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1.0 Introduction and Qualifications

My name is Claire P. Gotham. I am President of GSC Energy, Inc. ("GSC"), an energy consulting firm based in Atlanta. GSC specializes in consulting to the energy industry on a variety of topics, from financial risk management to physical asset management. We also provide training to the energy industry, through public and private seminars. I have been in my current position as President since May, 2006. Prior to GSC, I held a position with Deloitte and Touche, in their Energy Practice division. In that role, I often served as a subject matter expert on energy issues. Prior to Deloitte, I was an independent consultant for three years, serving energy clients in the Southern California area. Prior to my time as an independent consultant, I was a physical and financial natural gas trader for three energy trading companies and a large investor-owned utility. I graduated cum laude from Tulane University in 1993.

I am an expert in physical and financial natural gas trading, scheduling, energy planning, risk management, commodity settlement, pricing development from production basins to the end user burner tip and assisting clients with implementing business processes and technology tools designed to achieve higher levels of operational efficiency, internal controls, and data integrity. Both my trading and consulting experience have provided me with significant exposure to the development of accurate pricing methods for sales to end-user customers, as well as the procurement and hedging necessary to support such sales. I have become intimately familiar with the economic and non-economic business considerations influencing the pricing of natural gas to end-users in the U.S.

I also have significant experience in creating risk management programs, including establishing independent risk controls, drafting policies and procedures for market and credit risk, educating senior management with respect to critical aspects of risk management, and implementing processes and quantitative methodologies for gas and power asset optimization. My experience also includes significant work with respect to energy trading and asset management, and assisting clients in reviewing, documenting, and defining business requirements for their natural gas trading programs.

A more complete description of my qualifications and experience is included in **Appendix 1** to this report.

2.0 Assignments and Opinions

I have been asked to serve in an expert witness capacity by counsel for Richard M. Hutson, II, (the "Trustee"), chapter 11 trustee for National Gas Distributors, LLC (the "Debtor"). My assignment in connection to this matter is to perform an independent analysis of the following topics, as well as to assess Smithfield's claims related to these topics:

1. The review and analysis of the Debtor's transactions with its suppliers, transporters, and customers
2. Analysis of factors relevant to the pricing of natural gas to the Debtor's customers and other similarly situated customers
3. Determination of whether the Debtor received reasonably equivalent value in return for the natural gas transferred by the Debtor to the defendants within one year pre-petition
4. Determination of whether the Debtor received reasonably equivalent value in return for incurring obligations to provide natural gas to certain defendants within one year pre-petition.

In performing my study, I have personally interviewed the following individuals:

- Ricky Hering - former CFO at NGD
- Mike Pittman – former gas procurement manager at NGD
- James E. Neal – Lead Accountant, Neal, Bradsher, and Taylor P.A.
- Lani Perdu – Accountant, Neal, Bradsher, and Taylor P.A.
- Rod Soberano - Accountant, Neal, Bradsher, and Taylor P.A.
- Elizabeth Berry – Accountant, Independent

A listing of the documents that were reviewed and/or considered in forming the basis for my opinions is attached to this report as **Appendix 2**.

Based on my study of the documents provided in conjunction with this lawsuit, my energy experience, interviews, and research, a summary of my opinions is set forth below.

1. NGD did not have a sophisticated gas procurement/risk management program, which would have been necessary to supply the defendants at the below-market prices being claimed.
    a. NGD purchased the majority of their monthly gas supplies either in the month just prior to delivery month, or intra-month.
    b. NGD held neither storage assets nor any substantial pipeline assets, through which to hedge their long term price commitments to defendants.
    c. There is no evidence of hedging activity on the part of NGD, either through financial or physical transactions.
2. NGD completely lacked any sufficient control environment.
    a. The overall control environment was completely non-existent, as the owner/founder of the company was able to execute deals, approve pricing, negotiate transport, and secure financing, without any independent verification or oversight.
    b. Due to lack of controls, it was possible for false paperwork to be created and for inappropriate pricing to be suggested to clients.
    c. There is an absence of the necessary paperwork to evidence term supply commitments to the defendants on behalf of NGD.
3. The defendants did not receive pricing that is congruent with the pricing that the rest of NGD's similarly situated clients received for the same time period.
    a. There were three employees functioning as salespeople during the time in questions: Paul Lawing, Rob Shaw and Jason Tripp
    b. Jason and Rob's clients all had very comparable pricing, both from a price average perspective and from a price band perspective.
    c. Paul Lawing's customers received pricing directly from Paul that did not reflect what the other two salespeople were offering to their clients, nor did it reflect the prices at which gas was being procured by NGD. This is true for of all of 2005.

   d. The rest of NGD was unaware of the pricing being given to customers by Paul, as he represented other, much higher prices internally. This is true of the gas procurement functions and accounting function.

4. The defendants did not receive pricing that is congruent with the pricing exhibited by the market for similarly situated end-users for the same time period.
   a. The pricing that the defendants received for gas supplied throughout 2005 was below the market average.
   b. At the end of 2005, natural gas prices rose tremendously, due to an extremely active and destructive hurricane season.
   c. At the end of 2005 (and for any pricing purportedly committed to for 2006) gas was supplied to the defendants at prices that were consistently below both the average market prices for such supply and the entire price range seen in the market.

3.0 Natural Gas Pricing

3.1 General background on Natural Gas Pricing

As with any goods that are bought and sold, the price for natural gas is set through the interaction of the market forces of supply and demand. Natural gas is a commodity, just like wheat, gold or pork bellies. As such, its average price at any given time is set by the buying and selling done by market players.

There are two marketplaces in which natural gas is traded: the physical marketplace and the financial marketplace. In the physical market, all prices represent a value for the actual physical MMBtus of natural gas that will ultimately be delivered from seller to buyer, at a predetermined location, for a set quantity and quality of gas. The term of physical deals may vary from spot, meaning essentially immediately, to future deals involving delivery of physical natural gas at some pre-designated time in the future. Future physical deals can go out as far into the future as any counterparty is willing to commit to with another counterparty.

Financial natural gas deals share many of the same characteristics as the physical deals: they involved the pricing of natural gas, for a specific volume, for a predetermined term. However, financial deals are essentially an exchange of cash flows, not an exchange of cash for a physical commodity. The most well known type of natural gas financial deals is futures contracts. Futures contracts are a type of derivative that trade on a regulated exchange (on the New York Mercantile Exchange, "NYMEX", in the case of natural gas). For details on the NYMEX natural gas futures contracts, see Appendix 3.

Another type of derivative commonly used in the natural gas marketplaces is the swap. Like the futures contract, the swap is essentially an exchange of cash flows with differing characteristics. One cash flow is usually based on a fixed number, while the other cash flow is based upon a floating number. This floating number is usually related to some index that will be published later. Most of the similarity ends there. Futures are regulated and traded on an exchange. Technically, the exchange itself is the counterparty for anyone trading natural gas futures contracts. Swaps are traded in what is referred to as the Over the Counter, or OTC, marketplace. OTC transactions by their very nature are private and the details are only known to the two counterparties. This type of transaction involves some counterparty risk. Futures contracts do not. In summary, swaps and futures are alike because:

- both are risk management tools, often used as place holders for physical deals to be executed later
- both exchange a fixed price for floating one
- no physical delivery takes place (never in swaps, practically never in futures)

However, they differ in that:

- futures are regulated; swaps are unregulated
- futures are standardized; swaps are not standardized
- futures are centralized; swaps are not centralized
- swaps are less liquid
- swaps are not as visible a market
- swaps vary in cost
- swaps come in all sizes
- swaps come in varying maturities
- swaps can manage basis risk
- swaps may have credit risk

3.2 Forward Physical Contracts vs. Swaps

The use of the word forward in the description of a transaction only refers to one thing: the time at which the transaction will occur. It will occur forward in time, in the future. It does not denote whether the transaction is a transaction involving the transfer of physical goods or one that is purely financial in nature.

The transactions described in the Miller Affidavit and herein are forward contracts for the purchase and sale of a physical commodity (sometimes referred to as "physical contracts") and reflect an agreement between two parties for the actual delivery by a seller (the Debtor) to a purchaser (Smithfield Foods) as an end-user of the commodity (natural gas). Such transactions that involve the physical transfer of a commodity are typically documented by use of the NAESB Base Contract, which is the industry-standard contract document for physical contracts prescribed by the North American Energy Standards Board, Inc.

The NAESB Base Contract provides an agreed set of terms and conditions which will apply to subsequent physical contracts for the sale of natural gas as and when the parties may agree to one or more transactions. The NAESB Base Contract was in fact used by the Debtor in its transactions with Smithfield Foods (Smithfield) and the particular transactions involved reflect a series of sales and deliveries of physical goods over the period in question, as set forth in the Miller Affidavit.

