New York Mercantile Exchange

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Risk Management with Natural Gas Futures and Options

Introduction

A Maturing Market

U.S. natural gas markets have undergone a remarkable transformation in recent years. After decades of rigid regulation, the natural gas industry is now free to compete on the wholesale level and, in a growing number of states, at the retail level. The result has been a substantial increase in the production of natural gas, far-reaching changes in the structure of the industry, and the growth of a large and fluid market in natural gas futures and options to cope with pricing uncertainties. In coming years, promising new technology which can change natural gas into easily transportable oil products may transform the industry once again.

Prior to the enactment of the Natural Gas Policy Act of 1978, the price of gas in the interstate market was stable all along the distribution chain. Interstate market sales were subject to government oversight regarding prices, supplies, and vendor-customer relations at every step of the way, from wellhead to burnertip. Producers and distributors faced real risks, but not the challenges of competition.

The extensive regulations were intended to protect consumers by ensuring adequate supplies at fair prices. By the mid 1970s, however, the regulations were no longer doing the job. An acute supply shortage had developed, demonstrating that government regulation was not accomplishing its objective. Believing that competition in a free market was a superior alternative, Congress enacted the Natural Gas Policy Act of 1978, with the major feature of phased decontrol of wellhead prices.

Price decontrol was not sufficient, however, to ensure a free market because, at the time, natural gas pipelines had no obligation to transport gas they did not own. This led the Federal Energy Regulatory Commission to implement rules making it attractive for pipelines to transport gas for third parties.

That decision was the key step in creating a free market. It was only then that the growing supply of gas flowing in response to free market pricing at the wellhead, along with the ability to move that gas where desired, led to increased competition and the expansion of spot market transactions. Increased competition, in turn, led to considerable changes within the industry and to the start of trading in natural gas futures.

Marketers — A New Class of Market Participant

One outgrowth of the new competitive environment was the rise of a new class of participant in the industry — the marketer. In earlier years, when the gas industry was regulated and prices closely controlled, there was no opportunity for competitive pricing or market innovation. Deregulation changed that. Marketers stepped in, functioning as wholesalers, brokers, and aggregators. They purchase gas from producers and find buyers, or they obtain purchase commitments and find sellers. Sometimes, they simply broker the gas. Other times, they pull together or aggregate enough end-users such as gas utilities (also known as local distribution companies or LDCs) so that they can negotiate lower prices based on volume. Frequently, they arrange transportation of the gas as well. Accordingly, they serve an important role in adding liquidity to the market, particularly for smaller producers and industrial consumers.

Another outgrowth of the new competitive market for gas was the need for futures and options trading to cope with the price uncertainty of a free market. Price uncertainty creates risks and opportunities. Futures and options markets provide a forum for commercial interests in a commodity to hedge against price risk by transferring that risk to those more willing and able to bear it, or to those commercial interests with inverse risk profiles. What's more, an active futures market provides a readily available, widely accepted reference price for the underlying commodity, thereby improving the efficiency of the overall market.

The New York Mercantile Exchange worked with a team of natural gas industry representatives to develop natural gas futures and options that address the needs of the industry and are attractive to investors. Within a few short years of the launch of the world's first natural gas futures contract in April 1990, futures became an integral part of the business for market participants from all sectors of the gas industry — from producers to end-users. Eventually the futures contract allowed the Exchange to provide the industry with another risk management tool — a natural gas options contract.

This brochure provides an overview of the natural gas market, an explanation of the risks faced by the various market participants, a review of some of the ways futures and options can be used to manage these risks, and, as an insert in the back cover, an updated summary of contract specifications.

The development of the spot market is probably the best measure of the radical structural change that has swept this industry. In 1982, a spot market for natural gas hardly existed; by the late 1980s, it accounted for about 80% of the entire gas market. By 1992, spot transactions had fallen back to 35% to 40% of the overall market. This is a healthy development because spot markets act as price setters at the margin, while long-term contracts generally provide for more stable pricing over time. Unlike their predecessors, however, the new generation of long-term contracts generally are not fixed-price contracts; they commonly provide for some form of price indexing, the foundation of which is the spot market.

The spot market also acts as a default market. If one party to a long-term contract is unable to buy or sell the required quantity of gas in any month, his counterparty knows there is a market outlet to which he can temporarily turn.

Another important measure of the strength of the free gas market is the growth of pipeline contract carriage — shipments of gas in which the pipelines simply act as transportation agents and have no equity stake in the gas. In 1983, only 5% of the gas that interstate pipelines delivered was contract carriage gas; the rest was their own. A decade later, contract carriage comprised almost 90% of pipeline deliveries. The figure today is 100%.

In July 1989, President Bush signed a gas price-decontrol bill that finally ended 35 years of wellhead price controls although, for all practical purposes, those price controls already had little influence on the market by then. In 1992, FERC issued Order 636 which effectively unbundled interstate pipeline transportation services from all other services the pipeline companies might offer, and forbade discrimination among shippers. Among other things, this created a secondary market in pipeline capacity, making the transportation of gas a more important component of end price.

The transition from total regulation to free-market competition is now complete at the wholesale level and taking place at the retail level in more and more states where small commercial and residential customers are being offered "open access" to competitive gas suppliers.

Growth Anticipated, but Competitive Risks Continue

Natural gas is an attractive fuel: it burns cleanly, producing little pollution, and its reserves are abundant. The deregulation that began in 1978 has addressed two important factors that were inhibiting the growth of the industry: the lack of incentive to drill for new supplies, and the lack of reliable, readily accessible transportation.

Two other subsequent developments have given natural gas consumption a boost. The 1990 amendments to the Clean Air Act have led utilities and industries to use more natural gas in place of the high-sulfur boiler fuels that contribute to acid rain. The other is the nation's rising demand for electricity. Utilities are responding by building or contracting for new combined-cycle and cogeneration facilities, most of which are fueled by natural gas. In coming years, natural gas may also become a principal fuel for the fuel cell technology now emerging as a viable alternative to the internal combustion engine.

The gas industry faces uncertainties, too, including competition from oil. Some of the country's largest natural gas consumers have the ability to switch fuels easily, so natural gas suppliers must compete with the fuel oil market as well as with each other. While gas prices may have to remain relatively low to stay competitive, producers will not be motivated to drill for new supplies unless prices seem likely to rise in the future. And, if drilling does not pick up, current and potential consumers may shy away from the market out of concern that supply shortages could reoccur. At the same time, technological break-throughs in converting gas to liquids, which are easier to transport, may ultimately bring more gas-based fuels to the market.

Deregulation has opened the industry to both the opportunities and the risks of competition.

U.S. Natural Gas Supply and Demand Schedule

A recent U.S. Department of Energy study notes that natural gas production in the lower 48 states can be increased at substantially lower cost than was anticipated only a few years ago. Not only has the U.S. Geological Survey raised its estimate of the reserve base, but new and better technology has made it easier to extract more gas from wells at less cost. The Energy Department's study puts recoverable reserves and resources of natural gas in the lower 48 states at 1,310 trillion cubic feet, more than a 69-year supply at current production levels. Most of these reserves are recoverable at prices below $3.50 per 1,000 cubic feet, so the country is in no danger of running out of natural gas any time soon.

Most U.S. gas demand is met by domestic production. In 1997, 13.6% of U.S. natural gas consumption was met by imports, virtually all arriving by pipeline from Canada. The low level of U.S. imports is typical of the natural gas markets worldwide. While nearly 50% of world oil production crosses a country's borders, only 16% of the world's gas production does so. But world gas trade is growing. The United States imports relatively small amounts of liquefied natural gas, but this could grow in the future. At the same time, the United States exports liquified natural gas (LNG) from Alaska to Japan, and exports small, but growing, quantities of gas to Mexico.

Natural gas accounts for 24.9% of primary energy consumption in the United States. Consumption in 1997 totaled 21,898 billion cubic feet. Different types of natural gas users have different consumption patterns. End-users are generally grouped as residential, commercial, industrial, and power generators; each has its own risk profile.

Share of Total Gas Demand - 1997

Residential	22.9%
Commercial	14.7%
Industrial	40.0%
Electric power producers	13.5%
Lease, plant, and pipeline fuel	8.9%

Source: Monthly Energy Review, U.S. Department of Energy

Risk Profile: Residential and Commercial Users

The residential and commercial groups have fairly stable baseload demands and large, variable heating demands. This heating demand is the main force that drives the natural gas market during the winter; approximately 43% of the natural gas consumed throughout the year is actually used in the four-month period of December through March.

Over the short term, residential and commercial heating demand is weather-sensitive, varying primarily in response to the severity of the winter temperatures. Demand can also be affected if there is a large change in the absolute price level of gas, causing consumers to adjust their thermostats. Over the longer term, heating demand will change according to the number of housing starts, the relative costs of alternative heating systems, and the availability of pipeline capacity. In market terminology, these users are the "longs" in the market.

Demand can also be affected by changes in the relative prices among fuels. But home-owners or commercial property managers must typically be convinced that the price difference is large and permanent before they will consider installing new heating systems. Exceptions are those commercial customers whose consumption is large enough for an investment in dual-fuel capacity to be practical.

Industrial Consumers and Electricity Producers

Many manufacturers consume natural gas, both as a feedstock and as a fuel for their manufacturing process. Generally, there is no other fuel that can be used for these purposes, or else the potential substitutes are costly, so this portion of industrial demand is not sensitive to residual fuel oil prices. However, both processing demand and boiler fuel demand are sensitive to changing levels of industrial activity — especially in the glass, food, paper, chemical, petroleum refining, primary metals, fabricated metals, and machinery industries. They are all subject to forces within their own markets that can affect their gas usage.

