3. Managing Risk With Derivatives in the Petroleum and Natural Gas Industries

Introduction

For more than 20 years, businesses in the petroleum and natural gas industry have used derivatives to reduce their exposure to volatile prices, limit their need for cash cushions, and finance investment. In recent times, however, derivatives and energy trading generally have been implicated in Enron's bankruptcy, manipulation of the California electricity market, and major downgrades of energy company credit ratings and growth prospects. This makes reasonable people wonder whether derivatives create more risk than they manage.

The preceding chapter described the concept of business risk in general and the importance of managing price risk for energy businesses in particular. This chapter looks at the current state of U.S. spot markets for oil and natural gas and shows that derivatives of various kinds have proven useful in managing price risk, especially for small and medium-sized firms operating in only one or a few market segments.

There is vigorous competition among suppliers of risk management tools for energy firms, and the market for derivative contracts is large. But there are problems. Enron's case illustrates that certain derivatives, especially pre-paid swaps, have been used to disguise what appear to be loans from stockholders. The Securities and Exchange Commission (SEC) and the Congress are vigorously investigating these abuses for the purpose of ending them.

Oil and Natural Gas Markets

Domestic oil and petroleum prices were deregulated in the 1980s, and natural gas prices were partially deregulated. Before price deregulation, the market for domestic oil and gas derivatives was limited. Under price regulation, the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the State public utility commissions (PUCs) directly or indirectly controlled the prices of domestic crude oil, petroleum products, wellhead natural gas, pipeline transmission, and retail gas service.[22] Government was also deeply involved in deciding the merits of pipeline investment and siting. The immediate effect of price controls was to stabilize price. Unfortunately, price certainty was paid for with shortages in some areas and surplus elsewhere and by complex cross-subsidies from areas where prices would have been lower to areas where prices would have been higher, with accompanying efficiency costs.[23]

Currently, the prices of crude oil, natural gas, and all petroleum products are free from Federal regulation. The FERC continues to impose price ceilings on pipeline services and has approval authority for new pipeline construction. Most States continue to regulate prices for small users of natural gas (residences and commercial enterprises), but large users—particularly, power plants, which accounted for about 21 percent of the Nation's natural gas consumption in 2001, and petrochemical plants—are generally free to make their best deals.

Spot markets have long been an important part of international trade in crude oil and petroleum products. For example, oil tankers routinely are diverted en route to take advantage of price differences that arise during transit. In the United States, price deregulation has encouraged the rapid growth of domestic spot markets. According to the New York Mercantile Exchange (NYMEX), " In 1982 a spot market for natural gas hardly existed; by the late 1980s, it accounted for 80% of the entire gas market."[24] Although spot transactions had fallen to between 35 and 40 percent of the overall market by 1992, most of the remainder was bought and sold under long-term contracts at prices that usually were tied to those in the spot markets. A similar process had unfolded earlier in domestic crude oil and petroleum product markets.

Spot markets fundamentally change how businesses perceive their opportunities. The opportunity costs of idle assets become apparent, because spot markets make current price visible. Firms can clearly see how small differences in the timing of their acquisition, production, and storage decisions affect their profits. Firms also have the option of using a liquid spot market as if it were an

[22]The FERC's authority was limited to natural gas that entered interstate commerce.

[23]See J. Kalts, *The Economics and Politics of Oil Price Regulation* (Cambridge, MA: MIT Press, 1981); and P.W. MacAvoy and R.S. Pindyck, *Price Controls and the Natural Gas Shortage* (American Enterprise Institute, 1975, and University of Arizona Press, 1977).

[24]NYMEX, *Risk Management with Natural Gas Futures and Options* (June 4, 2001), p. 3.

actual supplier, warehouse, or customer. Customers can easily compare the price of a supplier's offer with the spot market price. In addition, spot markets are critical for the valuation of cash-settled derivative contracts.[25]

The advent of energy spot markets has also introduced some new risks. For example, sometimes commodities cannot be sold in the spot market or, if they can, only at prices substantially different from the last reported market price.[26] Sometimes spot market prices appear to be manipulated.[27] If the reported spot prices are not accurate, or if the market is subject to manipulation or turmoil, traders may be unable to design, much less trade, derivatives. The best defense against these problems is large, liquid spot markets with many buyers and sellers.

Crude Oil and Petroleum Products

Much of the nearly 79 million barrels per day of crude oil produced worldwide in 2000 was sold into international markets. World oil traders use several locations and types of crude oil as pricing benchmarks. The price of West Texas Intermediate (WTI), a light, sweet (low-sulfur) crude oil sold at Cushing, Oklahoma, is used as a principal pricing benchmark for spot trading in the United States. Brent crude, a light, sweet North Sea oil, serves as an international pricing benchmark.[28] Brent is shipped from Sullom Voe in the Shetland Islands, United Kingdom, and is traded actively on a free-on-board (FOB) basis. There are many other types of crude oil, and their pricing is frequently expressed as a differential to Brent or WTI, depending on quality differences and location. Crude oil and petroleum product prices vary with world economic growth, weather and seasonal patterns, and regional refining and transportation capability. Crude oil prices have also been sensitive to international political events and to the production policies of the Organization of Petroleum Exporting Countries (OPEC).

Tankers move most crude oil from producing areas to major markets in the United States, Northwest Europe, and Japan for refining. The three major trading areas for refined products are New York Harbor, Northwest Europe (Antwerp, Amsterdam, and Rotterdam), and Singapore. There are also dozens of other trading areas for refined products, including Japan and the U.S. Gulf Coast, West Coast, and Midwest. The physical trading of refined products tends to be regional, with surpluses also being traded internationally.

Although more than 50 percent of the petroleum consumed in the United States originates from foreign sources, domestic crude oil production is still a major extractive industry. Turning the crude oil into useful products involves huge capital investments at many stages of processing (Figure 7), and the risks facing firms at each stage of processing differ. Historically one way firms have attempted to limit price risk is to integrate their operations from crude oil through final product delivery; however, that strategy is available only to a few very large companies. The rest must turn to other means of managing risk.

There are dozens of domestic spot markets for petroleum products, but in general they tend to be closely linked, because traders quickly take advantage of price differences that do not reflect the marginal cost of transportation. If pipelines are not available to move product, barges and trucks usually are. Consequently, *location arbitrage* generally causes crude oil and petroleum product prices to move together across all the spot markets.[29]

Natural Gas

World trade in natural gas is divided among major regional markets dominated by pipeline infrastructures that provide the means of transporting the gas from producers to consumers and a single worldwide market for liquefied natural gas (LNG). The United States is the largest pipeline gas market. In 2000, the United States produced 19.3 trillion cubic feet of natural gas and consumed 23 trillion cubic feet. The supply gap was covered by 3.2 trillion cubic feet of imports from Canada and 0.5 trillion cubic feet of LNG from the world market. The European countries produced 10.5 trillion cubic feet and

[25]Weather derivatives do not require a spot market for settlement, but they do require objective measurement of the relevant outcomes, such as heating degree days or rainfall totals. "Asian options" average spot prices over a period of time to ensure that the settlements reflect representative market conditions.