Swap agreements are "financial instruments (contracts) that do not represent ownership rights in any asset but, rather, derive their value from the value of some other underlying commodity or other asset,"[1]. The Financial Accounting Standards Board defines a derivative as: "A financial instrument or other contract" with all three of the following characteristics:

a. it has one or more underlyings and one or more notional amounts or payment provisions or both

b. it requires no initial net investment (or practically none)

c. its terms require or permit net settlement [2]

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[1] http://www.eia.doe.govloiaflservicerptlderivative/index.html

[2] FASB Statement no. 133 as amended and interpreted "Accounting for Derivatives and Hedging Activities"

Unlike the transactions involving the physical transfer of a commodity where the NAESB Base Contract was used by Debtor and the other parties, swap participants typically use the 2002 Master Agreement prescribed by the International Swaps and Derivatives Association (ISDA) for their contract documentation[3].

Physical contracts are distinctly different from swap agreements, also known as derivatives, which involve the purchase or sale of financial instruments or derivative instruments and provide for an exchange of cash flows with differing characteristics and an ultimate net "settlement" between the parties. While physical contracts involve the sale and delivery of goods by the seller and the corresponding payment of the purchase price by the purchaser, swap agreements involve the exchange of similar but differing obligations followed by a settlement payment from one party to the other. For example, in a swap transaction one party could "swap" one type of risk such as one dependent on a fixed price for another type of risk such as one dependent on a floating price. That floating price is usually tied to a market-based indicator, such as an index price. The other party takes on the opposite risk. The parties then exchange (swap) a set of payments dependent on the difference between the two cash flows generated by the different risks at specified, agreed upon intervals. No physical commodity is exchanged. By way of contrast, a physical contract is never "settled" to adjust for risk or market fluctuations, and a swap agreement is never settled by the delivery or exchange of goods.

Regardless of whether a physical contract may be labeled as or considered to be a forward contract, the underlying characteristics of the transaction will determine whether the market considers the arrangement to be a swap agreement. A physical contract lacks the essential elements of a swap agreement, in that a physical contract is not a purely financial arrangement between two financial contract parties participating in a financial market. Thus, a forward contract in and of itself is not a swap agreement if the true characteristics of a swap are lacking.

3.3 How Physical Natural Gas Prices Are Built: Transportation and Delivery

All physical natural gas follows the general path coming from the production areas (often referred to as basins) through a series of pipelines, to the burnertip where it will be consumed. In this journey, it will travel along three major types of pipelines: the

[3] See attached copy of an ISDA master agreement

gathering system, the interstate pipeline, and the distribution system. The gathering system moves natural gas from the wellhead to the processing plant. This is done within the production area. The interstate pipeline moves the processed gas from the production area to areas of high gas usage, usually cities or more urban areas. Once the interstate pipeline has moved the gas close to these areas, it is joined by a Local Distribution Company, or LDC. LDCs pick up the gas from the interstate pipeline and move it to all of the individual customers' usage locations. This varies from large factories to an individual home.

I illustrate this path to make the point that each step on the path adds to the cost of the natural gas. There is a cost for the raw gas that comes from the well. There is additional cost to process the gas, move it across interstate pipelines, etc. Where you are buying or selling the gas along this path helps determine its final price. Gas purchased at the burnertip, or final usage site, will be the most expensive, because it includes the most transportation expense.

3.4 Transcontinental Pipeline

The interstate pipeline that is most material to the prices examined here is the Transcontinental Gas Pipeline ("Transco"), which is owned by Williams Company. Transco moves gas from production areas in the Gulf Coast of the United States, along 10,560 miles of pipeline, to market areas in the Southeast, Mid Atlantic and Northeastern States.[4] Transco is divided up into zones: Zones 1-3 represent the supply areas, while Zones 4-6 represent the usage areas.

Because Zone 5 is the closest liquid trading point on the interstate pipeline to NGD's end-use customer base, it was used as a pricing start point. Gas was most often quoted to customers as a Zone 5 delivered price. The "delivered" in this price quote indicates that it was not always easy for suppliers to trade natural gas price solely at Zone 5, so they would build a price, taking the Zone 3 supply price (the closest supply price on Transco that had published index numbers) and add applicable transportation to Zone 5 to achieve a Zone 5 price.[5]

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[4] Information came from Williams.com
http://www.williams.com/productservices/gaspipelines/naturalgas.asp#transco

[5] This is my understanding based on interviews with Mike Pittman and Ricky Hering and from review of documents listed in Appendix 2.

Most often, the customers had distribution rights on one of the LDCs connected to Transco at Zone 5. They would take gas ownership at the citygate at Zone 5 and move it themselves to their end-use sites on the LDC.[6]

4.0 Market Pricing 2005

4.1 Overall Market Prices for 2005

In 2005, natural gas prices across the U.S. had been following a general upward trend, which had been going on for several of the previous years as well. It is my opinion that this was directly related to rising consumption in the U.S., coupled with some decrease in domestic production. To be more specific, here are some factors that can be cited:

- Increased use of gas-fired electric generating power plants[7]
- Strong demand growth nationally [8]
- High oil prices and the linking of oil and natural gas prices[9]
- Decreased production of natural gas[10], due to lower prices in previous years[11]

The U.S. Department of Energy's Energy Information Administration ("EIA") publishes several energy forecasts for the country throughout each year. In August 2005, they had the following to say about natural gas prices for the rest of that year:

"The Henry Hub natural gas spot price_is expected to average $7.63 per thousand cubic feet (mcf) in 2005 and $7.34 per mcf in 2006. In July, the Henry Hub natural gas spot price averaged $7.86 per mcf as hot weather in the East and Southwest increased natural gas-fired electricity generation for cooling demand and crude oil prices increased. The

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[6] This is my understanding based on interviews with Mike Pittman and Ricky Hering and from review of documents listed in Appendix 2.

[7] http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm. U.S. Natural Gas Deliveries to Electric Power Consumers (MMcf)

[8] http://tonto.eia.doe.gov/dnav/ng/hist/n9140us2A.htm. U.S. Natural Gas Total Consumption

[9] http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/reloilgaspri/reloilgaspri.pdf - "The Relationship Between Crude Oil and Natural Gas Prices" by Jose A. Villar, Natural Gas Division, Energy Information Administration and Frederick L. Joutz, Department of Economics, The George Washington University, October 2006

[10] http://tonto.eia.doe.gov/dnav/ng/hist/n9050us2A.htm - Annual History of U.S. Marketed Production (MMcf)

[11] http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm - U.S. Natural Gas Citygate Price, EIA; http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3M.htm - U.S. Natural Gas Wellhead Price, EIA

natural gas market is likely to stay tight over the next couple of months, with prices projected to rise further as the winter heating season increases demand. The Henry Hub spot price is expected to average $8.50 per mcf in the fourth quarter. Although natural gas storage remains above the 5-year average, several factors are expected to continue to support high natural gas prices, including: high world oil prices; continued strength in the economy; the expectation that Pacific Northwest hydroelectric resources will be below normal through the rest of the year; limited prospects for growth in domestic natural gas production; and concerns about the potential effects of hurricanes.

Depending on the region of the country, overall increases for 2005 in natural gas spot prices are expected to range between 18 and 25 percent from the 2004 averages. Citygate prices (prices that natural gas utilities pay at the point where they take delivery) and end-use prices (prices charged by utilities for natural gas delivered to end-use customers, including distribution or other charges not included in the utilities' natural gas costs) are expected to exhibit double-digit percent increases for the second year in a row in most regions. For the upcoming winter, pressure on delivered natural gas prices may be sharpest in regions where heating demands are likely to increase the most, such as in the central portion of the United States."[12]

In fact, gas for physical delivery to Henry Hub, LA averaged $8.635[13] for 2005, while the average financial price, based on the NYMEX natural gas contract last day settlement price, was $8.611/MMBtu.[14] To see this pricing by month, see Appendix 4.

4. 2 Impact of 2005 Hurricane Season on the Natural Gas Market

Hurricanes often have a very bullish effect on the natural gas markets. This is because there is a large amount of natural gas production that is located in the Gulf Coast areas of the United States. As a result, production is often shut-in as a hurricane approaches and is disrupted for a length of time during and after a hurricane. Due to this, even the threat of a hurricane entering the Gulf of Mexico is often enough to send the market upward.

[12] Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 4
[13] Pricing data from Platts' publications "Inside FERC's Gas Market Report" published monthly. See documents list for details.
[14] Pricing data from DTN Prophet X quote system. Also available directly from NYMEX at NYMEX.com.