For most electric utilities, air conditioning use is the major variable in market demand for electricity, and more and more power producers depend upon gas to meet peak demand. Since electricity demand peaks in the summer in most of the country, consumption of gas by electric power producers is counter-seasonal, helping to some extent to smooth out the highly seasonal demand pattern set by residential and commercial heating users.

In much of the United States, any planned expansion in generating capacity is likely to be gas-fired, making electric power generation the major growth market for the next several years. New combined-cycle generating facilities are less capital-intensive than coal, nuclear, or renewable electricity plants. More gas-fired plants are also likely to be built to replace aging nuclear power stations. The electric utility industry estimates that, by the year 2007, the amount of power generated by natural gas will grow by almost 65%. The gas portion of overall generation will increase to 12% by 2007 from 9.1% in 1997.

A growing number of refineries, petrochemical plants, and other industrial facilities that use natural gas to generate electricity for their own needs frequently sell excess electricity to local utilities and power marketers. Known in the power industry as "co-generators," many have contracts to supply long-term, interruptible power. Their reliance on natural gas supplies and their exposure to gas prices can have considerable impact on their earnings profile.

How Futures and Options Can Help You

U.S. natural gas prices are now largely determined by the forces of supply and demand. Technical factors, such as pipeline capacity, as well as fundamental factors, such as industrial use, influence prices. Price risk and competition have also been driven all the way from producers to resellers to the retail level. In some parts of the country, for example, homeowners now have the opportunity to lock in prices through long-term contracts.

Meanwhile, now that wellhead prices are no longer set by regulators, the futures market has become the major universally disseminated reference price for natural gas. Prices are posted virtually instantaneously, giving buyers and sellers a real-time view of market conditions, including trading volume. The futures contract also facilitates the pricing of many other gas transactions — including those in which neither party actually uses futures — by serving as a price reference index, or as a benchmark to evaluate the competitiveness of short- and long-term deals.

The futures market allows industry marketers to lock in a purchase price for gas they have committed to deliver, or to lock in a selling price, including a profit margin, for gas they have committed to buy. Other market participants have also been able to lock in purchase or sale prices without assuming the risks of a fixed-price contract. The market is a liquid one, giving participants the ability to enter and exit positions readily without disrupting prices in the broader market.

Pricing in a volatile market makes it difficult to maintain flexibility when planning. Without futures, market participants must accept fixed-price contracts, which can prove disadvantageous, as New York State regulators learned in 1997 when they placed price caps on gas sold through local distribution companies. The futures market provides flexibility in forward planning. This flexibility is further enhanced by the options market which provides participants with, among other things, the ability to set price floors or ceilings, hedging against adverse price movements while retaining the ability to participate in favorable ones.

Let's look more specifically at some of the ways futures and options are used to address the needs and risks of six important groups: producers, gas processors, interstate pipeline companies, local distribution companies (or LDCs), marketers, and end-users. Even those companies choosing not to use futures or options can benefit from the price discovery offered by futures markets by tying the price of their cash market transactions to the futures price.

Producers

The gas industry has evolved from a stable environment in which a producer could expect to sell any gas he found to one that has had a persistent surplus for many years. Although supply and demand now appear to be fairly well balanced, there is still a risk of seasonal as well as long-term downturns in price. New York Mercantile Exchange futures and options can help mitigate the new risks faced by producers. For example:

- When abnormal weather, concerns about storage levels, or other factors cause natural gas spot prices to strengthen, that strength will frequently be reflected in prices paid for futures contracts deliverable some months ahead. This presents opportunities to lock in attractive forward selling prices. Producers who sold futures contracts during the period of supply restrictions following Hurricane Andrew in 1992 could have achieved effective gas prices of $2.50 and $2.15 for their January and February 1993 production, respectively, both about 50¢ higher than actual spot prices for those months.

- The natural optimism of producers can make the decision to lock in a price a difficult one with the inability to participate in price increases above that level. At times when prices are comfortably high but further upside movement is a reasonable expectation, producers may prefer to set a price floor rather than a price level. This can be accomplished by purchasing put options.

- Producers can earn additional revenue in flat markets by selling call options on their reserves.

- In general, financial institutions are more willing to lend against hedged reserves than unhedged reserves and, in some cases, hedging is a prerequisite for borrowing. Either the sale of futures or a put options purchase is considered a suitable instrument for hedging gas still in the ground.

Gas Processors and Refiners

Natural gas processors, positioned between the producers and the pipelines, provide a valuable service by making the gas suitable for shipment by pipeline. The processors take the "wet" natural gas as it comes from the well, extract propane, butane, and other liquids, and send the resulting "dry" gas to pipelines for shipment to market.

Gas processors account for about half of U.S. propane supply and about three quarters of total U.S. liquefied petroleum gas (LPG) supply, which also includes ethane, butane, isobutane, and natural gasoline.

Processors are often affiliated with natural gas producers or pipelines, but typically established as separate operating units. There is also an independent segment of the industry whose primary business is gas processing.

Even though LPG is derived from natural gas, the markets are different and therefore prices often move independently. Gas processors can use natural gas and propane futures to hedge the price risk of processing gas to extract propane. For example,

- Natural gas processors who buy natural gas and sell propane at spot market prices can use the fractionation or "frac" spread to lock in attractive processing margins. To hedge, a processor would buy natural gas futures and sell a Btu-equivalent number of propane futures. Should the fractionation margin narrow, the gas processor will have an offsetting gain on his frac spread.

- Processors who want to expand their market share by offering customers fixed price contracts for propane can still ensure attractive margins by purchasing natural gas futures to lock in their input cost.

- Conversely, gas processors offered attractive natural gas purchase contracts can sell propane futures to lock in a fractionation margin.

Interstate Pipelines

In years past, interstate pipelines tended to be both transportation companies and gas merchants. They not only transported gas, but bought the gas and then negotiated a delivery price with their customers. In the wake of the FERC order that deregulated the pipeline business and the rise of new marketers in the gas industry, interstate pipeline companies have increasingly focused solely on the transportation side of their business. Their role as merchants who bought gas at one end of the pipeline and sold it at the delivery point has declined sharply — or else is conducted through separate business units operating at arm's length from the transportation business. Today, pipeline companies operate more like railroad or trucking companies which transport goods but do not own those goods.

Even without their merchant's role, however, pipelines can still be subject to occasional pricing risk, especially when a competing pipeline can deliver gas to a common market area at a lower price. Or the pipeline may find itself in a situation where an alternative fuel, such as oil, is less expensive, and the cost of gas transportation is a critical factor in determining the competitiveness of the delivered price of gas. In that event, the pipeline could employ an intermarket spread.

Local Distribution Companies

Local distribution companies (LDCs), the gas utilities, have evolved into aggressive purchasers and marketers and, to a growing degree, transporters. They are beginning to emerge as one of the more significant forces in the natural gas industry. Many, in fact, have created separate marketing companies which buy and sell gas for other LDCs. In states which now permit competition to supply gas to residential customers, numerous LDCs are competing with each other for retail business.

When it comes to obtaining supplies, LDCs have choices. They can purchase gas from producers or marketers; they can buy at spot prices; or they can negotiate short-, medium- or long-term contracts. However, since many of an LDC's larger customers may also have access to all of these supply possibilities, the LDC must be nimble if it intends to be a competitive merchant of natural gas.

LDCs are also exposed to interfuel competition, and this risk can loom large when industrial users and electric utilities form a significant part of the LDC's business.

Before an LDC can consider any hedge, however, it will want to be assured that its public service commission will allow hedge gains and losses to be equally offset against gas acquisition costs. In states which have adopted this policy, LDCs can use futures and options to maintain price flexibility in a variety of ways:

- Just as a strong spot market will tend to strengthen futures prices for several months ahead, creating an opportunity for producers to lock in delivery prices, so too will a soft market afford buying opportunities for LDCs. By having purchased April, May, and June futures in February 1993, for example, LDCs could have lowered their average gas acquisition costs by about 50¢ per million Btus.

- Although an LDC may have an agreement with its state regulatory agency that hedge losses will be treated the same as hedge gains, a large decline in spot prices leaving the LDC locked into prices well in excess of the market could create a politically awkward situation for both the LDC and the public service commission. Should the risk of a large downward price move be considered significant, it may be preferable for the LDC to purchase call options to set a ceiling price for its gas purchases.

- LDCs concerned about their ability to recover the cost of storage gas in a competitive market could use a short futures or long put options position, or could even sell options calls to recover some of the cost. In July, for example, the North Shore Gas Company calculates expected gas demand for August, September, and October and realizes that it will have very high storage costs because demand will be low. To offset its costs, the company buys futures and then sells puts — which give it the right but not the obligation to sell the underlying futures contract — in November. If prices have risen by November, as expected, the company can recoup its storage costs by the profit on the puts, and then replace its supply at current prices.

- To compete with producers and marketers for gas sales to their highly price-sensitive customers, some LDCs are now offering futures- and options-based pricing alternatives.

- Whether acting as supplier or simply transporter to a dual-fuel capable customer, an LDC is at risk from falling oil prices. By using a long natural gas/short crude oil spread, the company could potentially maintain the competitiveness of its delivered price.

Marketers

As natural gas market participants become increasingly sophisticated, marketers are coming under greater pressure to provide added value. Marketers are in the unusual position of competing with their own clients. Producers, LDCs, and end-users sometimes deal with one another directly, so marketers must offer innovative pricing and risk management ideas in order to attract business. Marketers must also cope with the high level of risk that comes with being an intermediary, exposed on both the buy and sell sides. In fact, even when a marketer manages to negotiate both sides of a transaction at the same time, chances are good that the price index or the contract timing will not be a perfect match, and the marketer will have some remaining risk to manage.

