	$4.83	$4.83
Jan-10	2,158,377	$10,889,189	$5.05	$5.76	$5.77	$5.77
Feb-10	1,976,644	$9,141,219	$4.62	$5.27	$5.35	$5.35
Mar-10	2,036,675	$8,194,744	$4.02	$4.53	$4.67	$4.67
Apr-10	1,772,468	$5,676,983	$3.20	$3.92	$3.82	$3.92
May-10	1,868,140	$6,445,370	$3.45	$4.13	$4.17	$4.17
Jun-10	1,669,163	$5,730,219	$3.43	$4.32	$4.53	$4.53
Jul-10	1,629,120	$6,479,571	$3.98	$4.60	$4.69	$4.69
Aug-10	1,439,833	$5,936,887	$4.12	$4.58	$4.69	$4.69
Sep-10	1,317,836	$4,433,343	$3.36	$3.77	$3.81	$3.81
Oct-10	1,432,805	$4,308,775	$3.01	$3.73	$3.82	$3.82
Nov-10	1,400,139	$4,665,723	$3.33	$3.21	$3.37	$3.37
Dec-10	1,314,073	$4,521,884	$3.44	$0.00	$4.23	$4.23
Total	**66,685,728**	**$322,033,671**	**$4.83**			

Sources: J.P. Morgan DFW Royalty Record
Public Entity Royalty Payments

Table 9.3 (Continued)

Alternative Calculations of Chesapeake's Underpayment to DFW

Date	Estimated Royalty Volumes (25%)	Average Price Difference if Newark > DFW $/MMBTU	Total Underpayment JP Morgan Price	Average Price Difference if Publics' > DFW $/MMBTU	Total Underpayment Publics Price	Average Price Difference if Highest > DFW $/MMBTU	Total Underpayment Highest Price
Sep-07	3,053			$0.68	$2,076	$0.68	$2,076
Oct-07	126,255	$0.01	$700	$0.00	$0	$0.01	$700
Nov-07	225,992	$0.94	$212,022	$0.86	$193,350	$0.94	$212,022
Dec-07	308,704	$0.63	$194,540	$0.66	$202,972	$0.66	$202,972
Jan-08	304,510	$0.83	$253,074	$0.60	$182,398	$0.83	$253,074
Feb-08	371,686	$0.53	$198,490	$0.45	$168,475	$0.53	$198,490
Mar-08	412,537	$0.44	$183,052	$0.33	$137,083	$0.44	$183,052
Apr-08	350,072	$0.56	$196,279	$2.24	$785,627	$2.24	$785,627
May-08	424,213	$0.00	$0	$0.74	$312,704	$0.74	$312,704
Jun-08	365,590	$0.64	$234,051	$0.37	$134,209	$0.64	$234,051
Jul-08	333,605	$1.33	$443,429	$1.10	$366,524	$1.33	$443,429
Aug-08	432,306	$1.03	$445,588	$0.98	$425,731	$1.03	$445,588
Sep-08	411,165	$1.11	$457,994	$0.88	$363,426	$1.11	$457,994
Oct-08	479,357	$1.32	$632,825	$0.80	$383,947	$1.32	$632,825
Nov-08	507,796	$0.00	$0	$0.74	$375,603	$0.74	$375,603
Dec-08	507,926	$1.25	$636,383	$1.13	$573,306	$1.25	$636,383
Jan-09	490,725	$0.00	$0	$1.18	$580,959	$1.18	$580,959
Feb-09	481,028	$1.46	$701,272	$0.94	$453,377	$1.46	$701,272
Mar-09	542,709	$0.00	$0	$1.06	$576,366	$1.06	$576,366
Apr-09	509,049	$1.44	$734,120	$0.93	$471,509	$1.44	$734,120
May-09	481,097	$1.15	$550,925	$0.61	$292,530	$1.15	$550,925
Jun-09	467,207	$0.71	$329,965	$0.70	$325,179	$0.71	$329,965
Jul-09	489,229	$0.95	$465,100	$0.96	$470,257	$0.96	$470,257
Aug-09	441,346	$0.93	$412,001	$0.62	$275,184	$0.93	$412,001
Sep-09	492,554	$0.98	$480,898	$0.46	$224,770	$0.98	$480,898
Oct-09	592,452	$0.66	$389,655	$0.81	$482,726	$0.81	$482,726
Nov-09	576,024	$0.00	$0	$0.00	$0	$0.00	$0
Dec-09	539,427	$0.56	$301,803	$0.64	$347,872	$0.64	$347,872
Jan-10	539,594	$0.71	$385,367	$0.72	$391,162	$0.72	$391,162
Feb-10	494,161	$0.65	$320,695	$0.73	$358,457	$0.73	$358,457
Mar-10	509,169	$0.51	$259,827	$0.65	$329,132	$0.65	$329,132
Apr-10	443,117	$0.72	$319,237	$0.62	$273,461	$0.72	$319,237
May-10	467,035	$0.68	$315,743	$0.72	$336,193	$0.72	$336,193
Jun-10	417,291	$0.88	$368,730	$1.10	$457,772	$1.10	$457,772
Jul-10	407,280	$0.62	$252,101	$0.71	$290,251	$0.71	$290,251
Aug-10	359,958	$0.46	$165,296	$0.57	$203,983	$0.57	$203,983
Sep-10	329,459	$0.41	$135,211	$0.45	$146,903	$0.45	$146,903
Oct-10	358,201	$0.73	$260,267	$0.81	$291,135	$0.81	$291,135
Nov-10	350,035	$0.00	$0	$0.04	$13,186	$0.04	$13,186
Dec-10	328,518	$0.00	$0	$0.79	$259,162	$0.79	$259,162
Total	**16,671,432**	**$0.67**	**$11,236,640**	**$0.75**	**$12,458,959**	**$0.87**	**$14,440,524**

Sources: J.P. Morgan DFW Royalty Record
Public Entity Royalty Payments

Monthly estimates for underpayment for each of the three categories are summed to produce estimated total underpayment. Using J.P. Morgan volumes and highest Newark prices results in an underpayment of $11.2 million from September 2007 through December 2010. Public Entity prices result in an underpayment of $12.5 million. Using the highest of these two price alternatives results in an estimated underpayment of $14.4 million, not including any interest due.

10. Additional Study and Investigation

This report is based on work done to date. As additional data or information become available to me from Chesapeake production or from DFW, tables and charts will have to be updated and a supplemental annex submitted.

11. Credentials and Publications

Appendix A includes a statement of my academic and professional achievements. It also includes a list of all publications.

12. Previous testimony

Since 2006, I have been deposed or testified on the following matters:

- Deposition, Southern California Edison Company vs. United States, Case No. 03-2869C, Federal Court, September 28, 2006
- Deposition, Natural Gas Anti-Trust Cases I, II, III, IV and V, Case No. 0544516, State of California, April 25, 2008
- Deposition, E. & J. Gallo Winery vs. Encana Corporation, et. al., Case No. CV F 03-5412 AW1 DLB, State of California, May 29, 2009

- Testimony, on behalf of the Mississippi Public Service Commission Staff, concerning the need for a Coal Gasification Power Generation Plant, Jackson Mississippi, October 5 to 9, 2009
- Testimony, on behalf of the Mississippi Public Service Commission Staff, concerning the retrofitting of Plant Daniel, Jackson Mississippi, January 25, 2011

13. Compensation

I am being paid $300 per hour to conduct research, prepare this report and appear as a witness on behalf of DFW

14. Signature

November 11, 2011

Samuel A. Van Vactor

Date