[26]See, for example, reports of the rapid escalation of heating oil prices in Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, SR / OIAF / 2000-03 (Washington, DC, May 2000). Also, reports of physical shortage cited there appear in the testimony of Peter D'Arco, SJ Fuel, Before the House Committee on Commerce, Subcommittee on Energy and Power, U.S. House of Representatives (March 9, 2000). A typical reference to natural gas being unavailable following storms appears in Energy Information Administration, *Natural Gas 1992: Issues and Trends*, DOE / EIA-0560(92) (Washington, DC, March 1993), p. 96: "On Tuesday August 25, the Henry Hub, where deliveries through the futures market are made, was closed."

[27]See, for example, a series of articles by staff writer Martin Rosenberg in the *Kansas City Star* during January 1998. The analysis in those articles was challenged in "Kansas Regulator Disputes Report Alleging Spot Market Manipulation," *Inside F.E.R.C.'s Gas Market Report* (April 3, 1998), p. 7. See also S. Borenstein, "The Trouble With Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives*, Vol. 16, No. 1 (Winter 2002), pp. 191-211.

[28]The Brent field is declining, and there have been concerns about the potential for market squeezes. On July 10, 2002, Platts redefined the Brent benchmark to include prices of Forties and Oseberg crude oils.

[29]Arbitrage is not perfect. Several East Coast gasoline markets have a history of price differences that cannot be explained by transportation costs. See for example, K. Bredemeier, "Bargain Hunters Hit the Road," *Washington Post* (October 27, 2001), p. E1.

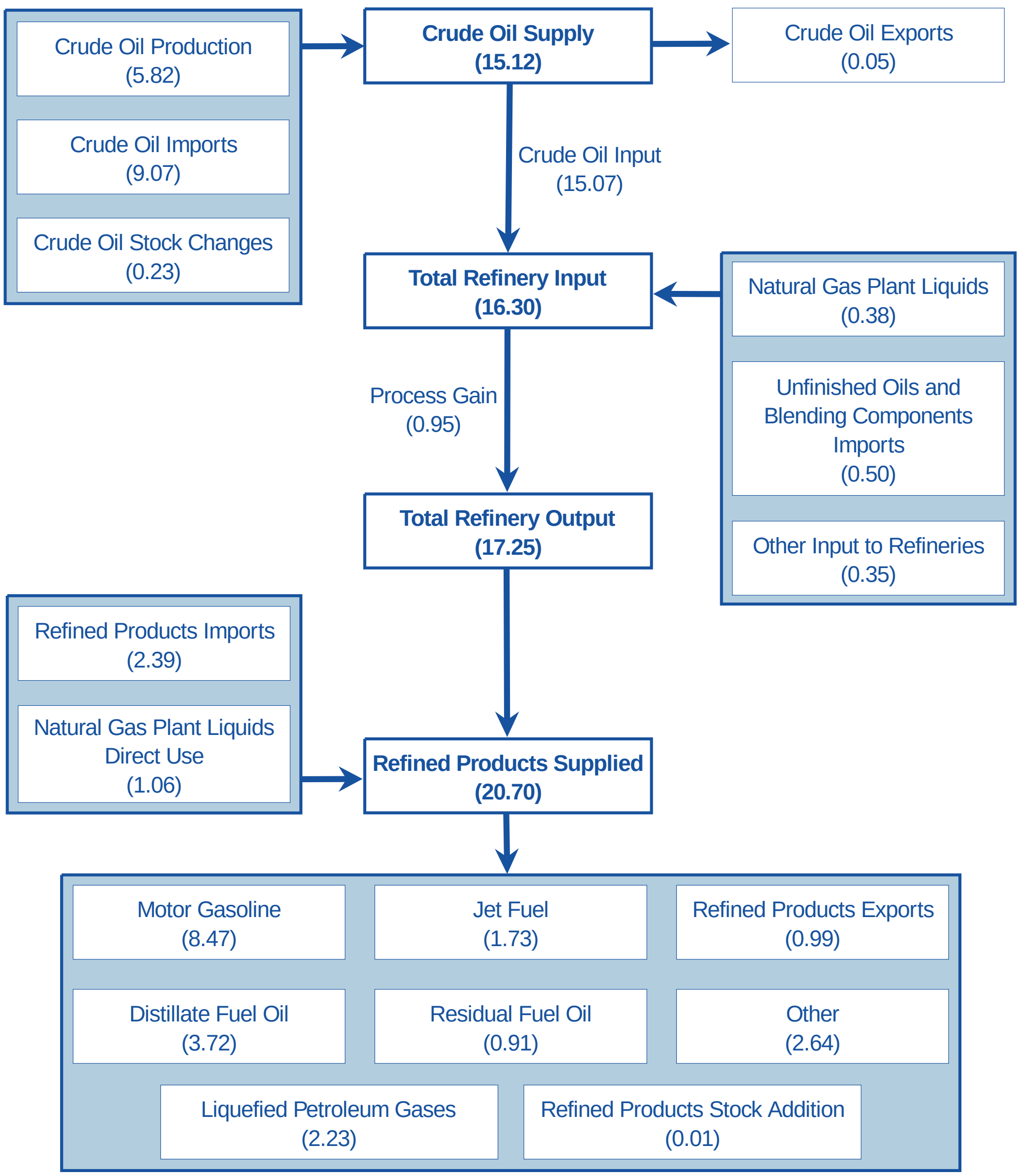
consumed 16.2 trillion cubic feet, with the supply gap covered by Russian imports and small amounts of imported LNG. Russia was the world's largest producer of natural gas in 2000 at 20.3 trillion cubic feet, followed by the United States and Canada. Major exporters of LNG are Indonesia, Malaysia, Australia, Qatar, Oman, Nigeria, and Trinidad. Japan is the largest importer of LNG.

Natural gas production, like oil production, is an extractive industry (Figure 8). Unlike crude oil, however, natural gas requires relatively little processing to be useful. Natural gas is essentially the same everywhere it is sold: there are not dozens of natural gas products. In addition, domestic natural gas reserves are the main source of supply, and transportation is essentially limited to pipelines.

Because natural gas supplies are primarily domestic and international shipments other than with Canada and Mexico are expensive, market and political forces in the United States, Canada, and Mexico mainly determine domestic natural gas prices. Short-term changes in weather—especially extreme weather—can have major effects on natural gas prices. Inventory changes, pipeline capacity curtailments or additions, and equipment outage can also have significant impacts on regional prices.