Marketers can use natural gas futures and options in a variety of ways. They provide flexibility in forward planning, which is the key to an effective marketing strategy. For example, here is how a marketer could use futures to provide "added value" to a client, enabling him to lock in the current spot price:

Assume an LDC would like to lock in the current spot price for a three-month supply of gas, and a marketer agrees to provide the gas at that price plus a marketer's fee. To acquire the gas, the marketer contracts with a producer for a three-month supply at spot prices, which are going to vary over the period. At the same time, the marketer hedges by purchasing futures with corresponding delivery months. If spot prices increase during the three months, the gains in the futures contracts can offset the increased expense of the gas. The marketer can provide gas to the LDC at the agreed-upon price without the risk of losing money if prices actually rise during the period.

A growing number of gas buyers and sellers are interested in using gas price ceilings or floors, but at times do not wish to pay the implicit or explicit options premium associated with these arrangements. Many marketers are therefore offering their customers so-called costless collars (more accurately called no-premium collars since there is an opportunity cost associated with their use).

Collars allow the reduction or elimination of the options premium by trading off participation in a favorable price move beyond a certain level. For market participants who expect prices to remain within a trading range yet need some protection against an adverse move, collars have considerable appeal and constitute an effective competitive tool for gas marketers.

Marketers can also hedge against risks they face in their normal course of business:

- Assume a marketer has purchased gas from a producer but has not yet struck a deal with any buyers. The marketer is concerned that prices may fall before he can sell the gas, so he sells futures to lock in his sale price.

A marketer has agreed to sell natural gas to a chemical company at the spot price plus a transportation charge and marketer's fee. The marketer has not secured supplies, and is concerned that the market may tighten, forcing him to buy at higher prices. He buys futures to lock in his purchase price.

End-Users

Large industrial consumers often have a myriad of suppliers to choose from and some possess the ability to switch to another fuel. Yet they cannot afford to be complacent. Dual-fuel users do not want to be locked in too tightly, even to a contract with market sensitive pricing, because they will lose the advantage of fuel switching. But the end user who is too reliant on the spot market can suffer as well if there is a price spike or a local supply shortage. Futures and options can help to address these risks and potential opportunity costs by:

Protecting against sharp price spikes caused by occasional pipeline congestion which results in shortages or delivery slowdowns. Assume a large West Coast sawmill and plywood manufacturer relies on natural gas to fire its kilns as it prepares wood for shipment to Eastern Europe under a "just-in-time" delivery contract. A week of unusually cold winter weather causes gas prices to jump because the pipeline cannot move enough gas to meet demand. The plywood company will be heavily penalized, however, for failing to make product delivery if it refuses to meet current natural gas prices. To protect against having to pay a premium for natural gas, the company could have bought a strip of natural gas futures which would have locked in its price over a period of months, no matter what problems the pipeline company may have encountered.

Protecting against falling electricity prices: Assume a paper manufacturer, which has cogeneration facilities and a contract to supply some of the local utility's electricity needs, has contracted with a marketer to purchase a six-month supply of natural gas at an attractive price. Two months into the contract, however, the company becomes concerned that a cool summer will mean declining electricity prices. The company, which has a fixed gas cost, is thus exposed on the electricity market. But the company could potentially offset some of this power generation cost by establishing an intermarket spread — long natural gas futures/short electricity futures or options — for the remaining four months of the contract.

■ Fixing short-term fuel costs: End users may sometimes look for extra protection against seasonal price spikes or may want to lock in their near-term fuel costs for some other reason. For example, assume that a machinery manufacturer receives a large order and must complete production within three months. The company would like to protect its profit margins on the sale by locking in as many of the variable production costs as possible, including fuel costs. The manufacturer could buy futures contracts for those months. Alternatively, the manufacturer could buy call options in order to benefit from increased margins if spot prices decline.

■ Locking in an attractive spot price: The end-user who finds the current natural gas spot price attractive can use the futures market to lock in that price for at least 36 months. Or the end-user can purchase call options to set a ceiling purchase price for gas. These are the same strategies that end-users can use to lock in prices for a short period of time, as discussed above.

■ Hedging storage gas: End-users who have put gas into storage can hedge against falling prices by selling futures, buying puts, or even selling calls against their stored gas.

The Market Needs One More Participant: The Investor

Natural gas market participants may compete with one another, or sit on opposite sides of the negotiating table, but they are all commercial hedgers and they share many of the same risks. A broad spectrum of commercial participation helps ensure that all available supply and demand information is incorporated into the futures price, making it the most efficient indicator of the commodity's value. In addition, broad commercial participation helps ensure that price risk can be laid off on either the long or short side of the market. But experience has shown that if a futures market is to be sufficiently liquid and efficient to provide hedging opportunities, another type of participant is necessary: the investor.

Investors trade with risk capital. They have no position in the underlying commodity and no desire for one, so they have no vested interest in whether the price moves up or down. What they are concerned about is price movement per se; investors seek to profit by correctly anticipating price changes. The more often prices move significantly, the greater the number of potential profit opportunities for the investor.

Active investor participation ensures that commercials can lay off risk as required. Floor traders called locals, who trade for their own account seeking to profit on minor price movements, and investors, who seek to profit by speculating on price direction, keep bid/ask spreads narrow and allow large trades to be made without price disruption. The resulting liquidity leads to increased commercial participation, which generates still greater liquidity.

The natural gas futures market provides investors with many attractive opportunities. Demand for gas is highly seasonal, but the seasonal impact on pricing is unpredictable. Variables include the severity of the winter weather, inventory levels, producers' needs to generate cash to cover their expenses, unexpected changes in demand for gas-generated electricity, transportation prices and constraints, and the cost of natural gas versus the cost of other fuels. The last variable in particular can provide investors with numerous trading opportunities in the form of intermarket spreads, such as the natural gas/heating oil, natural gas/crude oil, and natural gas/propane spreads.

Role of the Exchange

The role of the Exchange in all of this is to provide a trading forum and the financial, technological, and self-regulatory infrastructure that enables participants in the energy and precious metals futures and options markets to conduct business. The Exchange as an institution does not trade these commodities, nor does it set the prices.

Exchange members, acting on their own behalf, on behalf of the companies they represent, or on behalf of their customers, execute the trades by open outcry auction on the trading floor, buying and selling futures and options face-to-face in a trading ring, or by electronic trading after the close of regular floor business. Trading on NYMEX ACCESS℠, the Exchange's after-hours electronic trading system, is conducted on Monday through Thursday evenings in natural gas, electricity, and propane, and overnight on Sundays through Thursdays in crude oil, heating oil, unleaded gasoline, platinum, palladium, gold, silver, and copper.

Trading on NYMEX ACCESS℠

After the close of the open outcry market, the next day's trading session for natural gas futures and options begins with the start of NYMEX ACCESS℠ and runs from 4 P.M. to 7 P.M. Propane gas trades from 5 P.M. to 7 P.M., and electricity trades from 4:15 P.M. to 7:15 P.M. Trader workstations are available throughout the United States; in London; Sydney, Australia; and Hong Kong.

Clearing Futures Trades

At the end of each business day, every futures trade that has been executed is recorded on the books of the Exchange's clearinghouse. The clearinghouse performs several important functions, including assuring that all accounts of clearing members are balanced at the end of each trading day, settling all gains and losses resulting from trading, and acting as the opposite party to every completed transaction, thus severing the original buyer and seller from any further direct obligation to each other. This protection against counterparty credit risk is an important advantage of trading on the New York Mercantile Exchange. Once a trade is executed, the Exchange guarantees its performance. The Exchange becomes, in effect, the seller to every buyer and the buyer to every seller.

The value of this guarantee depends on the financial integrity of the Exchange and its clearing system. The Exchange has taken strong measures to protect this integrity, including: daily price limits; margin requirements; position limits; continuous and rigorous market, trade, and financial surveillance; and capitalization requirements for all clearing members. Each clearing member is required to deposit funds with the clearinghouse on a daily basis in proportion to the number of contracts cleared. These deposits, along with the guarantee funds and surplus reserves of the Exchange, are available against default by any clearing member.

Exchange of Futures for Physicals

One of the most exciting fundamental developments in the natural gas market since the advent of futures trading in 1990 is the growth of a trading and hedging instrument known as an Exchange of Futures for, or in connection with, physical product — called EFPs for short.

An EFP involves the simultaneous execution of both a futures and a physical market transaction, allowing the exchange of a futures position for a physical position in the underlying market. EFP transactions are not unique to energy futures trading; they existed in the grain markets prior to 1920. Although futures contracts are seldom held until delivery, whenever the purchaser of a natural gas futures contract actually does take delivery, it is most likely to be through an EFP.

The EFP alternative has a number of advantages. It allows a company to choose its own partner and its own physical delivery location rather than conform to the delivery location of the Exchange's standard futures contract.

The party holding a long futures position (physical market short) conducts an EFP with a futures market short (physical market long). Both the long and short hedges are liquidated, and physical natural gas is transferred. The long and short hedgers have "swapped" futures obligations, terminating their contract obligations in the futures market. Because the EFP is a non-competitive trade, its price is not made public, and is not included in the calculation of settlement prices.

The EFP alternative allows a trader to liquidate his futures position through an Exchange-approved transaction during trading hours, or based on the settlement price after the market closes, or any other mutually agreeable price. Further, the EFP alternative allows traders to create flexible pricing contracts which would otherwise be difficult to structure and execute.