Prior to the start of the 2005 hurricane season, NOAA (the National Oceanic and Atmospheric Administration, an agency of the Department of Commerce) had already predicted an active storm season[15]. In fact, the season became so active that NOAA issued a revision of its previous outlook on August 2, 2005. At that time, they increased the number of predicted hurricanes for the year from 9 to 11. This number included both Hurricane Dennis and Hurricane Emily, which had already occurred. Of those 11, they expected 5 to 7 of them to be severe. The EIA took this new prediction to be bullish for natural gas prices for the rest of the year, as did the market as a whole. The EIA stated:

"According to NOAA, this may be one of the most active hurricane seasons on record for the Atlantic. With limited spare global crude oil production capacity and U.S. refinery utilization rates in the upper 90-percent range for much of the summer, oil prices are likely to react strongly to any disruption of or damage to petroleum infrastructure. How long prices remain elevated due to a particular storm, however, will ultimately be determined by the severity of damage to petroleum facilities"[16]

Hurricane Katrina landed in the Gulf Coast on August 29, 2005. Its effects were seen in an area totaling 90,000 square miles. "A total of 2.7 million electricity customers lost power. Eleven petroleum refineries were shut down, representing 2.5 million barrels per day – or nearly one-sixth – of U.S. refining capacity. As a result of Hurricane Katrina, more than a quarter of U.S. crude oil production – 1.4 million barrels per day –was shut in. Nearly 9 billion cubic feet per day of natural gas production in the federal Gulf of Mexico was shut in, representing 17 percent of U.S. gas production, with additional production losses occurring in areas under Louisiana's jurisdiction. The Louisiana Offshore Oil Port (LOOP) was shut down, as were a number of major oil and gas pipelines. As a consequence, pipeline deliveries of gasoline, diesel, jet fuel, and propane supplies to the east coast and southeastern states were halted."[17]

As the energy complex in the Gulf Coast was still dealing with the effects of Hurricane Katrina, Hurricane Rita struck on September 24, 2005. That storm did even greater harm statistically to the domestic energy markets than Katrina: 19 refineries were

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[15] Source: www. noaanews.noaa.gov

[16] Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 2

[17] All statistics regarding Hurricane Katrina's effect on energy production and refining come from the DOE, included in statements made to Congress on October 27, 2005 by Energy Secretary Bodman. Testimony transcript available at www.doe.gov

shut down, (this represents almost a third of U.S. refining capacity). All crude production and eighty percent of natural gas production were shut in. In total, 27 natural gas processing facilities were shut in. This represented half of Gulf Coast natural gas processing capability at the time.[18]

4.3 Other Factors that affected pricing in 2005

As mentioned previously, there were other factors that were contributing to higher natural gas prices in 2005. These were overall strong demand in the U.S., higher demand on behalf of electric generators, stronger crude oil prices, and less gas production in comparison to past years.

5.0 NGD Pricing to Smithfield

5.1 Pricing to Smithfield for natural gas supplied in 2005 did not represent reasonable equivalent value in comparison with prevailing market prices.

In 2005, the NGD records show that Smithfield received an average natural gas price of $6.36/MMBtu[19] for supplies delivered to them in Transco Zone 5 at the Piedmont Natural Gas interconnect. My analysis, which involved looking at the historical published prices for the same time period[20] plus all applicable transportation rates and tariffs[21], shows an average market price for Transco Zone 5 of $9.076.[22] This number is the sum of the monthly published index price at Transco Zone 3, as published in Platts' "Inside FERC's Gas Market Report" at the first of each month, plus the applicable transportation cost to move the gas to Transco Zone 5 for the time period.[23] Smithfield received physical gas from NGD each month of 2005 at three locations (Kinston, Tar Heel, and Winston).

To look in even more detail, I also examined the range of prices that were reported by all survey participants that made up each month's average index price. (For a discussion on Platts' methodology for compiling prices, see Platt's "Methodology and Specifications

[18] All statistics regarding Hurricane Rita's effect on energy production and refining come from the DOE, included in statements made to Congress on October 27, 2005 by Energy Secretary Bodman. Testimony transcript available at www.doe.gov
[19] Compiled from prices from worksheet "NGD 2005 Price Discounts Vs. Markets.xls"
[20] See attached prices, published by Platts
[21] See Rates and Tariffs, Transcontinental Pipeline Company, from www.gaspipeline.williams.com
[22] Compiled from information in worksheets "NGD Price History.xls" and "Smithfield Pricing Detail.xls"
[23] See the attached worksheet "NGD Price History.xls" for details.

Guide: North American Gas"[24].) This provided a range, with both a published high and a published low for each month. Using these numbers, the average low market price for 2005 for Transco Zone 5 was $8.829. The average high market price for the same months for Transco Zone 5 was $9.434. Comparing the three numbers (market average, high, & low) to Smithfield's average price for 2005 results in the following:

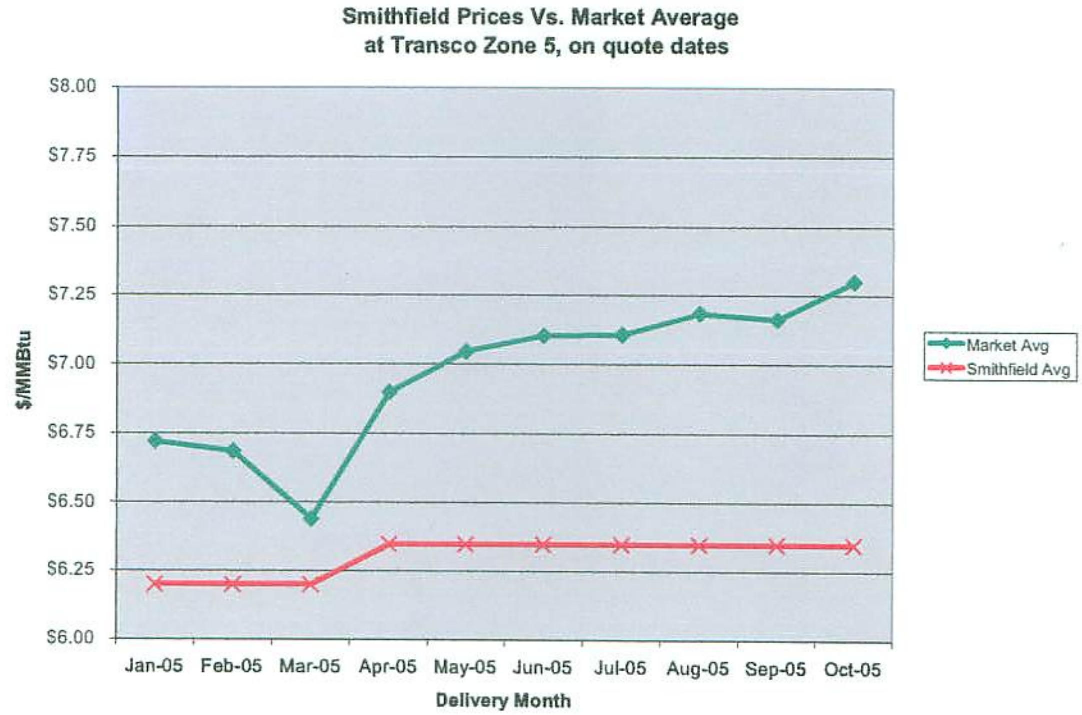
On an annual average basis for 2005, Smithfield's pricing was $2.46/MMBtu below the average low, $2.71/MMBtu below the average market price, and $3.07/MMBtu below the average high for physical gas. This signifies that Smithfield's pricing for 2005 was 28% below the market low price, 30% below the market average, and 33% below the market high.[25]

Please see following charts:

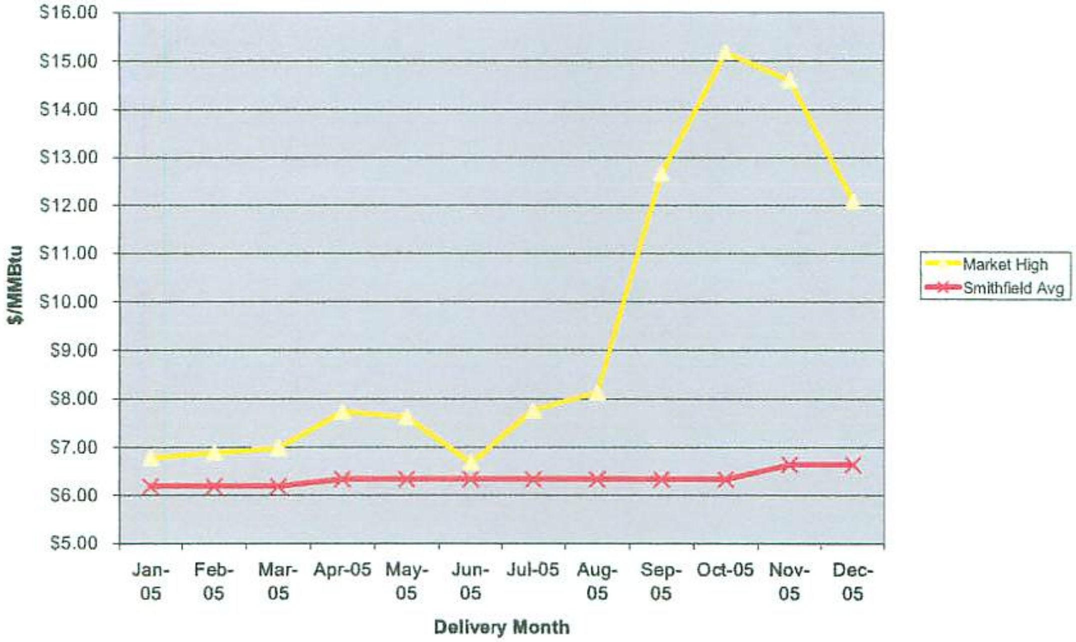
[24] http://www.platts.com/Natural%20Gas/Resources/Methodology%20&%20Specifications/na_gas_methodology.pdf?S=n

[25] See worksheet "NGD Price History.xls" and "Smithfield Pricing Details.xls" for more details.