Natural gas, like electricity, is a network industry in the sense that all suppliers and users are linked by the

Figure 7. Crude Oil Processing Stages, 2000
(Million Barrels per Day)



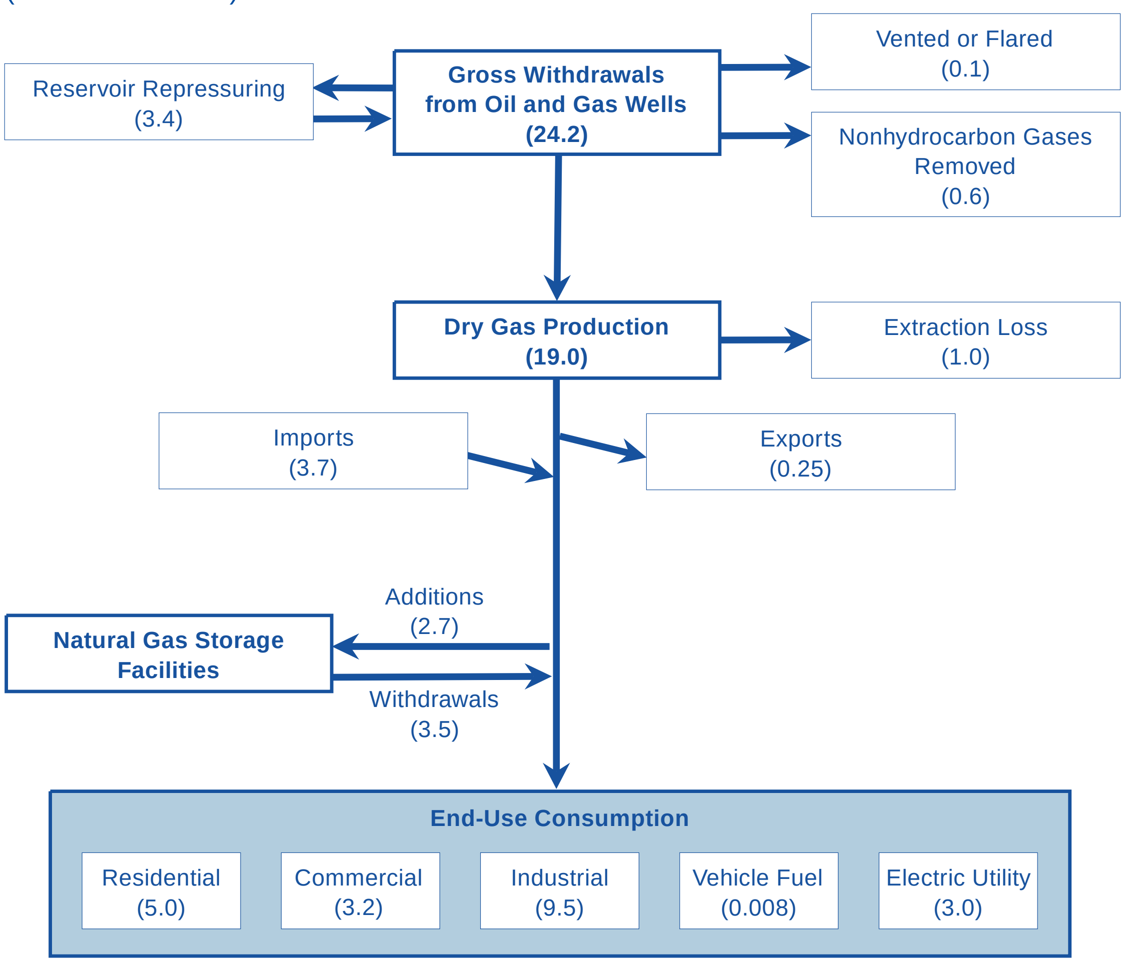
Source: Energy Information Administration, Petroleum and Energy Profile 1999, DOE/EIA-0545(99) (Washington, DC, July 1999), p. 46, updated to 2000 by EIA staff.

physical distribution system for the commodity. Pipelines have no effective competition for moving gas within the United States. Figure 9 shows the general locations served by major pipelines and several of the spot markets (pricing points) that have emerged at major transshipment points (hubs).

Location arbitrage does not work as well for natural gas and electricity as it does for crude oil. Because gas pipelines and power lines have essentially no competitors, frustrated customers cannot buy supplies "off system." In addition, it is difficult to achieve competitive transmission pricing.[30] Consequently, transmission charges are set in noncompetitive markets, with the result that arbitrary price differences between and across markets, not based on marginal costs, can persist in more or less independent, local markets.

Table 6 shows the average daily transmission charges (price differences) for moving natural gas from Henry Hub to 12 local spot markets for the period April 1, 2001, through March 31, 2002. The average price difference ranges from $0.02 below to $0.15 above the Henry Hub spot price.[31] In a competitive market, the transmission charges at different locations would represent the marginal cost of transporting natural gas to each location. If the markets are closely related, the differences in their prices should be stable except for infrequent occasions when capacity is in short supply. This is not the case for natural gas. The standard deviation of the transmission charges listed in Table 6 range from 50 percent to more than 220 percent of the charge itself. That is, the variation in the transmission charge ranges from one-half to twice the average charge itself.

Figure 8. Natural Gas Processing Stages, 2000
(Trillion Cubic Feet)



Source: Energy Information Administration, *Natural Gas Annual 2000*, DOE/EIA-0131(00), (Washington, DC, November 2001).

[30] Competitive pricing of pipeline transportation and electricity transmission could, arguably, be ruinous, because their average costs are greater than their marginal cost unless system utilization is at or near capacity. Most economists argue for tariffs with at least two parts: an access fee to cover capital charges and a transportation charge that reflects marginal operating costs. The heated debates show little sign of ending soon.

[31] A negative transmission charge means that the price is lower at the "receiving" location than at Henry Hub. The negative charge should be interpreted as the charge for moving gas from the cheaper location to Henry Hub.

Natural Gas Spot Markets: How Accurate Are Reported Prices?