Futures Basics

Prior to the launch of the Exchange's first natural gas futures contract on April 3, 1990, participants in the natural gas industry had limited means available to manage the relatively new risk of price uncertainty created by deregulation. Ultimate buyers and sellers of natural gas could try to enter into fixed-price transactions. Marketers could attempt only back-to-back transactions. Risk management depended heavily on a company's ability to find a counterparty, or in the case of a marketers, two counterparties, with equal and opposite needs.

The natural gas futures contract greatly expanded risk management opportunities. By bringing together diverse market participants in a central forum, natural gas futures readily allow natural gas buyers and sellers to hedge their price exposure by transferring the risk to investors or to other commercials with inverse risk profiles. Moreover, the natural gas futures market provides an efficient means to discover the market value of natural gas, not just for the next delivery month, but for 36 months into the future.

The success of the natural gas futures contract in meeting the industry's price discovery and risk management needs is clearly demonstrated by the growth of trading activity and open interest in the contract. Open interest defines contracts for which there is no offsetting sale or purchase, or for which actual delivery has not yet taken place. As of March 30, 1998, open interest stood at more than 221,000 contracts, held by more than 100 companies representing the full spectrum of the natural gas industry. Average daily trading volume in 1997 was more than 47,000 contracts, the equivalent of almost 20 times U.S. gas consumption.

What is a Futures Contract?

A commodity futures contract is legally binding. The buyer and seller agree to make or take a cash payment for a physical commodity at an agreed price with the actual delivery and payment to take place at a set date in the future. However, a futures contract has additional features that make it unique — and extremely useful to buyers and sellers of the underlying commodity.

Futures are standardized, fungible, and traded in a centralized marketplace at publicly disseminated prices. They enable the trader to buy or sell (go long or short), and can be traded anonymously.

The quantity of the commodity covered by a futures contract, the delivery period, the specifications and location for delivery, and the timing and method of payment are all standardized. For example, assume a marketer has agreed to sell gas in May to a manufacturing company for $1.81. He does not yet own the gas, so to protect against the risk of a price increase, he purchases one natural gas May futures contract at a price of $1.80 per million British thermal units (MMBtu).

In purchasing the futures contract, he has entered into a contractual agreement to buy 10,000 MMBtu of gas (the standardized quantity) at the Sabine Pipe Line Co.'s Henry Hub in Louisiana (the standardized place of delivery) during the month of May (the standardized delivery period) at a price of $1.80 per MMBtu. The price, of course, is not standardized. It reflects the value of that commodity at that time. Futures prices change continually. The price of a futures contract at any given moment reflects the price that a buyer and a seller have most recently agreed upon, and it may change again in minutes (or seconds) when another buyer and seller agree to a contract at a higher or lower price.

Market participants do not always find these standardized terms ideally suited to their specific needs. However, without standardization, futures markets as we know them could not exist.

Market participants can get out of their positions easily. Take the marketer who has purchased one May contract at $1.80/MMBtu. Two weeks later, he buys gas from a producer to cover his cash market obligation and therefore needs to terminate his futures obligation. He is able to do so simply by selling one May natural gas contract. In other words, he does not have to locate the party on the other side of the trade or search for another counterparty. Instead, he reenters the futures market and sells an offsetting contract with the same delivery month as the one he previously purchased. The sale liquidates the earlier purchase and leaves him 'flat.' In other words, his position is closed and his obligation is terminated.

The ability to establish a position easily and to close it out with equal ease without significantly changing the market price is referred to as liquidity, and it is one of the most important features of a futures market. This degree of liquidity is possible because a futures market is centralized and standardized. All potential buyers and sellers are represented in one location, and all agree to the same contract terms, with price the only variable.

The Exchange clearinghouse plays an important role in maintaining market integrity. The clearinghouse is interposed between the two sides of every trade. It assumes the counterparty credit risk, and guarantees fulfillment of the contract.

Futures contracts are primarily financial management tools; most futures market participants ultimately make offsetting transactions to close out their positions, rather than taking or making delivery of the commodity. In fact, less than 1% of the total Exchange contract volume results in actual physical delivery. Nevertheless, a viable delivery mechanism is needed because it ensures that futures market prices will converge with cash market prices at the termination of trading.

If the marketer wants to close out his May delivery position by making an offsetting transaction, he will have to do so no later than the designated last trading day for that contract. After that day has passed, traders with open positions must fulfill their obligations to make or take delivery. However, position holders who want to make an Exchange of Futures for Physicals, or EFP, have two hours following the close of trading to submit notice to the Exchange.

When the marketer liquidates his position, he will most likely do so at a price other than that at which he entered. The price of a futures contract is subject to a variety of forces, but the most important ones are changes in the supply/demand balance of the underlying commodity and changes in expectations for the future price performance of the underlying commodity.

Assume spot and futures prices have advanced in the two weeks since the marketer bought the May contract at $1.80/MMBtu, with both now trading at $1.90. If the marketer sells the contract at $1.90/MMBtu, he will have a profit of $.10/MMBtu ($1,000), excluding brokerage commissions, in his futures account. If prices declined rather than advanced, however, the marketer would show a loss in his futures account. Assume the price of the May contract has dropped to $1.70/MMBtu. If he sells at $1.70, the marketer will terminate his obligations but he will have a loss of $.10/MMBtu, plus brokerage commissions on the futures trade.

The futures gain or loss represents only half the picture, however. The marketer in this example was using the futures market to lock in a purchase price for gas that he had committed to sell at a fixed price of $1.81. If, in the case where prices rose, he later purchased spot gas at $1.89, he would have a loss of 8¢ on the cash transaction. When this is offset against the 10¢ gain on the futures transaction, the marketer is left with a 2¢ margin. Similarly, if the marketer was able to purchase gas at $1.69 because spot and futures prices declined, he would show a 12¢ gain on the cash transaction. When the 10¢ loss on the futures transaction is offset against the cash market gain, the marketer again has a 2¢ margin.

The marketer in this example initially bought the contract because he needed to protect his margin against the risk of prices going up. To close the position, he made an offsetting sale.

If the marketer had initially agreed to buy gas at a fixed price, he could have sold rather than have bought futures.

It is just as easy to sell, or "go short," a futures contract as it is to buy or "go long." Market participants who fear, or hope for, a price decline can take steps in advance to protect against, or profit from, the results.

In the original example, had the marketer agreed to purchase gas at $1.79, his initial futures trade could have been to sell one May natural gas futures contract at $1.80/MMBtu. In this case, he would incur the obligation to sell the gas at $1.80 in May, rather than to buy it. If the price subsequently went down to $1.70, he would have a gain of $.10/MMBtu ($1,000), less brokerage commissions; if the price went up to $1.90, he would have a loss of $.10/MMBtu ($1,000), plus brokerage commissions. Again, the marketer would expect that this gain or loss would be offset by a loss or gain on the cash transaction, leaving him with an overall profit-margin of 2¢ (if he was able to sell that gas for 1¢ more than the prevailing futures price). Once the marketer completed his cash transaction, he would close out his futures position by making an offsetting purchase of one May contract.

Futures Spreads

Spread positions offer another way of using futures. There are many types of spreads, but they all have two things in common. First, a spread always involves at least two futures positions, which are maintained simultaneously. For example, a trader may be long (have an obligation to buy) 10 June natural gas contracts and short (have an obligation to sell) 10 September natural gas contracts. Second, the price changes in the two or more legs of the position are expected to have a reasonably predictable relationship, and the potential profitability of the spread lies in that relationship or expected changes to that relationship. For example, the trader who is long 10 June contracts and short 10 September contracts will benefit if market forces cause the near-term contract to make a larger advance than the more distant contract — or if market forces cause the distant contract to drop more sharply than the near-term contract.

A spread such as the one described above is called an intramarket spread because all the futures positions involved are based on the same commodity — in this case, natural gas. When two different commodities display a price relationship, like natural gas and propane, it is possible to establish intermarket spreads as well. The "frac spreads" — long natural gas futures/short propane — mentioned earlier are often used by natural gas processors to hedge their margin.

Basis

Successful hedging depends on a close relationship between the price of a futures contract and the price of the underlying physical commodity. This relationship is termed the basis. The closer the basis, the better the hedge.

In the hedge examples presented previously, cash and futures prices moved together perfectly. Hedging 10,000 MMBtus with one natural gas futures contract (representing 10,000 MMBtus) was assumed to result in futures market gains that exactly offset cash market losses, in other words, a perfect hedge with zero basis risk.

Since perfect basis relationships do not actually exist, potential basis fluctuations present the hedger with new opportunities and risks. Hedgers accept the risk of a changing basis because of the fundamental principle of hedging: the price risk laid off is greater than the basis risk taken on.

Basis risk results from the possibility of deviations in three types of relationships: product basis, cash/futures basis, and location basis.

Fortunately, a hedger in the natural gas industry can essentially exclude consideration of product basis. While there are a wide variety of crude oil streams traded, gasoline differs by octane, and even seemingly fungible heating oil can differ depending on its end-use market and sulfur content, pipeline quality natural gas is still pipeline quality natural gas — an almost perfectly fungible commodity. Btus per cubic foot may differ, but there is no real distinction in demand between lower and higher Btu gas. The cash/futures basis and the location basis must, however, be considered.

The cash/futures basis refers to the relationship between the futures price and the spot price of the underlying commodity. Arbitrage — the process of buying physical gas and selling futures, or vice versa — ensures that the two prices will converge by the termination of trading of the futures contract. (It is important to note that if the futures settlement price is compared to a published index, differences in timing between futures settlement and the period used to determine the index may result in differences between those prices. This does not mean that convergence has not occurred.)