To view the contrast more clearly, it is possible to isolate each comparison in the charts below.



Smithfield Prices Vs. Market High at Transco Zone 5



5.1.1 Examination of the Timing of Smithfield Pricing

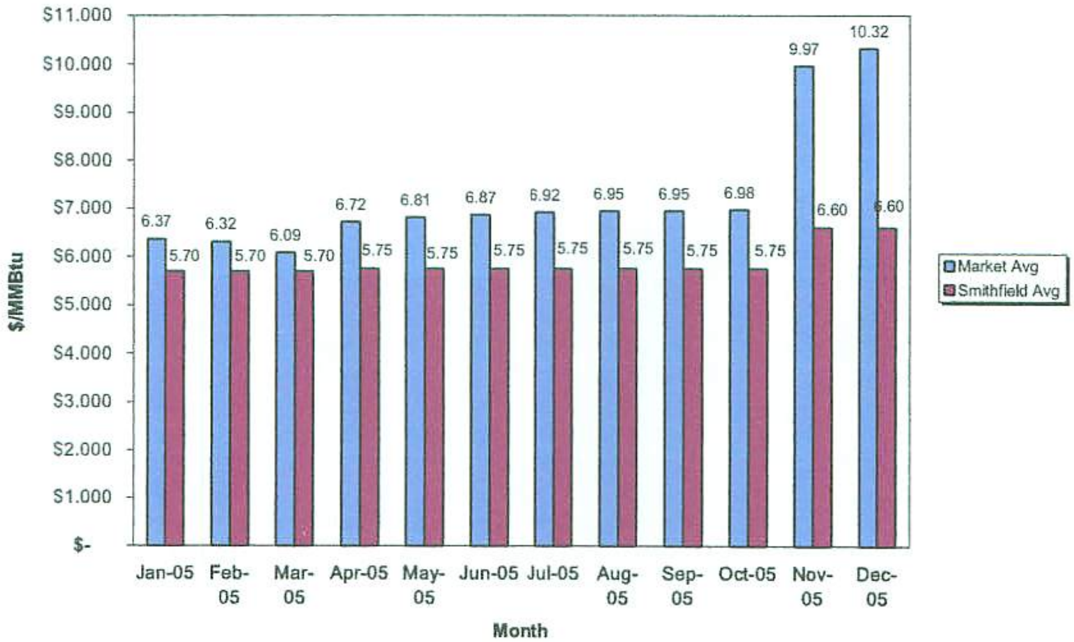
Smithfield received quotes for physical gas delivery over a series of months in the future. According to the Miller Affidavit, Smithfield received the following quotes for natural gas delivery from NGD, on the dates indicated:

1. April 4, 2004 – Offer for full requirements for April 2004 – March 2005 at a capped NYMEX price of $5.70/Dth, plus basis. The final price was $6.20/dth.
2. February 25, 2005 – Offer for full requirements for April 2005 – October 2005 at a capped NYMEX price of $5.75/dth, plus basis. The final price was $6.35
3. August 12, 2005 – Offer for full requirements for November 2005- March 2006 at a capped NYMEX price of $6.60/dth, plus basis. Final price was $6.65.

It is important to look at both the timing of these offers, as well as the elements that make up the final price. While the documentation that supports these offers is not detailed, it can be deduced (based on industry standards, the Debtor's common business practices, and previous history with Smithfield) that the quotes were for the NYMEX portion of the fixed price. The basis portion was left open to be fixed at a later date. It is unclear how or when the basis was later fixed. It is evident, however, that it was eventually fixed, as there is evidence of the final fixed prices of $6.20, $6.35, and $6.65. These final prices indicate a basis of $0.50, $0.60 and $0.05, respectively.

To get an accurate picture of where the natural gas NYMEX contract was trading for the forward months, on the given dates, I examined historical NYMEX quote data. This data is readily available from many published sources. On an annual basis, the NYMEX prices that Smithfield received from NGD were an average of $1.39 lower than that day's settlement price for the contract month in question.[26]

Smithfield NYMEX Prices Vs. NYMEX Settlement Price



It is more difficult to evaluate the basis portion on Smithfield's fixed physical pricing, for two reasons. The first reason is the nature of basis trading. Basis trades are considered OTC trades, or Over-the-Counter. This means that they are private transactions that are not trading on a public exchange (see section 3.1, General Background on Natural Gas Prices, for more information on futures and OTC transactions). Therefore, there is very little data available on what the traded price range is for a given basis product on a given

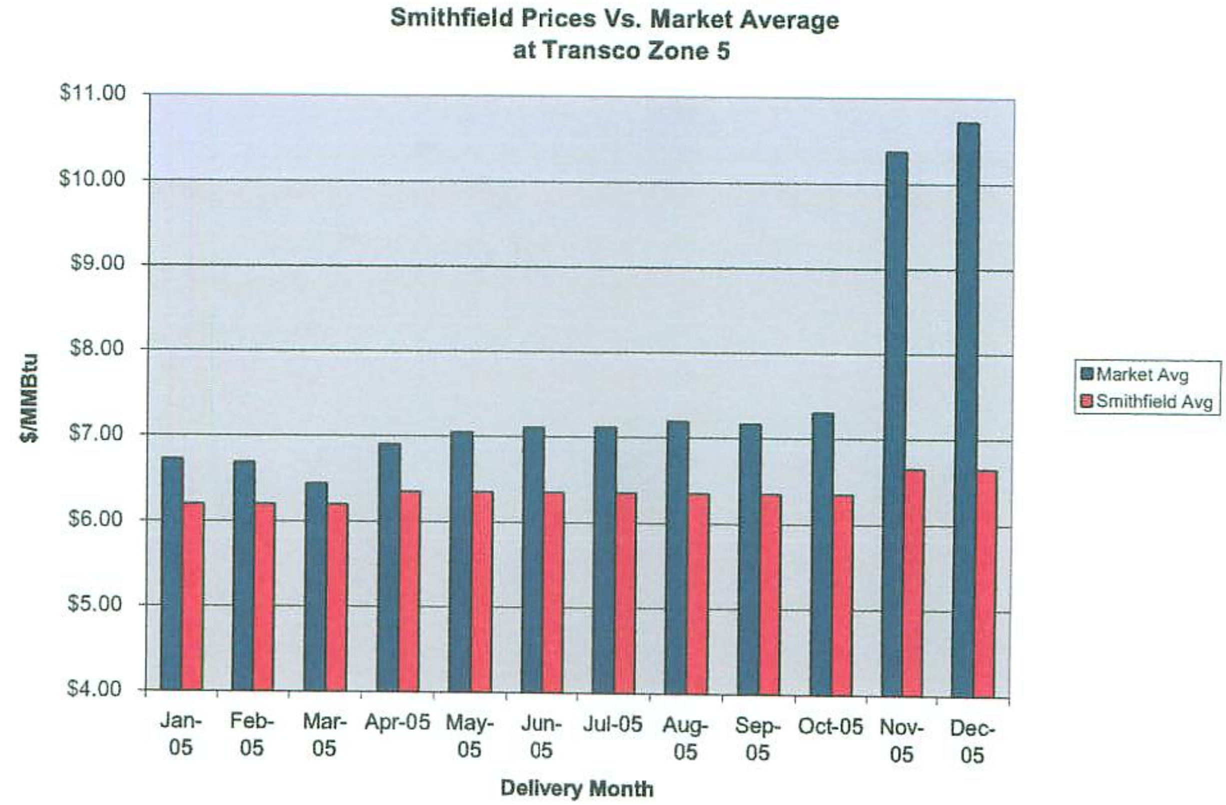
[26] See worksheet "Smithfield Pricing Details.xls", tab "SF NYMEX Date Spec 2005"

day. The second reason is that I have seen no information on when or how the basis portions of these deals were decided. The timing and the benchmarks are unknown.

Because of this uncertainty, it is my professional opinion that that best method for evaluating the validity of the basis portion of each quote is to compare it to historical basis for the location. The formula that I used was this:

NYMEX settlement for the date of the quote[27] + 5-year historical basis average for the month[28], at Transco Zone 3 + applicable transport to move the gas to Transco Zone 5.

Using this formula, the entire fixed price given to Smithfield was \$1.20 lower than the market average for the same delivery months, quoted on the dates listed above. This is 14% lower than the average market price on the same dates.



It is evident that even when examined in the applicable timeframes, the Debtor did not receive fair market value for gas provided to Smithfield for 2005.