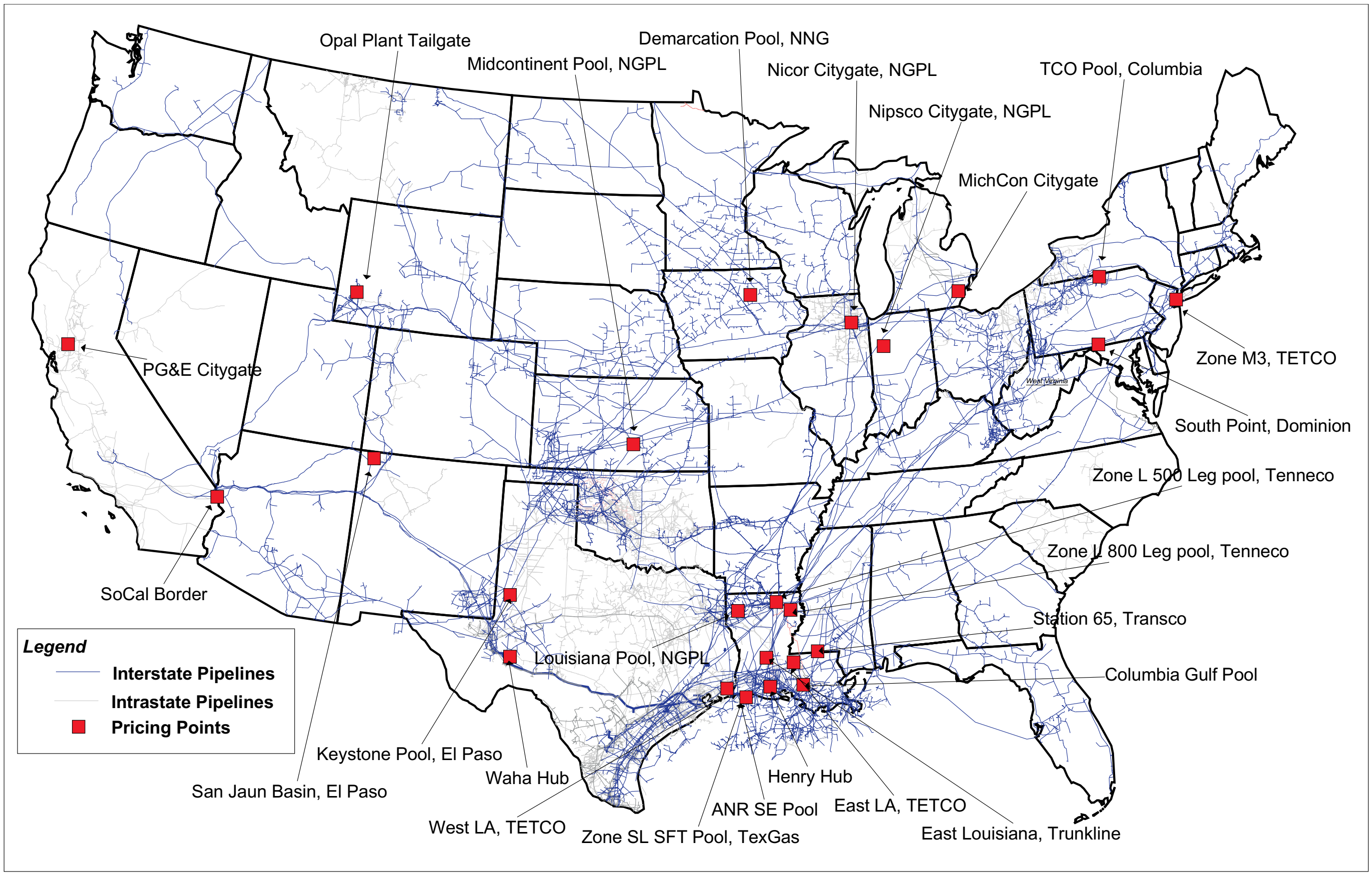
Because spot market prices generally are used to settle contracts, it is crucial that the reported prices accurately reflect market prices. For example, in the case of the New York Stock Exchange, all security sales and prices are recorded and promptly reported, and on most exchanges dealers are required to buy and sell at their posted bids and offers. In the case of natural gas, bids, offers, and prices are collected from traders by reporting firms. Bloomberg Energy Service, for example, reports only bids and offers. But unlike exchange dealers, traders are not required to honor them. Consequently, bids and offers may not be accurate indicators of the actual range of sales prices on natural gas spot markets.

The reporting firms base their price estimates on informal polls of traders. Their responses to a FERC inquiry confirm that traders are under no obligation to report and their reports are not verified except by comparison with other reports. None of the reporting firms publishes the sample sizes or trade volumes associated with their reported prices. Similarly, there is no estimate of total trading volume through the day. Each reporter also has different conventions for defining precisely what is meant by "price."[a] Consequently it is not surprising that the reporters differ as to what the price is at any particular time and place. Indeed, as detailed in Appendix C, the differences in reported prices can be large.

The firms do not assert that the numbers are accurate. The following are typical disclaimers: ". . . [NGI] . . . makes no warranty as to the accuracy of these numbers . . .";[b] and "Platts cannot . . . insure against or be held responsible for inaccuracies . . . ."[c] Accordingly, NYMEX makes provision for traders to protest reported prices that they dispute. Designing risk-sharing instruments when the reported prices are themselves of uncertain quality and the trading volumes are not known is a challenge.

[a]Federal Energy Regulatory Commission, *Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA-02-2-000 (Washington, DC, August 2002), pp. 32-57.
[b]*NGI Daily Gas Price Index* (February 4, 2002), p. 9.
[c]Platts, *Gas Daily* (February 4, 2002), p. 2.

Figure 9. Major Pricing Points (Hubs) for Natural Gas



Source: Energy Information Administration, EIAGIS-NG Geographic Information System.

Table 6. Average Transmission Charges from Henry Hub and Their Standard Deviations

Location	Average Transmission Charge (Dollars per Thousand Cubic Feet)	Standard Deviation	Standard Deviation / Average Transmission Charge
American Natural Resources Pipeline Co. – SE Transmission Pool	0.06	0.03201	0.51
Columbia Gulf Transmission Co. – Onshore Pool	0.03	0.02787	0.87
El Paso – Keystone Pool	0.15	0.11119	0.75
Natural Gas Pipeline Co. of America – Louisiana Pool	0.05	0.03136	0.59
Tennessee Gas Pipeline Co. – Zone L, 500 Leg Pool	0.07	0.04366	0.67
Tennessee Gas Pipeline Co. – Zone L, 800 Leg Pool	0.09	0.04617	0.54
Texas Eastern – East LA	0.05	0.04053	0.84
Texas Eastern – West LA	0.07	0.04134	0.61
Texas Gas Transmission Corp. – Zone SL $FT Pool	0.02	0.02429	1.03
Transcontinental Gas Pipeline Corp. – Station 65	-0.02	0.05230	-2.22
Trunkline Gas Company – East Louisiana Pool	0.09	0.05269	0.57
Waha Hub – West Texas	0.10	0.09210	0.90

Source: Energy Information Administration, computed from data on the IntercontinentalExchange web site, www.intcx.com.

These results suggest that there is not a single domestic natural gas market; instead there is a collection of loosely connected, relatively small spot markets. New pipeline construction and capacity additions should eventually promote more competition in the markets they serve, by relieving the congestion that may account for some of the variation in transmission charges. Until then, market fragmentation will make large trades hard to execute and limit the number of buyers and sellers. It may also encourage attempts to manipulate market prices.