For gas bought or sold at a location other than at the futures contract delivery site, the hedger must also consider his location basis. This is the relationship between the futures price and the spot gas price at a location away from the delivery site. On average, the difference between gas prices in two locations should be the cost of transportation between them. But if gas cannot move between two points, or until it does move, relative prices will also be affected by the supply/demand balance in each region.

The relationships between prices at the Henry Hub delivery site and those in most other regions of the country are quite good, and have strengthened over time as improved access to transportation increasingly allows gas to flow to its highest value market. Consequently, gas market participants throughout North America are able to use the futures market to manage their price risk.

Strip Trading in Natural Gas Futures

Energy risk managers who wish to hedge extended exposure to natural gas price risk do not have to buy or sell consecutive futures contracts in multiple transactions to do so. Instead, they can hedge through a single transaction called "strip trading."

Strip trading gives market participants considerable versatility. Price levels can be protected for several months at a time by simultaneously opening a futures position on the same side of the market in each of the months to be hedged. Exchange-traded natural gas strips are available for between two and 36 consecutive months, and the monthly positions are opened as a single transaction at a single price during open outcry trading hours. The strip is valued at an average differential to the previous day's settlement prices for the desired time span. A six-month strip, for example, consists of an equal number of futures contracts for each of six consecutive months, priced as a negotiated differential to the previous day's settlement prices. The differential is the same for each month in the strip and is calculated based on the current average value of those months versus the previous day's settlement.

For example, a trade involving 10 contracts for each of the October through March contract months might be executed at $.10 per million British thermal units (MMBtus) above the previous day's settlement price. In that case, the buyer would receive monthly consecutive long natural gas futures contracts at $.10 above the previous day's settlement price, while the seller would receive short positions in each of those months at the same average differential to the previous day's settlement. For example:

This October-through-March strip settled at an average price of $3.324 per MMBtu. The market is currently trading at an average of $3.424. The liquidation of any month or months of the strip can be accomplished by buying or selling the appropriate futures contract either individually or as all or part of the strip. Of course, buyers or sellers can also choose to go to delivery for any or all of the contracts involved in the strip.

Month	**Previous Settlement Price**	**Today's Trade Price**
Oct	$3.185	$3.285
Nov	$3.220	$3.320
Dec	$3.342	$3.442
Jan	$3.440	$3.540
Feb	$3.405	$3.505
Mar	$3.350	$3.450

Options Basics

As we have seen, a simple long or short futures hedge works much like a fixed price transaction: it locks in a price level. The hedger thus obtains full protection against adverse price moves but incurs an opportunity cost if prices move favorably. At times, the hedger is more than willing to accept this trade-off. At other times, he is not.

There is another risk management tool — an options contract — which allows a hedger to achieve price protection while retaining the ability to participate in favorable price moves. His opportunity cost is limited to the premium paid for the option.

But that is just one of the main risk management and trading opportunities afforded by this highly flexible tool. The natural gas options contract which opened for trading October 2, 1992, complements the futures contract by allowing a company to develop a host of trading strategies, using either contract alone or in combination, to fit virtually any risk profile, time horizon, or cost consideration.

What is an Options Contract?

An options contract essentially works like an insurance policy. If a homeowner wants to protect himself against a risk, he pays an up-front premium. If the risk occurs, he is reimbursed. If the risk doesn't occur, he is out nothing but his premium.

When the homeowner buys an insurance policy, he doesn't assume any obligations. He pays his premium and receives the right to reimbursement if the specific risk occurs. The insurance company that writes the policy takes on an obligation, though. In exchange for the premium, the company is obligated to reimburse the homeowner if the risk occurs and he files a claim.

The holder of an options contract has the right, but not the obligation, to exercise his option. The seller, or writer, of an options contract has an obligation to perform if called upon to do so.

There are two types of options: calls and puts. A call gives the holder of the options contract the right, but not the obligation, to buy the underlying futures contract. Conversely, a put option gives the holder the right but not the obligation to sell the underlying futures contract.

The price at which the underlying futures contract may be bought or sold is the exercise price, also called the strike price.

An options contract affords the right to buy or sell for only a limited period of time; each options contract has an expiration date.

On the opposite side, a seller, or writer of an options contract incurs an obligation to perform, should the option be exercised by the purchaser. Therefore, the writer of a call incurs an obligation to sell a futures contract and the writer of a put has an obligation to buy a futures contract.

Because trading on the Exchange is done with anonymous counterparties, when an option is exercised, the Exchange randomly assigns an options writer to fulfill the obligation.

Options Rights and Obligations

Call		***Put***	
Buyer	Has the right to buy a futures contract at a predetermined price on or before a defined date. ***Expectation:*** Rising prices	**Buyer**	Has right to sell futures contract at a predetermined price on or before a defined date. ***Expectation:*** Falling prices
Seller	Grants right to buyer, so has obligation to sell futures at predetermined price at buyer's sole option. ***Expectation:*** Neutral or falling prices	**Seller**	Grants right to buyer, so has obligation to buy futures at a predetermined price at buyer's sole option. ***Expectation:*** Neutral or rising prices

Terminating An Options Position

An option is a wasting asset. It has an initial value that declines, or wastes away, as time passes. Depending upon the movement of an options price, the buyer will choose one of three alternatives for terminating an options position: He can exercise the options contract, liquidate it by selling it back on the Exchange, or let it expire. While liquidation is the most common choice, a small percentage of buyers choose to exercise, particularly if their strategy calls for acquiring a long or short futures position at the strike price. The ability to trade in and out of positions is the great advantage of standardized options contracts.

If the futures price does not move far enough for an exercise or an offsetting position to be worthwhile, or moves in the opposite direction, buyers can simply let their options contract expire worthless.

The Pricing of Options

In return for rights without obligations, options buyers pay options sellers a premium. The four major factors affecting the premium, or price, are:

- Futures price relative to options strike price
- Time remaining before options expiration
- Volatility of underlying futures price
- Interest rates

As in the futures market, options trading takes place both in an open outcry auction market on the floor of the Exchange and electronically via NYMEX ACCESS℠. While the value of futures is tied to the underlying cash commodity through the delivery process, the value of an options contract is related to the underlying futures contract through the ability to exercise the option.

Strike Price vs. Futures Price

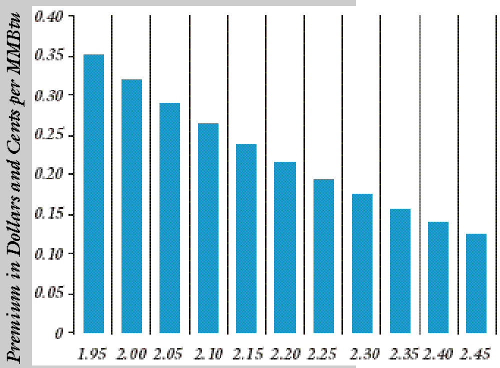
The most important influence on an options price is the relationship between the underlying futures price and the options strike price.

Depending upon futures prices relative to a given strike price, an option is said to be at-the-money, in-the-money, or out-of-the-money. An option is at-the-money when the strike price equals or is closest to the price of the underlying futures contract.

An option is considered in-the-money when the price of the futures contract is above a call's strike price, or when the futures price is below a put's strike price.

A call is out-of-the-money when the futures price is less than the options strike price (Figure 1). For example, if the December natural gas

Impact of Futures – Strike Relationship on Call Options Premium



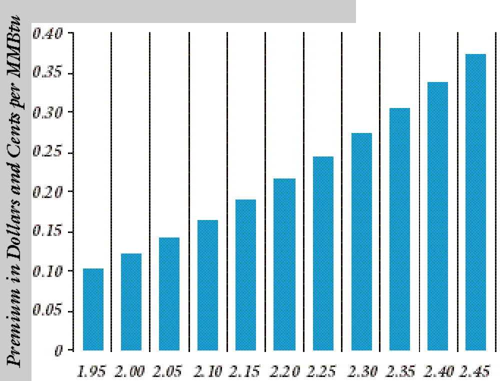
Desired Call Options Strike Price

Futures = $2.20; Strike = $2.20; Interest = 5%

Days = 90; Volatililty = 30% above and 50% below

Figure 1

Impact of Futures – Strike Relationship on Put Options Premium



Desired Put Options Strike Price

Futures = $2.20; Strike = $2.20; Interest = 5%

Days = 90; Volatililty = 30% above and 50% below

Figure 2

futures price is $2.50 per million British thermal units and the December $2.65 call grants the holder of the options contract the right to buy a December futures contract at $2.65, it is clearly-out-of-the-money.

Conversely, a put is out-of-the-money when the underlying futures price is higher than the put's strike price (Figure 2).

An options premium will usually equal or exceed whatever intrinsic value the options contract has, if any. Intrinsic value is the amount by which options are in-the-money. It is never a negative number.

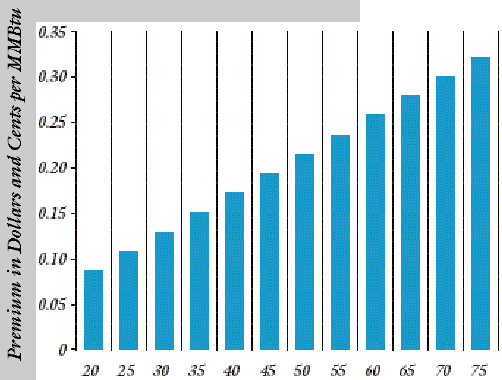
Natural gas strike prices are listed in increments of 5¢ per million British thermal units (MMBtu). In the first three months of a contract, there are 60 strike prices in five-cent increments, with 40 strike prices above and 20 below the at-the-money strike price, which is the price nearest to the previous day's close of natural gas futures and 10 strike prices in increments of $.25 (25¢) per MMBtu above the highest and below the lowest existing strike price for a total of at least 81 strike prices. In the fourth month and beyond of a contract, there are 40 strike prices in five-cent increments, 20 above the at-the-money price and 20 below and an additional 10 strike prices listed in 25¢ increments above the highest $.05 and below the lowest $.05 surrounding the at-the-money price for a total of at least 61 strike prices. Strike price boundaries are adjusted according to the futures price movements.