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[27] For the date April 2, 2004; the settlement data from April 1, 2004 was used, since the time stamp on the e-mail indicates that this would have been more appropriate.
[28] Historical basis information from BTU Weekly publication.

5.2 Pricing given to Smithfield in relation to any commitment to supply natural gas in 2005 did not represent reasonable equivalent value in comparison with prevailing market prices.

As noted above, the price quotes for natural gas delivery that Smithfield received from NGD for the year 2005 were not in line with prevailing market prices at the same time, nor did they represent reasonable equivalent value for any delivery commitment above and beyond the volumes that were actually delivered. In other words, the price that Smithfield is claiming for December 2005 should not be used in any calculations to value gas that was delivered that month or to value gas that would have been delivered that month under their full requirements deal, but which was interrupted after December 8th.

Smithfield contends that in August 2005, NGD gave them a fixed price for gas to be sold to Smithfield for delivery in the months of November and December 2005. This price was $6.65/MMBtu.[29] NGD did flow gas to Smithfield during November and there was a payment made by Smithfield towards that delivery. NGD also did flow some gas to Smithfield during part of December, prior to interruption due to the circumstances surrounding its bankruptcy. However, even if NGD had been capable of physical flow for all of December and had performed under this pricing arrangement, they would not have been receiving reasonably equivalent value when compared to prevailing market prices for December 2005. As previously discussed, all prices given to Smithfield would have been for physical natural gas delivered to Transco Zone 5. The average market price for this location for December 2005 **on the date of trade execution** was $10.72[30] . The market low and high were $10.52 and $10.92 respectively.[31] When compared to the market average, Smithfield's pricing was $4.07 below that market average price, representing a 37% discount[32]. To get a better view of how Smithfield's pricing for the commitment of gas to be purchased fit into these market prices, see the following chart:

[29] Price information provided by Smithfield.
[30] See spreadsheet "NGDPriceHistory.xls". This was determined taking the NYMEX closing price on the trade date, plus the historical basis at Transco Zone 3 and all applicable transport costs to move it to Zone 5.
[31] See spreadsheet "NGD Price History.xls".
[32] See spreadsheet "Smithfield Pricing Detail.xls"

5.3 NGD Pricing to Other Similarly Situated End-Users was not congruent with prices given to Smithfield for gas supplied.

Another measurement that can be applied to the question of whether NGD received reasonably equivalent value for the gas sold to or committed to Smithfield is the prices given by NGD to other similarly situated customers for the same time period. NGD's internal structure was such that there were three employees functioning as salespeople to end-use clients.[33] To get a clearer picture of how sales were being priced by NGD to current and potential clients, I divided the clients into two groups: those whose accounts were being managed by Paul Lawing ("Paul's Group") and those who were not ("Other Clients"). Those clients who were not being managed by Paul Lawing had either Rob Shaw or Jason Tripp as their salesperson. Breaking it into these two groups, the difference in pricing can be easily seen.

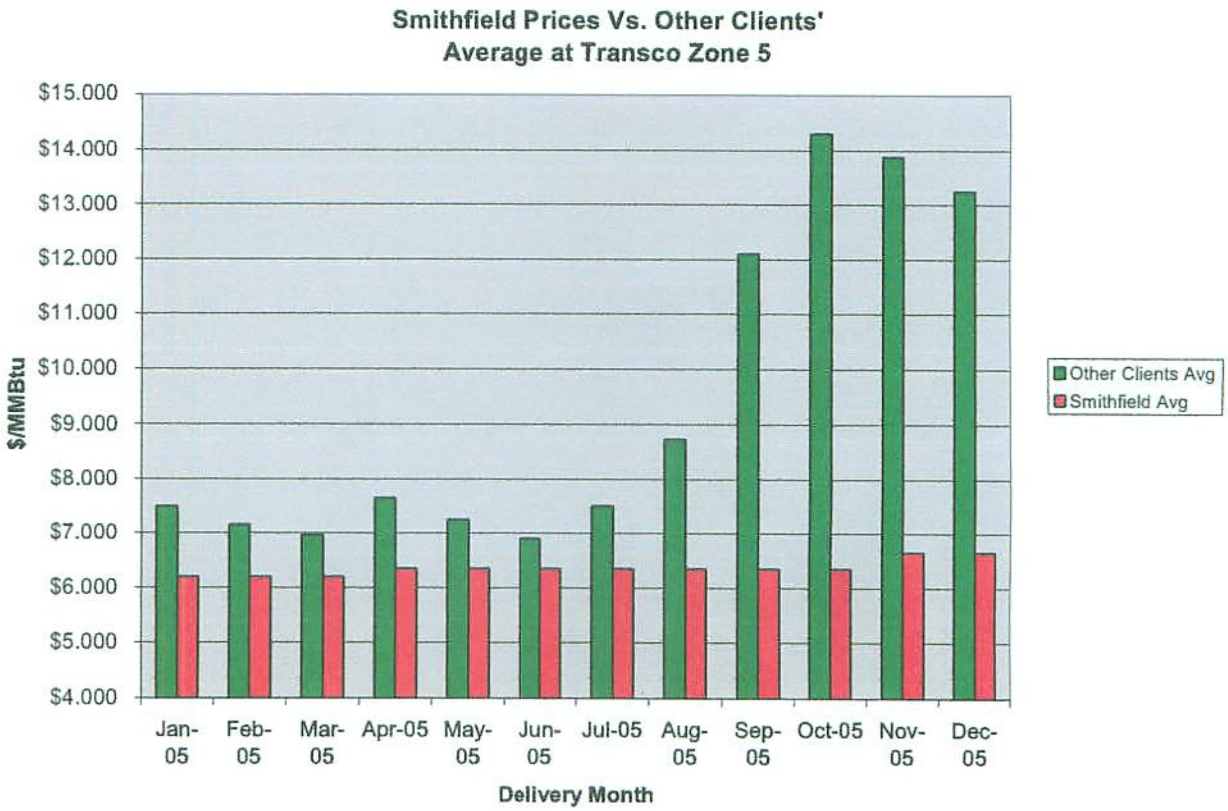
[33] This understanding comes from both my interviews with former NGD employees, as well as review and analysis of documents created by NGD during the time in question.

For the time period of 2005, Paul's Group had an average price of $6.884/MMBtu.[34] In contrast, the average price sold to Other Clients for the same time was $9.434/MMBtu.[35] This represents a difference of $2.55/MMBtu. In other words, Paul's Group was receiving prices that were on average 27% lower than what was being sold to other end-use clients by NGD.

Drilling down even further, we can isolate Smithfield's pricing. For 2005, Smithfield received an average price of $6.36/MMBtu. Again, the average price sold to Other Clients for the same time was $9.43/MMBtu.[36] This represents a difference of $3.07/MMBtu. In other words, Smithfield was receiving prices that were on average 33% lower than what was being sold to other end-use clients by NGD. It is clear from these numbers that the pricing to Smithfield was not congruent with prices to other similarly situated customers for natural gas supplied.

[34] Price data from "NGD Price Discounts vs. Market.xls". Further analysis done by me and can be seen in detail on this sheet.
[35] See worksheet "NGD Price History.xls"
[36] See worksheet "NGD Price History.xls"

For further illustration, please see the following chart:



5.4 NGD pricing to Other Similarly Situated End-Users was not congruent with prices given to Smithfield for commitments to supply natural gas.

As noted above, the price quotes for natural gas delivery that Smithfield received from NGD for the year 2005 were not in line with the prices given to other similarly sit clients at the same time, nor did they represent reasonable equivalent value for any delivery commitment above and beyond the volumes that were actually delivered.

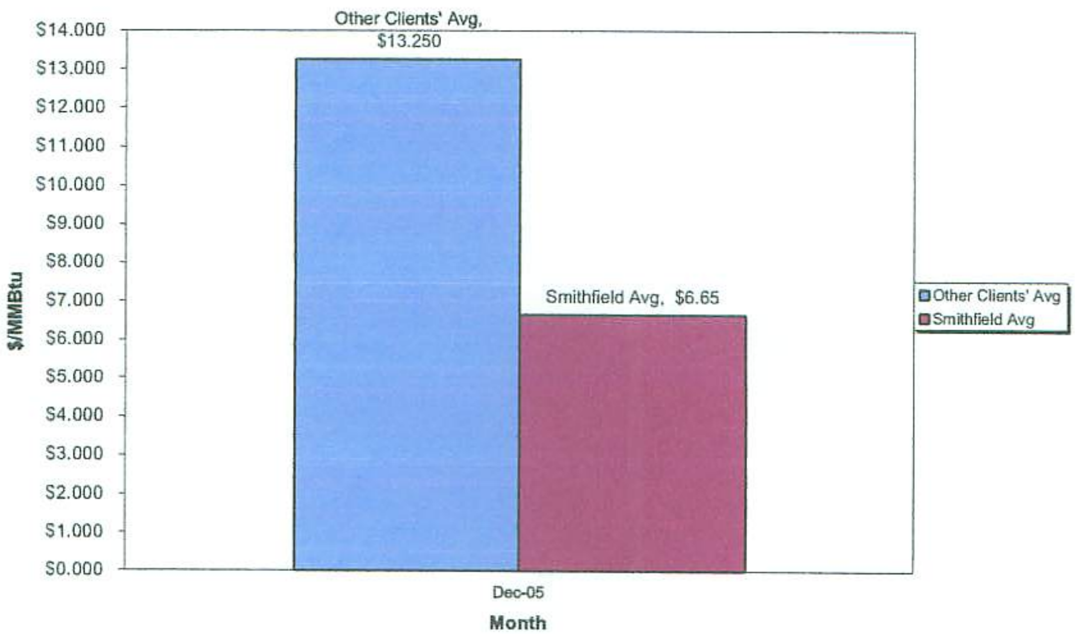
For the time period of December 2005, Paul's Group had an average price of \$9.58/MMBtu.[37] In contrast, the average price sold to Other Clients for the same time was \$13.25/MMBtu.[38] This represents a difference of \$3.67/MMBtu. In other words, Paul's Group was receiving prices that were on average 28% lower that was being sold to other end-use clients by NGD for commitments for gas delivery for December 2005.