Price Risk and Derivatives in Petroleum and Natural Gas Markets

Diversification and insurance are the major tools for managing exploration risk and protecting firms from property loss and liability. Firms manage volume risk—not having adequate supplies—by maintaining inventories or acquiring productive assets.[32] Derivatives are particularly appropriate for managing the price risk that arises as a result of highly volatile prices in the petroleum and natural gas industries.

The typical price risks faced by market participants and the standard derivative contracts used to manage those risks are shown in Table 7. Price risk in the petroleum and natural gas industries is naturally associated with each participant's stage of production. Some companies integrate their operations from exploration through final sales to eliminate the price risks that arise at the intermediate stages of processing. For example, for an integrated producer, an increase in the cost of crude oil purchased at its refinery will be offset by revenue gains from its sales of crude oil. Other, smaller companies usually do not have integrated operations. Independent

Table 7. Petroleum and Natural Gas Price Risks and Risk Management Strategies

Participants	Price Risks	Risk Management Strategies and Derivative Instruments Employed
Oil Producers	Low crude oil price	Sell crude oil future or buy put option
Petroleum Refiners	High crude oil price	Buy crude oil future or call option
	Low product price	Sell product future or swap contract, buy put option
	Thin profit margin	Buy crack spread
Storage Operators	High purchase price or low sale price	Buy or sell calendar spread
Large Consumers		
Local Distribution Companies (Natural Gas)	Unstable prices, wholesale prices higher than retail	Buy future or call option, buy basis contract
Power Plants (Natural Gas)	Thin profit margin	Buy spark spread
Airlines and Shippers	High fuel price	Buy swap contract

Source: Energy Information Administration.

producers want protection from low crude oil prices, and they sell to refiners who want protection from high prices. Refiners want protection from low product prices, and they sell to storage facilities and customers who are concerned about high prices. At each stage, suppliers and purchasers can split the risk in order to allay their concerns. They typically supplement exchange-traded futures and options with over-the-counter (OTC) products to manage their price risks.

Risk managers in the petroleum and natural gas industries commonly use derivatives to achieve certainty about the prices they pay or receive. Depending on their

[32]In an ideal competitive market, traders would be able to buy as much as they wanted at the market price. In actual markets, large trades sometimes cannot be accomplished quickly at any price. Volume risk recognizes that reality.

circumstance, they may be concerned with the price paid *per se*, with price spreads (differences between prices), with ceilings and floors, and/or with price changes over time. In addition, volumetric production payment contracts—a variant of a standard swap—may be used to reduce uncertainty about cash flows and credit. Some of the instruments particular to the oil and gas industries are described below.

The principal difficulty in using exchange-traded products is they often do not exactly correspond to what the trader is attempting to hedge or to speculate in. For examples, price movements in premium gasoline are not identical to those in unleaded gasoline. Similarly, the price of natural gas at Henry Hub is not identical to that at Chicago. The distinction between what exchange products can hedge and what the user wants to hedge is the source of *basis risk*. Basis risk is the risk that the price difference between the exchange contract and the commodity being hedged will widen (or narrow) unexpectedly. To a large extent, the OTC market exists to bridge the gap between exchange-traded products and the needs of individual traders, so that the two markets in effect have a symbiotic relationship.[33]

Basis Contracts

As described in Chapter 2, price certainty in a unified market can be bought with forward sales, futures contracts, or swaps (contracts for differences). When one or both parties face a spot market price that differs from the price in reference market, however, other derivative contract instruments may be needed to manage the resulting basis risk. For example, a local distribution company (LDC) in Tennessee could enter into a swap contract with a natural gas producer, using the Henry Hub price as the reference price; however, the LDC would lose price certainty if the local spot market price differed from the Henry Hub price (Figure 10). In this example, when the Henry Hub price is higher than the Tennessee price by more than it was at the initiation of the swap contract, the LDC gains, because its payment from the producer will exceed the amount it pays to buy gas in its local market. Effectively, the LDC will pay less per thousand cubic feet than the fixed amount the LDC pays the producer. Conversely, if the Tennessee price is lower, the producer's payment will not cover the LDC's gas bill in its local market.

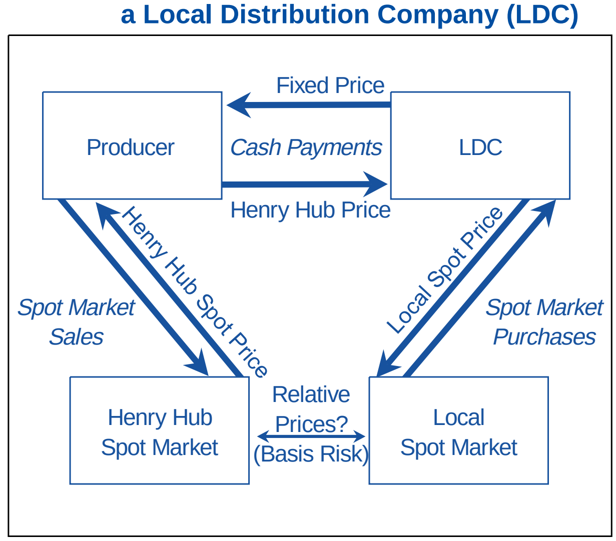
A variety of *basis contracts* are available in OTC markets to hedge locational, product, and even temporal differences between exchange-traded standard contracts and the particular circumstances of contract users. The simplest is a *basis swap*. In the example above, the OTC trader would pay the LDC the difference between the Tennessee price and the Henry Hub price (for the nominal amount of gas) in exchange for a fixed payment. The variety of contractual provisions is unlimited. For example, the flexible payment could be defined as a daily or monthly average (weighted or unweighted) price difference; it could be capped; or it could require the LDC to share the costs when the contract's ceiling price is exceeded. What this OTC contract does is to close the gap between the Henry Hub price and the price on the LDC's local spot market, allowing the LDC to achieve price certainty.

The traders supplying basis contracts can survive only if the basis difference they pay—averaged over time and adjusted for both financing charges and the time value of money—is less than the fixed payment from the LDC. Competition among OTC traders can only reduce the premium for supplying basis protection. Reducing the underlying causes of volatile price differences would require more pipeline capacity, more storage capacity, cost-based transmission pricing, and other physical and economic changes to the delivery system itself.

Crack Spread Contracts

In the petroleum industry, refinery managers are more concerned about the difference between their input and output prices than about the level of prices. Refiners' profits are tied directly to the spread, or difference, between the price of crude oil and the prices of refined products. Because refiners can reliably predict their costs other than crude oil, the spread is their major uncertainty.[34] One way in which a refiner could ensure a

Figure 10. Illustration of a Natural Gas Swap Contract Between a Gas Producer and a Local Distribution Company (LDC)



Source: Energy Information Administration.

[33]See W. Falloon and D. Turner, "The Evolution of a Market," in *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), p. 8: ". . . one of the main reasons the OTC market exists is the desire on the part of end-users to isolate themselves from this basis risk."