Volatility

Volatility is an important factor in the pricing of options. As prices fluctuate more widely and frequently, the premiums for options on futures increase, since the probability of options attaining intrinsic value or moving deeper into the money increases. Accordingly, writers demand higher premium payments. However, if market volatility declines, premiums for puts and calls decline correspondingly.

Assume that natural gas futures prices are at $2.25 and, during the past year, have ranged between $2.10 and $2.40. Unless there is good reason to expect that the futures contract will break out of its past trading range, a $2.50 call would be expected to be relatively inexpensive. But if prices have ranged between $1.75 and $2.75 over the past year, that same call would be expected to cost more.

Impact of Volatility on Options Premium



Days to Options Expiration

Futures = $2.20; Strike = $2.20; Interest = 5%

Days = 90; Volatililty = 30% above and 50% below

Figure 3

An options seller will want more money because the probability that the $2.50 call will move into the money is higher. An options buyer will be willing to pay more since, if prices have been trading in a wider range, his price risk is most likely higher.

Historical volatility is calculated from the past movement of natural gas prices over a specified time period. Technically, historical volatility is the standard deviation of the log of the changes in the futures price, expressed in percentage terms, annualized. Or, to put it another way, 50% volatility, for example, means that there is a 68.3% chance (one standard deviation) that a year from now, prices will be 50% higher or lower.

Historical volatility is useful because it provides a basis for forecasting future volatility, which is what options traders really want to know.

Implied volatility is also important to options traders. Implied volatility is embedded in the price of an option and represents the market's forecast of future volatility. Since the past is not necessarily a good forecaster of the future, at any point in time, implied volatility may be higher or lower than historical volatility.

Volatility has a large impact on an option's price, as shown in the following chart (Figure 3). The premium for a $2.20 strike at-the-money options contract with 75 days to expiration is 21¢ at 50% volatility, and drops to only 11¢ at 25% volatility.

Natural Gas 20-Day Historical Volatility

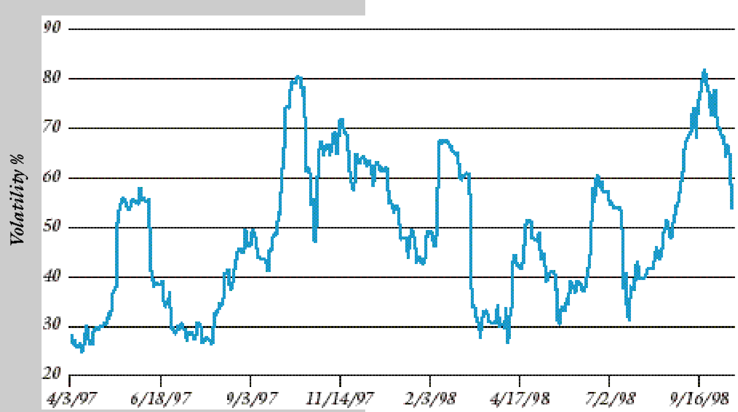
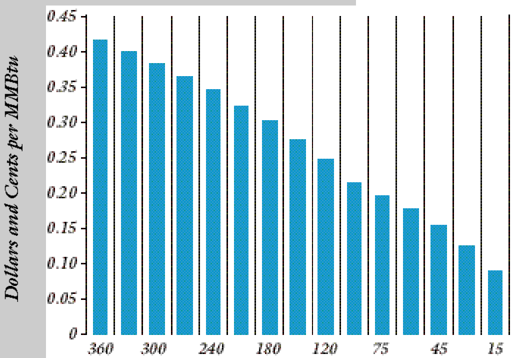


Figure 4

Volatility is the key component to options pricing. It is, in fact, the only unknown in the options pricing model. Given an options market price and knowing the other variables in the pricing model — the futures price, the strike price, the time to expiration and interest rate — the remaining factor — the derived volatility — is implied by the option's price. When the implied volatility appears low compared to history and, more importantly, to a forecast of future volatility, options traders will tend to buy options. Conversely, when implied volatility appears high, traders will tend to sell options.

The 35% volatility assumption used in the hedge example in this brochure may, on any given day of options trading, be too high, too low, or just right when compared with actual implied volatility. Thirty-five percent was cho-

Impact of Time on Expiration Options Premium



Futures = $2.20; Strike = $2.20; Interest = 5%
Days = 90; Volatililty = 30% above and below 50%

Figure 5

sen simply as an example, but as shown in the historical volatility chart, is certainly not outside the realm of possibility (Figure 4).

Time Value

Another component of an option's premium is its time value. The time premium is the amount buyers are willing to pay for the options above their intrinsic value on the chance that, at some time prior to expiration, they will move into the money. Premiums on out-of-the-money options are fully based on time since their intrinsic value is zero, as are at-the-money options. As options become deeply in- or out-of-the-money, the time premium shrinks substantially.

The time premium for in-the-money options is the amount that exceeds the options' intrinsic value and reflects the possibility that the options may move deeper into-the-money. The time value of an option necessarily shrinks as the expiration date approaches. The reason is that there is less and less time for a major change in market behavior, and a decreasing likelihood that the options will increase in value (Figure 5).

Interest Rates

Interest rates have a bearing on options prices because they represent the profit or cost that could result from an alternate use of the funds used for the premium. Interest rates of 90-day U.S. Treasury bills are often used as a guide. In practice, though, isolating the effect of interest rates on options premiums is difficult, if not impossible. A change in interest rates influences the net present value calculation of a premium, the cost of buying and storing a commodity, and even the commodity's price. Most of the interest rate effect will already be incorporated in the futures price through the cost of carrying the physical commodity.

Options Value at Expiration

Options prices are linked to futures prices through the exercise feature. If, at the call option's expiration, futures are trading at $2.70, a $2.20 call, if exercised, is worth 50¢, the difference between the futures price and the strike price. The reason is that the holder of a $2.20 call can exercise his option, receive a long futures position at $2.20, immediately turn around and sell the futures contract for $2.70, and make 50¢. If the trader notices that the market value of a $2.20 call has declined to 30¢, he may still wish to purchase additional $2.20 calls. Adding the 30¢ to the $2.20 call brings the intrinsic value of the trader's position up to $2.50. When he exercises his option and obtains a futures contract, he is then able to sell that futures contract for the prevailing $2.70 and realize a risk-free 20¢ profit — the difference between the futures price and his options investment (exclusive of transaction costs); market forces ensure that an opportunity like this cannot last long.

Options cannot have a negative value, so if the risk does not occur, that is, if futures prices do not exceed the strike price, the options will be worth zero. No one will exercise the right to buy futures at $2.20 via options when they can buy the futures directly in the futures market at $1.70.

For a put option, the risk is the possibility that the futures price will be below the strike price. When this occurs, the options will be worth precisely the difference between the strike price and the futures price. Since a put gives its holder the right to sell futures, if futures are at $1.70, the holder of a $2.20 put could exercise the put into a short futures position at $2.20 and immediately buy it back for $1.70, making 50¢ (exclusive of transaction costs). At expiration, the put will be worth 50¢.

If the risk does not occur, that is if futures prices are not below the strike price, the options will be worth zero. No one would exercise the right to sell futures at $2.20 when they can sell them in the futures market for $2.70.

Hedge Examples

Long Hedges

Gas buyers wishing to protect against future increases in spot gas prices have a number of alternatives open to them. Purchasing futures allows them to lock in a price level. Buying call options allows them to obtain protection against price increases while still participating in price declines. Examples of these strategies follow. Other strategies not described in this brochure also exist: for example, selling call options or employing a fence (buying calls and selling puts). Additionally, gas buyers who have entered into a fixed price purchase contract can use put options to participate in a price decline should their market view change after they have entered into the purchase arrangement.

Hedging Against a Natural Gas Price Increase by Buying Futures

Assume that on September 23, a gas buyer such as a manufacturer, an LDC, or a marketer who has committed to a fixed-price sale of gas becomes concerned about the impact of a cold winter on natural gas prices. He purchases January natural gas futures which are trading at $2.20.

On December 21, the gas buyer purchases the gas he needs in the spot market. Since he no longer has exposure in the cash market, he also closes out his January futures contracts. The chart below illustrates the results if the price of gas has increased to $2.70 (Case A) or declined to $1.70 (Case B).

	Case A **Prices Increase**	**Case B** **Prices Decrease**
December 21: Spot Price	$2.70	$1.70
December 21: Futures Price	$2.70	$1.70
Gain or Loss on Futures		
Sales Price	$2.70	$1.70
Purchase Price	$2.20	$2.20
Minus Profit from Sale of Futures	$0.50	($0.50)
Cash Market Cost of Gas	$2.70	$1.70
Effective Cost of Gas	$2.20	$2.20

Summary of results: In Case A, the gas buyer pays $2.70 to his supplier for gas, but the financial offset provided by the 50¢ futures profit gives him an effective gas cost of $2.20.

In Case B, the gas buyer would have had a lower gas acquisition cost had he not hedged. Obviously, if he had known that prices were going to decline, he would not have hedged. But, of course, he was unsure of price direction and was willing to accept a price of $2.20, even if spot prices ended up being lower, to ensure that he would not have to pay more than $2.20 for his gas.