[37] Price data from "NGD Price Discounts vs. Market.xls". Further analysis done by me and can be seen in detail on this sheet.

[38] See worksheet "NGD Price History.xls"

Again, it is possible to isolate Smithfield's pricing. For the time period of December 2005, Smithfield received a price of $6.65/MMBtu. Again, the average price sold to Other Clients for the same time was $13.25/MMBtu.[39] This represents a difference of $6.60/MMBtu. In other words, Smithfield was receiving prices that were on average 50% lower that was being sold to other end-use clients by NGD. It is clear from these numbers, that the pricing to Smithfield was not congruent with prices to other similarly situated customers for natural gas commitments for December.

Smithfield Prices Vs. Other Clients' Avg at Transco Zone 5 for December 2005



5.5 Conclusions Regarding Pricing to Smithfield

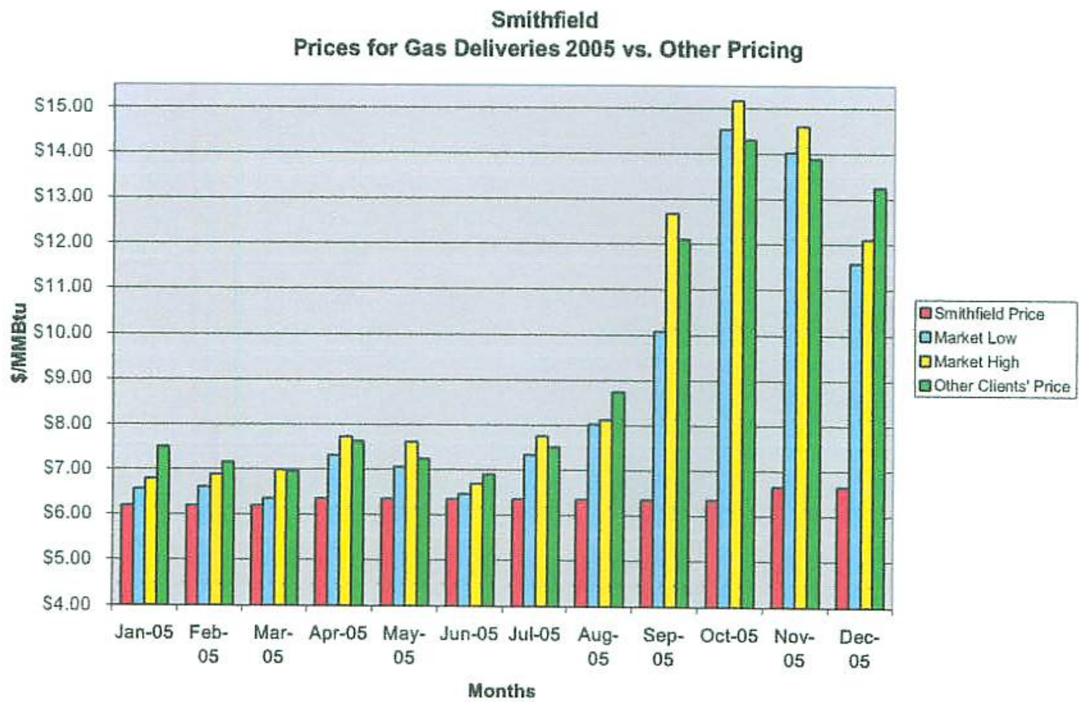
Based on all of the information contained herein I conclude that NGD did not receive reasonably equivalent value for the gas sold or for the obligations incurred. If the Court determines that the gas sold and obligations incurred may be avoided by the Trustee, I understand that the Trustee may recover from the defendant the difference between the

[39] See worksheet "NGD Price History.xls"

fair market value of the gas delivered and the amounts paid by the defendant to or for the benefit of NGD.

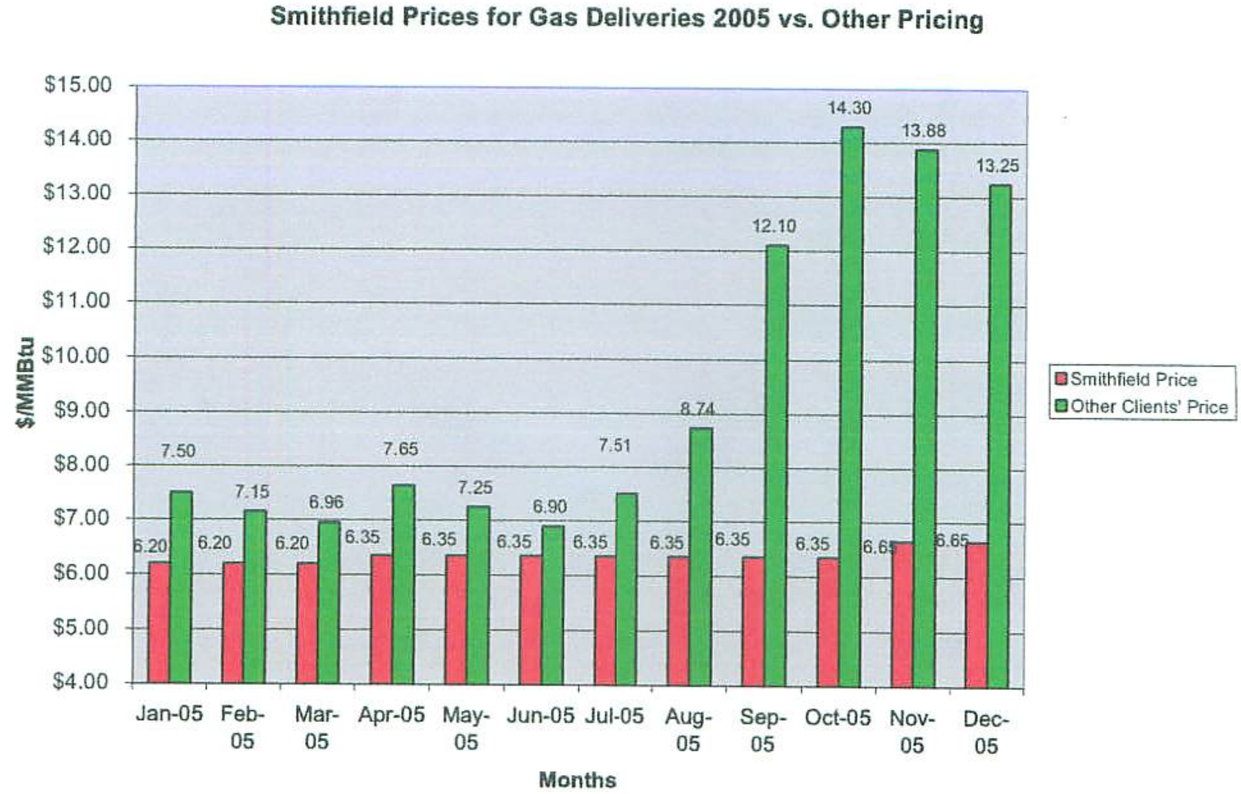
To determine the fair market value of the gas that was actually sold to Smithfield by NGD, it is necessary to look at the prices charged to and paid by the Other Clients. This valuation should include a weighted (including the applicable volumes delivered to Smithfield) comparison by month.

First, I examined the Smithfield Prices by month in comparison to the market low, market high, and the Other Clients' Price.



It is obvious that Smithfield's price was below each of these price indicators for each month, for pricing detail by month, see the attached worksheet "Smithfield Pricing Details.xls", "Vols and Price Discounts Sum" tab.[40] A logical approach is to compare Smithfield's prices only to those given to the Other Clients.

[40] Please see attached worksheet, as listed in documentation Index.