[34]Operational risks, such as explosions, are covered with insurance.

given spread would be to buy crude oil futures and sell product futures. Another would be to buy crude oil call options and sell product put options. Both of those strategies are complex, however, and they require the hedger to tie up funds in margin accounts.

To ease this burden, NYMEX in 1994 launched the *crack spread contract*. NYMEX treats crack spread purchases or sales of multiple futures as a single trade for the purposes of establishing margin requirements. The crack spread contract helps refiners to lock in a crude oil price and heating oil and unleaded gasoline prices simultaneously in order to establish a fixed refining margin. One type of crack spread contract bundles the purchase of three crude oil futures (30,000 barrels) with the sale a month later of two unleaded gasoline futures (20,000 barrels) and one heating oil future (10,000 barrels). The 3-2-1 ratio approximates the real-world ratio of refinery output—2 barrels of unleaded gasoline and 1 barrel of heating oil from 3 barrels of crude oil. Buyers and sellers concern themselves only with the margin requirements for the crack spread contract. They do not deal with individual margins for the underlying trades.

An average 3-2-1 ratio based on sweet crude is not appropriate for all refiners, however, and the OTC market provides contracts that better reflect the situation of individual refineries. Some refineries specialize in heavy crude oils, while others specialize in gasoline. One thing OTC traders can attempt is to aggregate individual refineries so that the trader's portfolio is close to the exchange ratios. Traders can also devise swaps that are based on the differences between their clients' situations and the exchange standards.

Crack Spread Options

Some industry participants may be comfortable with price variation so long as prices do not get too high or too low. An LDC that cannot readily pass along natural gas price increases to its residential customers may want to ensure that wholesale prices do not exceed what regulators allow it to charge. Holders of heating oil inventories may want to protect against price declines, but without giving up the opportunity to profit from price increases. As described in Chapter 2 a call option, which allows the holder to buy the commodity at a fixed strike price, sets a price ceiling. A put option, which allows the holder to sell at a fixed price, sets a floor.

NYMEX *crack spread options* are unusual because they protect against the growth or shrinkage in the *difference* between prices. A refiner, fearing that a currently profitable spread will disappear, can buy a crack spread put option. A large user of refined products, fearing that the spread will grow while the price of crude oil is stable, can buy a crack spread call option to compensate for potentially large increases in petroleum product prices when refinery margins grow.

Refiners who use crack spread options pay in advance for the price protection they desire. Options can be expensive when the terms are more favorable to the buyer, and the longer their lifespan, the more they cost. An alternative strategy is for a refiner to simultaneously buy a put and sell a call, so that the cost of the put is offset by the premium earned on the call. In essence, such a *collar* pays for the desired downside protection by selling off the opportunity for a windfall when the crack spread increases.

Calendar Spread Options

Storage facilities play an important role in the crude oil and refining supply chain. Facilities near producing fields allow the producers to store crude oil temporarily until it is transported to market. Facilities at or near refining sites allow refiners to store crude oil and refined products. Heating oil dealers build inventories during the summer and fall for winter delivery. Natural gas storage facilities allow producers to inject excess supply during "shoulder months" for withdrawal during peak demand months and provide producers with the convenience of a shortened injection and withdrawal cycle (a day or a few days), giving the producers and traders the ability to capitalize on the differential between forward prices and spot prices.

For most non-energy commodities, the cost of storage is one of the key determinants of the differential between current and future prices. Although storage plays a smaller role in price determination in some energy markets (most notably, for electricity), it can be important for heating oil and natural gas.[35] For example, natural gas prices in the winter months could be established by the prices in the preceding shoulder months plus storage expenses and an uncertainty premium to account for the possibility of a colder than normal winter. If the price differential between winter months and shoulder months substantially exceeds storage expenses, traders can buy and store gas and sell gas futures. Such arbitrage tends to narrow the price differential.

The owners of storage facilities can use excess capacity both to manage the price risk that often exists between months and to make additional income. Assuming the

[35]Models of heating oil and natural gas markets stress the importance of convenience yield, seasonality, random economic disruptions, and similar factors not included in the simple storage model. See for example, A. Kaushik, V. Ng, and C. Pirrong, "Arbitrage-Free Valuation of Energy Derivatives," in *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), pp. 259-289; and M. Baker, S. Mayfield, and J. Parsons, "Alternative Models of Uncertain Commodity Prices for Use with Modern Asset Pricing Methods," *Energy Journal*, Vol. 19, No. 1 (1998), pp. 115-147.

market is in *contango*—i.e., when near-term prices (for "prompt months" are lower than prices for the months further in the future—owners of underground natural gas storage facilities with excess capacity that can be used to store natural gas for less than the difference between the prices can purchase futures contracts for the prompt months and sell futures contracts for the further future months. The storage facility can then take delivery of the natural gas on the nearby contract and deliver it against the distant contract, earning an arbitrage profit equal to the difference between the sale and purchase of the futures contracts less the facility's cost of storage.

Such arbitrage can also be accomplished by using a *calendar spread call option*. NYMEX offers calendar spread options on crude oil, heating oil, and unleaded gasoline. Buying a call on the calendar spread options contract will represent a long position (purchase) in the prompt months of the futures contract and a short position (sale) in the further months of the contract. Thus, the storage facility can buy a call on a calendar spread that will allow it to lock in a storage profit or to arbitrage a spread that is larger than its cost of storage.

If the market is in *backwardation*—i.e., when the prices for prompt months are higher than the prices for further months—storage facilities with excess capacity cannot arbitrage the calendar spread. In this case, storage facilities can sell put options on calendar spreads to earn income from the option premium. The buyer of a calendar spread put option, when the option is exercised, will receive a short position (sale) in the prompt months of the futures contract and a long position (purchase) in the further months of the contract. Thus, if the storage facility that sold (wrote) the put option is forced to accept delivery because the buyer has exercised the option, it will receive a long position in the prompt futures and a short position in the further futures. If the facility has excess storage capacity, however, it can take delivery on the prompt contract and then deliver on the later dated contract. If the put option is not exercised, the facility can keep the option premium without any further obligation. In summary, storage facilities can use futures contracts and calendar spread options to optimize utilization by arbitraging the difference in the prices specified for different months of a futures contract.

Volumetric Production Payment Contracts

A *volumetric production payment contract* (VPP) is both a prepaid swap and a synthetic loan. Unlike a normal swap, where the differences between the fixed and variable payments are periodically settled in cash, the buyer (usually a producer) is paid the present value of the fixed payments in advance. In exchange, the seller receives an agreed-upon amount of natural gas or other product over time. These deals typically last for 3 to 5 years. VPPs have been purchased by natural gas producers in the past, and in some cases they appear to have been used in project finance.[36] In function, VPPs are identical to loans paid off with product.