Buy Call Strategy Options Profit/Loss at Expiration

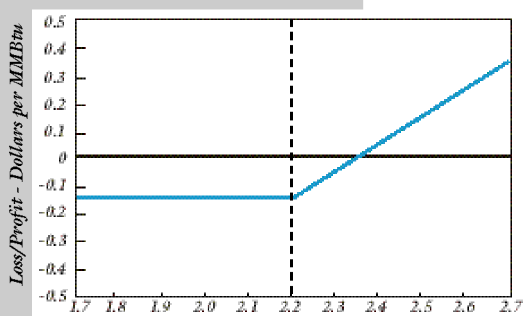


Figure 6

Hedging Against a Natural Gas Price Increase by Buying Calls

Assume that on September 23, another gas buyer becomes concerned about a possible increase in winter natural gas prices. January natural gas futures are trading at $2.20. The gas buyer considers purchasing futures contracts, thereby locking in a purchase price of $2.20 for its January gas. However, he does not want to be significantly above the market should spot prices decline, and thus decides to buy a January call options contract with a strike price of $2.20 for 15¢.

On December 21, the gas buyer purchases spot gas, and liquidates his options position. The chart below illustrates the results if the price of gas has increased to $2.70 (Case A) or if it has declined to $1.70 (Case B).

	Case A Prices Increase	**Case B Prices Decrease**
December 21: Spot Price	$2.70	$1.70
December 21: Futures Price	$2.70	$1.70
Gain or Loss on Options		
Sales Price	$0.50	0
Purchase Price of Options	$0.15	$0.15
		($0.15)
Cash Market Cost of Gas:	$2.70	$1.70
Minus Revenue from Options	$0.35	
Effective Cost of Gas	$2.35	$1.85

Net Purchase Price At-the-Money Call Purchase

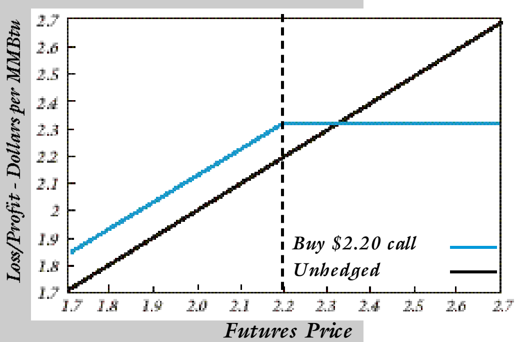


Figure 7

Summary of results: In Case A, the gas buyer pays $2.70 per MMBtu to his supplier for gas, but the financial offset provided by the 35¢ option profit gives him an effective gas cost of $2.35. This is 15¢ more per MMBtu than his effective cost when using futures to hedge, because he paid 15¢ per MMBtu for the option's contract premium.

The reason the gas buyer chose to pay this 15¢ becomes apparent in Case B. The buyer pays his supplier $1.70 per MMBtu. The $2.20 call option — the right to buy futures at $2.20 — is now worthless because futures are trading at $1.70. So there is a net loss of 15¢ per MMBtu — the option premium paid — on the options position, giving him an effective gas cost of $1.85 per MMBtu. This is 35¢ less per MMBtu than if futures alone were used to obtain price protection.

The profit and loss profile of the call options purchase at expiration and the gas buyer's net purchase price are graphed in figures 6 and 7 for a range of futures price outcomes.

Hedging Against a "Catastrophic" Natural Gas Price Increase

Net Purchase Price At- versus Out-of-the-Money Calls

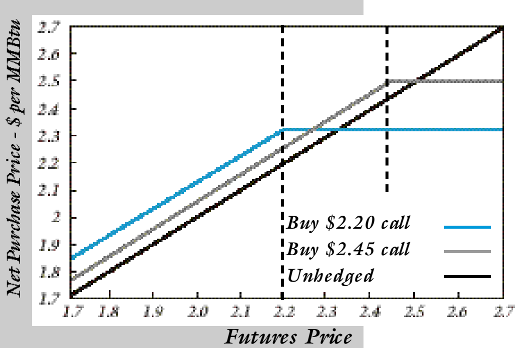


Figure 8

Assume that on September 23, another gas buyer is worried about a possible weather-induced price spike in the winter. However, aside from that eventuality, he believes that supply and demand fundamentals are such that prices are very likely to fall below the $2.20 price at which January futures are trading at the time. So he's not going to buy futures for protection, because he would be prevented from participating in the expected decline. He considers buying a $2.20 January at-the-money call for 15¢, but he knows that if prices do fall, his costs will be higher by that 15¢. After examining his budget, he decides he can afford to pay about $2.50 for January gas. He thus purchases a $2.45 strike call for 7¢.

The gas buyer has, in effect, decided to buy catastrophe insurance. Believing the likelihood of a price increase is small, he is willing to absorb a significant price move to reduce his insurance cost. The financial results of that decision are illustrated in Figure 8.

Summary of results: Had the gas buyer not hedged, his net purchase cost would be somewhere along the full 45-degree line. Had he bought an at-the-money call, his purchase price would be higher by the amount of the premium at prices up to the strike. At a futures price of $2.35 (the strike price plus the premium) he would break even. At higher futures prices, he would be penny-for-penny better off having hedged.

By purchasing the out-of-the-money $2.45 strike call, the gas buyer will still pay more at prices up to $2.52 (the strike plus the 7¢ premium) than if he had not hedged. Compared to hedging with the $2.20 at-the-money call, he is better off at futures prices below $2.28. The break-even point between two alternative strike calls is the lower strike plus the difference in the premiums. In this example, $2.20 + (15¢ - 7¢) = $2.28. So if he believes prices are likely to be below $2.28 but he still wants protection against a dramatic up move, he is likely to choose to purchase the $2.45 strike call.

Short Hedges

Gas sellers wishing to protect against future decreases in spot gas prices also have a number of alternatives open to them. Selling futures allows them to lock in a price level. Buying put options allows them to obtain protection against price decreases while still participating in price declines. Examples of these strategies follow. Other strategies not described in this brochure also exist: for example, selling put options or employing a fence (buying puts and selling calls). Additionally, gas buyers who have entered into a fixed-price purchase contract can use put options to participate in a price decline should their market view change after they have entered into the purchase arrangement.

Hedging Against a Natural Gas Price Decrease by Selling Futures

Assume that on September 23, a gas seller, perhaps a producer or marketer who has committed to a fixed-price purchase of gas, becomes concerned about the impact of a warm winter on natural gas prices. He sells January natural gas futures which are trading at $2.20.

On December 21, the supplier sells his gas in the spot market. Since he no longer has exposure in the cash market that needs to be hedged, he also closes out his January futures contracts. The following chart illustrates the results if the price of gas has decreased to $1.70 (Case A) or if it has increased to $2.70 (Case B).

	Case A Prices Decrease	Case B Prices Increase
December 21: Spot Price	$1.70	$2.70
December 21: Futures Price	$1.70	$1.70
Gain or Loss of Futures		
Sales Price	$2.20	$2.20
Purchase Price	$1.70	$2.70
Cash Market Revenue	$1.70	$2.70
Plus Profit from Sales of Futures	$0.50	($0.50)
Effective Revenue	$2.20	$2.20

Summary of results: In Case A, the supplier received $1.70 for his gas, but the financial offset provided by the 50¢ futures profit gives him an effective gas sales price of $2.20.

In Case B, the supplier would have had a higher gas sales price had he not hedged. Obviously, if he had known that prices were going to increase, he would not have hedged. But, of course, he was unsure of price direction and was willing to accept a price of $2.20, even if the spot price ended up being higher, to ensure that he would never receive less than $2.20 for his gas.

Hedging Against a Natural Gas Price Decline by Buying Put Options

Assume that, on September 23, a gas seller is concerned that warm winter weather will drive gas prices down. Since January futures are trading at $2.20 per MMBtu, the supplier considers selling futures to lock in that price. However, he realizes that if it is very cold instead, prices could rise well above $2.20, and he would like to be able to earn the higher revenue. So he decides to use options instead of selling futures, buying a January put option with a strike price of $2.20 for 15¢.

On December 21, the gas seller makes his sale in the spot market and liquidates his options position. The table on the following page illustrates the results if the price of gas has decreased to $1.70 (Case A) or if it has increased to $2.70 (Case B).

Buy Put Strategy
Options Profit/Loss at Expiration

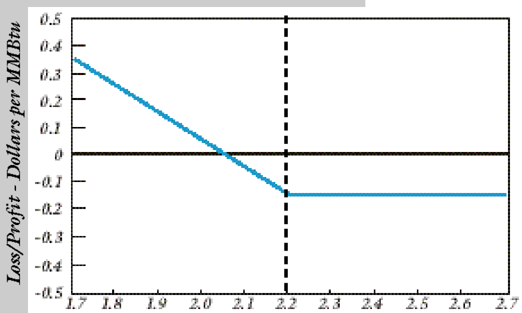


Figure 9

Net Sales Price
At-the-Money Put

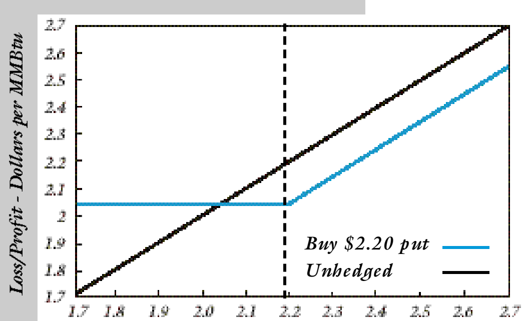


Figure 10

	Case A Prices Decrease	Case B Prices Increase
December 21: Spot Price	$1.70	$2.70
December 21: Futures Price	$1.70	$2.70
Gain or Loss on Options		
Sales Price	$0.50	0
Purchase Price of Options	$0.15	$0.15
Plus Revenue from Options	$0.35	($0.15)
Cash Market Revenue	$1.70	$2.70
Effective Revenue	$2.05	$2.55

Summary of results: In Case A, the supplier receives only $1.70 per MMBtu for his gas, but the financial offset provided by the 35¢ per MMBtu options profit gives him an effective selling price of $2.05. This is 15¢ less per MMBtu than his effective revenue when using futures to hedge, because he paid a 15¢ premium for the options contract.