I considered the prices paid by Other Clients' to be fair market value for physical gas deliveries for natural gas each month, from January to December 2005. Thus, the Debtor was not receiving fair market value for gas sold to Smithfield each month.

Smithfield did pay some amount for the gas each month, based upon this non-market pricing. To view the total amount still outstanding to recover reasonably equivalent value, it is necessary to look at the weighted average cost of gas (WACOG) paid each month by Smithfield versus the WACOG that would have been applicable using the Other Clients' average price by month. WACOG is calculated by taking the all the prices of the natural gas times the volume delivered under that pricing agreement. Then the total dollar amount is divided by the total volume delivered, to get the weighted average cost of gas per time period.

For example: To Customer A in January, 10,000 MMBtu was delivered at $5.00 and 2,500 MMBtu was delivered at 6.06. To get Customer A's WACOG for January, the following calculation would be performed:

10,000 x \$5.00 = \$50,000

2,500 x 6.06 = \$15, 250

Total Due for Gas for January

\$65, 250.

WACOG for Jan = \$65,250/12,500 (total vol) = **\$5.21**

For details on Smithfield's WACOG for Jan-Nov 2005 vs. Other Clients' WACOG, see the following table. (All volumes assume Smithfield's actual delivered volumes.)

Delivery Month 2005	Volumes Delivered to Smithfield (MMBtu)	Smithfield WACOG Price	Total Amount Paid (volume x price)	Other Clients' Average Price	Amount to be Paid at Other Clients' Price	Underpayment (Total Paid – Amount at OC Price)
Jan	74,817.70	\$6.20	\$463,869.74	\$7.50	\$560,881.85	(\$97,012.11)
Feb	68,830.40	\$6.20	\$426,748.48	\$7.15	\$492,436.76	(\$65,688.28)
Mar	74,031.20	\$6.20	\$458,993.44	\$6.96	\$515,425.84	(\$56,432.40)
Apr	61,907.60	\$6.35	\$393,113.26	\$7.65	\$473,473.32	(\$80,360.06)
May	62,043.20	\$6.35	\$393,974.32	\$7.25	\$449,875.08	(\$55,900.76)
Jun	62,434.30	\$6.35	\$396,457.81	\$6.90	\$430,861.91	(\$34,404.10)
Jul	63,200.20	\$6.35	\$401,321.27	\$7.51	\$474,772.54	(\$73,451.27)
Aug	74,928.90	\$6.35	\$475,798.52	\$8.74	\$654,864.54	(\$179,066.02)
Sep	62,985.30	\$6.35	\$399,956.66	\$12.10	\$762,212.64	(\$362,255.99)
Oct	71,378.70	\$6.35	\$453,254.75	\$14.30	\$1,020,911.99	(\$567,657.25)
Nov	63,561.10	\$6.65	\$422,681.32	\$13.88	\$882,479.44	(\$459,798.12)
Dec	10,464.00	*\$6.65*	**\$0.00**	\$13.25	\$138,644.68	(\$138,644.68)
TOTALS	**750,582.60**	**\$6.24**	**\$4,686,169.55**	**\$9.14**	**\$6,856,840.59**	**(\$2,170,671.05)**

[Smithfield was not billed for December 2005 gas by NGD or the Trustee; however, Smithfield may have paid imbalance charges to Piedmont Natural Gas with respect to the gas supplied during December 1-8, 2005 and if so, Smithfield would be entitled to a credit in such amount.]

6.0 Reservation of Rights and Compensation Disclosure

Although my study is based upon the currently available record produced in connection with this lawsuit, and I am in a position to render my opinions at this time based upon such information, my study is ongoing. Accordingly, I reserve the right to revise or expand my expert opinions to reflect any additional opinions I may formulate based upon newly acquired information or arising from reflection and reconsideration of the opinions based upon views expressed by expert witnesses, if any, and upon further study and information, including, among other things, documentary and testimonial evidence introduced.

GSC charges $200 per hour for my professional services in this matter, subject to review and approval by the Bankruptcy Court after notice and hearing.

This report is not to be reproduced, distributed, disclosed or used for any purposes other than the above-referenced litigation without my prior approval.

APPENDIX 1

Claire P. Gotham

GSC Energy, Inc.
(404) 889-0652
Claire@hedger.com

HIGHLIGHTS

- Experience in multiple areas of energy industry, including retail end-users, utilities, & wholesale trading
- Extensive skills & experience in client relations, negotiations, & account management
- Recognized speaker, with proven experience in leading large seminars on energy-related issues

Relevant Professional Experience

GSC Energy, Inc., Atlanta, GA
05/06 to Present

President

- Oversee all day to day duties involved in developing & managing consulting business
- Develop and execute marketing plan for new business lines
- Teach energy risk management seminars across the country including:
  - *FAS 133 Derivative & Hedge Accounting*
  - *Natural Gas Hedging 101*
  - *Advanced Natural Gas Hedging and Deal Structure*
- Develop service offerings and perform market research

Deloitte & Touche, Los Angeles, CA
09/05 - 05/06

Senior Consultant

- Performed various duties as a subject matter expert in the following areas:
  - Risk analysis and management concepts and practices
  - Internal controls related to the trade life cycle (including front, middle, and back office functions)
  - Specific deregulated regional energy markets
  - Regulatory issues affecting deregulated wholesale energy markets
  - Fundamental analysis of physical energy markets
- Developed service offerings and performed market research
- Reviewed and analyzed clients risk management policies and procedures

Independent Consultant, Los Angeles, CA
06/02 to 09/05

- Development & execution of risk management strategies, such as physical or financial hedges
- Analysis of energy market fundamentals & current events
- Provide current & forward pricing for various natural gas markets, at both citygates & burnertips
- Trading of natural gas, both physical & financial
- Review, validate & update current energy information infrastructure
- Manage all operational issues, from physical flow to contract negotiations

PacifiCorp Power Marketing, Portland, OR
06/01 to 06/02

Lead/Senior Gas Trader

- Developed & executed monthly trading strategy around company's fuel supply requirements for generation projects
- Managed strategy daily by monitoring market activity, risk management system reports, & power-trading
- Participated in the development of intermediate & long-term fuel supply strategies
- Executed gas trades for all spark spread transactions, both speculative & for asset management
- Executed trades for proprietary trading book, with company set profit goals & stop losses
- Continuously monitored market for capacity opportunities, forward basis markets for spread & basis hedging opportunities, & the NYMEX for price hedging opportunities
- Reported daily to entire trading group on EIA/AGA storage developments & market impact
- Monitored & evaluated all regulatory proceedings & rulings, & advised on business impact

Sempra Energy Solutions, Los Angeles, CA
10/99 to 1/01

Natural Gas Portfolio Manager

- Developed portfolio strategy of natural gas supply & delivery for 200+ industrial/commercial retail accounts
- Negotiated pricing & supply agreements for term & immediate supply needs
- Hedged transactions to lock in margins & to manage price risk, utilizing derivatives
- Managed imbalances through trading & storage on six separate delivery systems in the West, core & non-core
- Managed storage injections & withdrawals to maximize operational flexibility & capture seasonal price variations
- Developed & implemented strategy for product design & pricing which allowed company to earn margin & offer competitive products while minimizing risk
- Executed daily to multi-year energy usage forecasts for retail customers
- Generated offers for fixed prices, caps, floors, collars, & index based pricing for national sales force
- Created & authored daily e-newsletters to customers, detailing prices, market outlook & recommendations

Cook Inlet Energy Supply, Los Angeles, CA 9/98 to 10/99

Manager, Transportation & Exchange

- Traded physical & financial natural gas in Canada, the Pacific Northwest, California, & Rockies, including futures, swaps, & options
- Purchased/Sold spot natural gas to maximize monthly positions & to increase revenue
- Negotiated pricing with other marketing firms & financial brokers for long term deals
- Supervised scheduling, nominating, dispatching gas on a daily & intra-day basis, resolving allocations & imbalances

- Researched & recommended strategy regarding natural gas storage/transportation projects, & regulatory issues
- Acquired & coordinated the acquisition of gas transportation, including released capacity
- Composed & presented transportation & storage analysis for potential buyers, during corporate sale process
- Represented CIES as a speaker at energy industry trade shows, customer meetings, & conferences

Pacific Gas & Electric Company, San Francisco, CA 9/96 - 9/98

Product Management/ Product Development

- Responsible for all parts of product process: concept development, program policies, market introduction, product management, & contract negotiation
- Led cross-functional teams to create & launch new products, with operational, financial, regulatory considerations
- Developed product enhancements based on market knowledge, customer segmentation, & market research
- Planned & led all sales force training for new or upgraded products
- Organized & executed customer focus groups in various cities

Sales & Service

- Negotiated & executed short/long term storage, hub services & transportation deals for California pipeline
- Developed pricing decisions through understanding of market issues & identification of financial opportunities
- Researched these opportunities, as well as competitive options & provided analysis to department heads
- Gathered, managed, & communicated market intelligence throughout department via E-mail & Lotus Notes database
- Coordinated sales activities with Product Management & Market Relations to ensure sales goals were achieved