The obvious problem with VPPs is that the seller, usually an energy trader, invests a large amount in advance, risking both buyer default and adverse price movements. In addition, VPPs can be used in place of loans to hide debt. What Enron and others often did was to find users of the product who were willing to pay up front in exchange for a price guarantee, use part of those payments to make the advance payment on the VPP, and then hedge their price risks by securing guarantees in the event of default.[37]

Markets for Oil and Gas Derivatives: Organized Exchanges, Trading Firms, and Bulletin Boards

All the contract types discussed above are bought and sold in markets, both public and private. Exchanges, energy traders, and electronic bulletin boards compete vigorously for business in energy derivatives, and investment banks and insurance companies have also participated. Society relies on competition within and across these markets to ensure that risk is transferred at least cost. The exchanges and OTC traders have designed derivatives that respond to the concerns of market participants while recognizing the limits of location arbitrage, the importance of input-output price spreads to profits, and the role of price controls in retail natural gas markets.

Successful petroleum futures contracts first appeared in 1978, when NYMEX introduced futures contracts on both No. 2 heating oil and No. 6 fuel oil. The No. 6 contract failed because utilities, the largest purchasers of No. 6 fuel oil, were able to pass the risk of escalating prices on to their customers by means of fuel adjustment clauses; therefore, they did not need the futures market to minimize price risk. The No. 2 contract has been successful, however, because heating oil is bought and sold by a large number of market participants. The heating oil market is also active year-round: inventories are built up in the off season and worked off in the winter to meet seasonal demands.

Trading volume in a successful contract can climb dramatically. For example, the annual trading volumes of the No. 2 heating oil contract grew from 25,910 in 1978 to

[36] *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), pp. 159 and 11.
[37] C. Johnson and P. Behr, "Loans Hidden, Enron Probers Say," *Washington Post* (July 22, 2002), p. A9.

more than 932,000 in 1980, to 5.7 million in 1989,[38] and to a record 9.6 million in 2000.

NYMEX has become the dominant market for energy futures and options trading, with 73,701,461 futures contracts and 15,445,318 options contracts traded in 2001 (Tables 8 and 9). The largest contract by volume is the light sweet crude oil futures contract, which began trading in 1983 and had over 37 million contracts traded in 2001. Other heavily traded futures contracts include heating oil, natural gas (introduced in 1990), and unleaded gasoline (introduced in 1984). The propane futures contract (introduced in 1987) is much less heavily traded but remains an active market.

As discussed in Chapter 2, all exchange contracts are standardized. Standardization focuses all bidding on price, thereby maximizing market liquidity and minimizing transaction costs. Table 10 shows the specifications for the light sweet crude oil contract as an example. The details defining standard contracts determine their usefulness to traders.

Because futures contracts specify delivery at a particular location, traders desiring delivery or price protection at other locations must contend with "basis differential." In the case of natural gas, the basis differential is the cost of transporting the gas from Henry Hub to the location in question. There are no exchange-traded products to deal with this basis risk. Consequently producers in this and analogous circumstances looked to the OTC market, especially energy traders, for hedging instruments.

Although energy trading firms have played an important role in helping energy businesses manage basis and other risks, they have fallen from prominence in the last year. Table 11 lists the top oil and natural gas traders as of the third quarter of 2001 and reports their credit status as of mid-2002. The outlook for these firms is uncertain. Moody's Investor Services, for one, is not sanguine:

> *Moody's believes that energy trading, as presently configured, may lack investment grade characteristics unless it is ancillary to a more stable core business that generates strong sustainable cash flow. The typical business model marries a Baa-caliber energy producer and distributor with a volatile, confidence-sensitive trading operation. A negative credit event, either in the core business or in the trading segment—resulting in even a modest rating downgrade—can trigger a significant call on cash. Moreover, the lack of regulatory oversight and the opaque accounting are not conducive to*

Table 8. Summary Statistics for Exchange-Traded Petroleum and Natural Gas Futures Contracts

Exchange	Commodity	Point of Delivery	Contract Size	Futures	Date Begun	2001 Annual Volume (Contracts)	2002 Estimated Volume on April 17, 2002 (Contracts)
NYMEX	Heating Oil	New York Harbor	42,000 Gallons	18 Months	11/14/1978	9,264,472	31,831
NYMEX	Natural Gas	Henry Hub, LA	10,000 Million Btu	72 Months	04/03/1990	16,468,355	105,522
NYMEX	Light Sweet Crude Oil	Cushing, TX	1,000 Barrels	30 Months + 5 Long	03/30/1983	37,530,568	240,823
NYMEX	Unleaded Gasoline	New York Harbor	42,000 Gallons	12 Months	12/03/1984	10,427,500	43,854
NYMEX	Propane	Mont Belvieu, TX	42,000 Gallons	15 Months	08/21/1987	10,566	6
KCBOT	Western Natural Gas	Permian Hub, West Texas	10,000 Million Btu	18 Months	08/01/1995	0	0

Source: New York Mercantile Exchange (NYMEX) and Kansas City Board of Trade (KCBOT).

Table 9. Summary Statistics for Exchange-Traded Petroleum and Natural Gas Options Contracts

Exchange	Commodity	Options	Date Begun	2001 Annual Volume (Contracts)	2002 Estimated Volume on April 17, 2002 (Contracts)
NYMEX	Heating Oil	18 Months	06/26/1987	704,972	2,034
NYMEX	Natural Gas	12 Months + 20 Long	10/02/1992	5,974,240	39,660
NYMEX	Light Sweet Crude Oil	12 Months + 3 Long	11/14/1986	7,726,076	65,688
NYMEX	Unleaded Gasoline	12 Months	03/13/1989	1,040,030	5,674
KCBOT.	Western Natural Gas	18 Months	08/01/1995	0	0

Source: New York Mercantile Exchange (NYMEX) and Kansas City Board of Trade (KCBOT).

[38]C. Dale, "Economics of Energy Futures Markets," in Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(91/09) (Washington, DC, September 1991), p. 6.

maintaining counterparty confidence . . . . We believe that a fundamental restructuring will need to occur in the near term for this sector to regain investor confidence.[39]

How this sector will evolve is unknowable. Investment banks might return to a prominent role in energy markets. As William Falloon and David Turner have noted, "Energy companies . . . argue that banks have a permanent disadvantage arising from their lack of knowledge of inventories and other aspects of the physical market. Even so, those banks still in the market seem to be thriving."[40] Insurance companies also have the financial reserves to withstand inevitable market setbacks and may become more interested in applying their expertise to energy markets. Moody's suggests that either industry consolidation into a few well-capitalized companies, the development of a clearing system, or the creation of derivative product companies that are near bankruptcy-proof would restore this group of competitors.

The Internet is responsible for the latest innovation in energy trading. In November 1999, EnronOnline was launched to facilitate physical and financial trading. EnronOnline was a principal-based exchange in which all trades were done with Enron as the counterparty. As a consequence, Enron's perceived creditworthiness was crucial to its ability to operate EnronOnline.