The reason the supplier chose to pay this 15¢ becomes apparent in Case B. The supplier now receives $2.70 per MMBtu from the spot market sale. The $2.20 put option — the right to sell futures at $2.20 — is now worthless because futures are trading at $2.70. So there is a net loss of 15¢ per MMBtu — the options premium paid — on the options position, giving the gas seller an effective selling price of $2.55 per MMBtu. This is 35¢ more per MMBtu than if futures were used to obtain price protection.

To further illustrate the effect of options, Figure 9 shows the degree of profit or loss on the value of the options contract should the futures price decline and the put option be exercised or sold, as well as the embedded $.15 expense of the options premium on the upside when the option is simply allowed to expire.

Figure 10 compares the net sales price of a futures contract with and without the use of options. As the shaded portion illustrates, the profit margin of an exercised put option becomes increasingly larger as the futures market price declines. On the other hand, the purchaser of a put option is able to gain the full advantage of any price increase with his loss being limited to the $.15 premium paid for the option.

Net Purchase Price At- versus Out-of-the-Money Puts

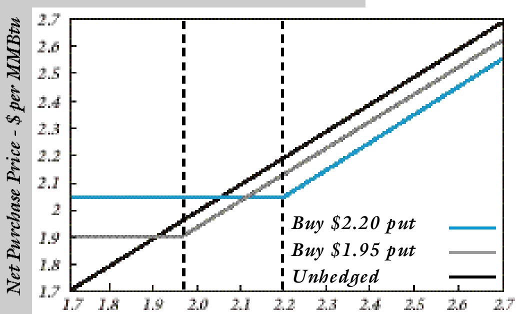


Figure 11

Hedging Against a "Catastrophic" Natural Gas Price Decline

On September 23, a third gas supplier is considering hedging against another warm winter. However, he believes that this is unlikely, and, moreover, that supply and demand fundamentals are such that even a normal winter would result in a sizable price increase. So he doesn't want to hedge with futures, thereby locking in the January futures price of $2.20 per MMBtu, nor does he want to spend 15¢ for an at-the-money put. But knowing he'll have cash flow problems if he has to sell January gas for less than $1.85, he decides to buy a $1.95 put for 5¢.

Figure 11 illustrates the results of this strategy, compared to a decision to not hedge or to hedge with an at-the-money put.

Summary of results: Had the supplier purchased an at-the-money put, he would break even at $2.05 per MMBtu — the $2.20 strike less the 15¢ premium. If futures prices are lower than that, he will be better off having hedged with the $2.20 put.

With the $1.95 put, the producer's break-even vis-à-vis being unhedged drops to $1.90. But his break-even compared to the purchase of the $2.20 put is $2.10. The break-even point between the alternative strike puts is the higher strike price less the difference in the premiums. In this example, $2.20 - ($.15 - $.05) = $2.10 per MMBtu.

At higher futures prices, he will be better off with the out-of-the-money $1.95 put. So if he thinks prices are likely to be above $2.10, but he still wants some downside protection, the $1.95 put is a logical choice.

The ability to select among strike prices is but one example of the enormous flexibility of options as a risk management tool. Once a company determines the level of protection it needs and the amount it is willing to pay for that protection, an options strategy can be devised to suit those requirements.

Exchange Procedures and Safeguards

The Exchange takes specific steps to ensure that traders and trading companies have the capital to meet their obligations and that trading itself is carefully monitored. Among the safeguards the Exchange has established are the enforcement of daily commodity price limits and individual position limits on each participant, specific margin account requirements, and close surveillance of trading activity. These actions are part of the basic mechanics of running a sound and efficient exchange.

Price Limits

Exchanges set limits on the amount by which the price of a futures contract is allowed to fluctuate during one trading day. These limits specify the maximum amount by which the price may move above or below the prior day's settlement price.

Minimum price limits for natural gas futures and options are $.001 per MMBtu. There are no maximum daily price limits on options, while maximum daily price fluctuations for futures are $1.50 per MMBtu in the first two months, applicable in two stages. In all other contract months, the maximum fluctuation is $.15 per MMBtu, which is expandable to $.30 MMBtu if the previous day's settlement price is at the $.15 limit. If prices move up or down half the limit in the first two months, i.e. $.75, there is a trading halt for an hour, and when trading reopens, the limit — not just for the first two months but for all months — is expanded to $.75 per MMBtu from the limit in place in the direction of the move when the market re-opens.

Margin

Margins are good faith deposits that can be used to cover adverse moves in futures prices. The Exchange must assure that participants have sufficient funds to handle losses, and consequently requires its market participants to post and maintain in their accounts a certain minimum amount of funds for each open position held. The Exchange collects margin directly from its clearing members who, in turn, are responsible for the collection of funds from their clients.

The margin process functions according to daily reconciliation with settlement prices, known as "marking-to-market." This procedure ensures that at the end of each day, funds flow from those who have seen the value of their position decrease to those who have realized gains. After the initial customer margin is deposited, customers must also maintain their accounts in the face of adverse price movements. If a customer finds his margin deposit eroded by more than 35%, the customer receives a margin call from his broker informing him that he must post additional (variation) margin in order to restore his account to minimum levels.

The Exchange uses Standard Portfolio Analysis of Risk (SPAN) to establish minimum margin levels for clearing firms and their customers. SPAN, developed by the Chicago Mercantile Exchange, has become the futures industry's standard of margining. SPAN evaluates the risk of a trader's entire portfolio and establishes plausible movements in futures prices over a one-day period. The resulting effect of these "risk arrays" is to capture respective gains or losses on futures and options positions across the energy commodities.

One of the special characteristics of options is that a long options position can never be at risk for more than its premium. For SPAN to assess the risk of all positions in the portfolio and, at the same time, allow credit for the premium involved, SPAN allows the excess of the options premium over the risk margin for any options position to be applied to the risk margin on other positions.

Margins are typically determined by the underlying volatility in the market. Historically, they have tended to range between 5% and 15% of contract value.

Margins are set independently for outright positions and for spread positions. The margin for spread positions is lower than for outrights because the risk associated with those positions is usually lower.

An additional margin assessment is required for any spot month position open on the business day prior to expiration of the futures contract. Positions remaining open that close to expiration are likely to result in delivery; the high margin is intended to help ensure that the customer is financially able to stand for delivery.

Exchange rules concerning original margin payments stipulate that customers must post either cash or U.S. Government obligations with less than one year to maturity. A client must deposit these funds with a futures commission merchant (FCM). The FCM must deposit the funds in a segregated bank depository through a clearing member. The Exchange accepts cash or U.S. Government securities and letters of credit directly from clearing members to fulfill original margin requirements. Variation margin requirements must be met by cash.

Margin requirements and contract specifications are subject to change.

Position Limits

An orderly market is also ensured by placing limits on the number of positions a participant can hold at a given time. Each clearing member has position limits, based on its capitalization. Customers are subject to speculative position limits, which can be expanded by special permission of the Exchange president if the customer shows solid proof that he is a bona fide hedger with physical or derivative market risk that exceeds the position limits.

Surveillance

The Exchange's compliance department is charged with market, trade, and financial surveillance. Market activity is continuously monitored for indications of possible disruption or other market situations conducive to price distortions. The Exchange also enforces a rigorous self-regulatory program by closely monitoring and regulating trading activity to prevent market manipulation and other anti-competitive activity. Financial surveillance ensures that clearing members can meet their margin requirements and that position limits are strictly observed.

Capital Requirements for Clearing Members

Since it is the clearing members, in fact, who are the ultimate guarantors of trade performance, clearing members are closely monitored and are required to demonstrate at least $500,000 in working capital. Position limits are set based on each clearing member's capital. Clearing members must also contribute between $100,000 and $2 million to a Guaranty Fund administered by the Exchange's clearing department. The fund, which currently holds more than $72 million, is available in case a clearing member should fail to meet its requirements. It has never been necessary to draw on it.

Price Dissemination

New York Mercantile Exchange prices and volumes are widely disseminated and readily available. Prices are transmitted instantaneously around the world by real-time electronic quotation vendors. They are also available from newspapers, and *Fastfacts*, the Exchange's 24-hour telephone information service, which updates price and volume data every five minutes. New information is available within 30 minutes of real-time. Call *Fastfacts* at (212) 301-4871 and then enter the following three-digit codes for the information you want on natural gas futures and options:

	Futures	Options
Intra-session update	181	281
Closing prices	182	282
Open interest	184	284
Total volume	188	288
NYMEX ACCESS℠ final price	183	283

In addition, daily highs and lows, estimated volume, and settlement prices for all futures and options traded on the Exchange are also available daily at the Exchange's world wide web address http://www.nymex.com.

For more information about the Exchange and its futures and options contracts, write, call, or fax:

Publications Office
New York Mercantile Exchange
One North End Avenue
New York, NY 10282-1101
Telephone: (212) 299-2777
Fax: (212) 301-4700
E-mail: publications@nymex.com
Worldwide web site: http://www.nymex.com