GSC Energy, Atlanta, GA 8/94 - 8/96

Energy Futures Trader

- Obtained **Series 3** license & registration with the NFA & the CFTC
- Order execution of NYMEX energy futures contracts
- Assisted with the development of risk management & hedge programs for clients, utilizing various derivatives
- Researched & evaluated current data regarding risk management incentive mechanisms utilized by public utilities
- Created & implemented new marketing strategies for GSC Energy daily publications
- Qualified & pursued sales leads for consulting group generated by risk management workshops held across the U.S. & Canada

EDUCATION & QUALIFICATIONS

Bachelor of Arts in Anthropology & Spanish, *Cum Laude* TULANE UNIVERSITY, New Orleans, LA

Fluency in Spanish

APPENDIX 2

Particular Documents Reviewed and/or Relied On and/or Which May Be Used As a Summary or Support for My Opinions

1. Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 4
2. Pricing data from Platts' publications "Inside FERC's Gas Market Report" published monthly.
3. Pricing data from DTN Prophet X quote system. Also available directly from NYMEX at NYMEX.com.
4. www.noaanews.noaa.gov
5. Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 2
6. http://www.eia.doe.govloiaflservicerptlderivative/index.html
7. FASB Statement no. 133 as amended and interpreted "Accounting for Derivatives and Hedging Activities"
8. ISDA master agreement sample
9. NAESB master agreement sample
10. http://www.williams.com/productservices/gaspipelines/naturalgas.asp#transco
11. http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm, U.S. Natural Gas Deliveries to Electric Power Consumers (MMcf)
12. http://tonto.eia.doe.gov/dnav/ng/hist/n9140us2A.htm, U.S. Natural Gas Total Consumption
13. http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/reloilgaspri/reloilgaspri.pdf - "The Relationship Between Crude Oil and Natural Gas Prices" by Jose A. Villar, Natural Gas Division, Energy Information Administration and Frederick L. Joutz, Department of Economics, The George Washington University, October 2006
14. http://tonto.eia.doe.gov/dnav/ng/hist/n9050us2A.htm - Annual History of U.S. Marketed Production (MMcf)
15. http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm - U.S. Natural Gas Citygate Price, EIA
16. http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3M.htm - U.S. Natural Gas Wellhead Price, EIA
17. Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 4
18. Pricing data from Platts' publications "Inside FERC's Gas Market Report" published monthly. See documents list for details.
19. Pricing data from DTN Prophet X quote system. Also available directly from NYMEX at NYMEX.com.
20. www. noaanews.noaa.gov
21. Energy Information Administration/Short-Term Energy Outlook- August 2005, p. 2
22. All statistics regarding Hurricane Katrina's effect on energy production and refining come from the DOE, included in statements made to Congress on October 27, 2005 by Energy Secretary Bodman. Testimony transcript available at www.doe.gov
23. All statistics regarding Hurricane Rita's effect on energy production and refining come from the DOE, included in statements made to Congress on October 27, 2005 by Energy Secretary Bodman. Testimony transcript available at www.doe.gov
24. Platts Pricing Methodology
25. Attached prices, published by Platts for 2005
26. Rates and Tariffs, Transcontinental Pipeline Company, from www.gaspipeline.williams.com
27. "Smithfield Pricing Detail.xls"
28. "NGD Price History.xls"
29. "NGD 2005 Price Discounts Vs. Markets.xls"
30. "NGD Price Discounts vs. Market.xls"
31. "NGD book1.xls"
32. "NGD Other Clients Invoices.xls"
33. "November 2005 Mid-month Billing.xls"

34. "January '2005 P&L.xls"
35. "February '2005 P&L.xls"
36. "March '2005 P&L.xls"
37. "April '2005 P&L.xls"
38. "May '2005 P&L.xls"
39. "June '2005 P&L.xls"
40. "July '2005 P&L.xls"
41. "August '2005 P&L.xls"
42. "September '2005 P&L.xls"
43. "October '2005 P&L.xls"
44. "November '2005 P&L.xls"
45. "January 2005 Billing Info.xls"
46. "February 2005 Billing Info.xls"
47. "March 2005 Billing Info.xls"
48. "April 2005 Billing Info.xls"
49. "May 2005 Billing Info.xls"
50. "June 2005 Billing Info.xls"
51. "July 2005 Billing Info.xls"
52. "August 2005 Billing Info.xls"
53. "Sep 2005 Billing Info.xls"
54. "Oct 2005 Billing Info.xls"
55. "Nov 2005 Billing Info.xls"
56. : "Oct 2005 Billing Info.xls"
57. "Affidavit of Bob Miller.pdf"
58. "Smithfield Foods Contract.pdf"
59. "Pages 3-5 from Smithfield info.pdf"
60. "Draft-Smithfield memo in support of Motion to Dismiss.pdf"

APPENDIX 3

Henry Hub Natural Gas Futures

Trading Unit

10,000 million British thermal units (mmBtu).

Price Quotation

U.S. dollars and cents per mmBtu.

Trading Hours ***(All times are New York time)***

Open outcry trading is conducted from 9:00 AM until 2:30 PM.

Electronic trading is conducted from 6:00 PM until 5:15 PM via the CME Globex® trading platform, Sunday through Friday. There is a 45-minute break each day between 5:15PM (current trade date) and 6:00 PM (next trade date).

Trading Months

The current year and the next five years. A new calendar year will be added following the termination of trading in the December contract of the current year.

Trading at Settlement (TAS)

Trading at settlement is available for the front two months except on the last trading day and is subject to the existing TAS rules. Trading in all TAS products will cease daily at 2:30 PM Eastern Time. The TAS products will trade off of a "Base Price" of 100 to create a differential (plus or minus) in points off settlement in the underlying cleared product on a 1 to 1 basis. A trade done at the Base Price of 100 will correspond to a "traditional" TAS trade which will clear exactly at the final settlement price of the day.

Minimum Price Fluctuation

$0.001 (0.1¢) per mmBtu ($10.00 per contract).

Maximum Daily Price Fluctuation

$3.00 per mmBtu ($30,000 per contract) for all months. If any contract is traded, bid, or offered at the limit for five minutes, trading is halted for five minutes. When trading resumes, the limit is expanded by $3.00 per mmBtu in either direction. If another halt were triggered, the market would continue to be expanded by $3.00 per mmBtu in either direction after each successive five-minute trading halt. There will be no maximum price fluctuation limits during any one trading session.

Last Trading Day

Trading terminates three business days prior to the first calendar day of the delivery month.

Settlement Type

Physical.

Delivery

The Sabine Pipe Line Co. Henry Hub in Louisiana. Seller is responsible for the movement of the gas through the Hub; the buyer, from the Hub. The Hub fee will be paid by seller.

Complete delivery rules and provisions are detailed in Chapter 220 of the Exchange Rulebook.

Delivery Period

Delivery shall take place no earlier than the first calendar day of the delivery month and shall be completed no later than the last calendar day of the delivery month. All deliveries shall be made at as uniform as possible an hourly and daily rate of flow over the course of the delivery month.

Alternate Delivery Procedure (ADP)

An alternate delivery procedure is available to buyers and sellers who have been matched by the Exchange subsequent to the termination of trading in the spot month contract. If buyer and seller agree to consummate delivery under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the Exchange.

Exchange of Futures for Physicals (EFP) or Swaps (EFS)

The commercial buyer or seller may exchange a futures position for a physical position or a swaps position of equal quantity by submitting a notice to the Exchange. EFPs and EFSs may be used to either initiate or liquidate a futures position.

Grade and Quality Specifications

Pipeline specifications in effect at time of delivery.

Position Accountability Levels and Limits

Any one month/all months: 12,000 net futures, but not to exceed 1,000 in the last three days of trading in the spot month.

Margin Requirements

Margins are required for open futures positions.

Trading Symbol

NG
NGT (TAS Code)

APPENDIX 4

Henry Hub Natural Gas Futures Prices

11/28/2005	11.600	11.610	10.880	11.180	Dec '05 exp
10/27/2005	13.700	13.950	13.300	13.832	Nov '05 exp
9/28/2005	12.670	14.800	12.670	13.907	Oct '05 exp
8/29/2005	11.200	11.700	10.650	10.847	Sep '05 exp
7/27/2005	7.415	7.670	7.400	7.647	Aug '05 exp
6/28/2005	6.980	7.110	6.900	6.976	Jul '05 exp
5/26/2005	6.270	6.290	6.030	6.123	Jun '05 exp
4/27/2005	7.120	7.140	6.680	6.748	May '05 exp
3/29/2005	6.980	7.400	6.960	7.323	Apr '05 exp
2/24/2005	6.390	6.500	6.250	6.304	Mar '05 exp
1/27/2005	6.460	6.550	6.250	6.288	Feb '05 exp
12/28/2004	6.180	6.340	6.160	6.213	Jan '05 exp