After the launch of EnronOnline, several other online exchanges quickly followed, including Intercontinental-Exchange (ICE), which was backed by major producers and financial services companies, and TradeSpark, which was backed by major electric utilities, traders, and gas pipeline companies. Both ICE and TradeSpark provide electronic trading platforms offering registered users anonymity for posting prices and executing trades. Unlike EnronOnline, they do not take trading positions. ICE offers swaps on crude oils other than Brent and WTI and on refined products in numerous locations, to complement the futures contracts trading of

Table 10. NYMEX Light Sweet Crude Oil Contract Specifications

Trading Unit	1,000 U.S. Barrels (42,000 gallons).
Trading Hours	Open outcry trading conducted between 10 am till 2:30 pm. NYMEX ACCESS@ on Mon-Thu begins at 3:15 pm and concludes 9 am the following day. Sunday ACCESS begins at 7 pm (all times are New York).
Trading Months	30 consecutive months plus long-dated futures initially listed 36, 48, 60, 72, and 84 months prior to delivery. Additionally, calendar strips can be executed (during open outcry trading hours) at an average differential to the previous day's settlement prices for periods of 2 to 30 consecutive months in a single transaction.
Price Quotation	Dollars and cents per barrel.
Minimum Price Fluctuation	$0.01 per barrel (i.e., $10 per contract).
Maximum Daily Price Fluctuation	Initially $3.00 per barrel for all but the first two months, rising to $6.00 per barrel if the previous settlement price of any back month is at the $3.00 limit. If $7.50 per barrel movement in either of the two front months, then the limit for all months becomes $7.50 per barrel in the direction of the price movement.
Last Trading Day	Trading stops at close of business on the 3rd business day prior to the 25th calendar day of the month preceding the delivery month. If 25th is a non-business, then trading stops on 3rd business day prior to last business day preceding the 25th.
Delivery	FOB seller's facility, Cushing, OK, at any pipeline or storage facility with access to pipeline, by in-tank transfer, in-line transfer, book-out, inter-facility transfer.
Delivery Period	Deliveries are rateable over the course of the month and must be initiated on or after the first calendar day and completed by the last calendar day of the delivery month.
Alternative Delivery Procedure	Available to buyers and sellers matched by the Exchange after termination of spot month contract. If buyer and seller agree to the contract specifications, they may proceed and must notify the Exchange.
Exchange of Futures for Physicals (EFP)	Commercial buyer or seller may exchange a futures position for a physical position by notifying the Exchange. EFPs may be used to initiate or liquidate a futures position.
Deliverable Grades	Specific domestic crudes with 0.42% sulfur or less, and not less that 37 degree API gravity nor more than 42 degree API gravity; including WTI, Low Sweet Mix, NM Sweet, North TX Sweet, OK Sweet, South TX Sweet. Specific foreign crudes not less than 34 degree API nor more than 42 degree API; including Brent, Forties, and Osenberg Blend for which the seller will receive a 30 cent per barrel discount; Bonny Light and Cusiana (a 15 cent premium); and Qua Iboe (a 5 cent premium).
Inspection	Will be conducted according to pipeline practices. Buyer or seller may appoint an inspector and the requesting party will cover the cost and notify the other party.
Position Limits	20,000 contracts for all months combined, but not to exceed 1,000 in the last 3 days of trading in the spot month or 10,000 in any one month.
Margin Requirements	Margins are required for open futures positions.

Source: New York Mercantile Exchange (NYMEX), web site www.nymex.com.

[39] P. Stumpp, J. Diaz, D. Gates, S. Solomon, and M. Hilderman, Moody's Investors Service, *Moody's View on Energy Merchants: Long on Debt—Short on Cash Flow: Restructuring Expected*, Special Comment (May 2002).

[40] W. Falloon and D. Turner, "The Evolution of a Market," in *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), p. 2.

NYMEX and the International Petroleum Exchange (IPE). The bulletin boards also are doing a brisk business in physical trades, despite the fact that several have ceased operations in recent months.

Use of Derivatives by Firms in the Petroleum and Natural Gas Industries

There is little quantitative information available on the extent to which derivative contracts are used by individual firms and utilities. Some academics have conducted large, voluntary surveys on the use of derivatives, but their results are far from definitive because of a lack of statistical sampling, among other problems. New information about the use of derivatives is just now appearing on firms' SEC 10K filings, but those filings do not provide much in the way of details. The following sections summarize the data that are available from academic research on the benefits that oil and gas producers and natural gas pipelines gain from using derivatives and the newly available data from the SEC Form 10K.

Academic Research

G. David Haushalter has examined the risk management activities of 100 oil and gas producers in 1992, 1993, and 1994.[41] He attempted to relate the extent of different firms' hedging activity to their capital structure (debt/equity ratio, interest coverage, etc.), tax status, compensation policies, ownership structure, and operating characteristics. He found the following:

- The presence of hedging activity increased from 43 percent of the firms in the sample in 1992 to 57 percent in 1994. About one-quarter of the firms surveyed hedged more than 28 percent of their production. Hedgers as a group hedged about 24 percent of their total production.
- Companies with more assets were more likely to hedge.
- Hedgers with larger proportions of debt in their capital structure hedged a greater fraction of their production.
- Hedging was more likely for firms whose local spot market prices closely followed the Henry Hub (natural gas) or Cushing (sweet crude) spot prices used in NYMEX futures. In other words, the lower the basis risk, the more likely a firm was to hedge.
- There was no clear relationship between managers' compensation and hedging.

Haushalter interpreted his findings as being ". . . consistent with the notion that hedging enables companies to

Table 11. Moody's Bond Ratings for the Top 20 Natural Gas Marketers, 2000-2002

Company	2002		2001		2000	
	Date	Rating	Date	Rating	Date	Rating
1 Enron	NR	NR	03 DEC 2001	Ca	23 MAR 2000	Baa1
2 Reliant Energy	NR	NR	27 APR 2001	Baa2	20 MAR 2000	Baa1
3 American Energy Power	19 APR 2002	Review For Downgrade	24 APR 2001	Baa1	15 JUN 2000	Baa2
4 Duke Energy	NR	NR	21 SEP 2001	A2	NR	NR
5 Mirant	NR	NR	19 DEC 2001	Ba1	16 OCT 2000	Baa2
6 BP Energy (tied)	NR	NR	NR	NR	NR	NR
6 Aquila (tied)	20 MAY 2002	Review For Downgrade	NR	NR	13 DEC 2000	Baa3
8 Dynergy	25 APR 2002	Review For Downgrade	14 DEC 2001	Baa3	26 OCT 2000	Baa2
9 Sempra	22 APR 2002	Review For Downgrade	25 JUN 2001	A2	17 FEB 2000	A2
10 Coral	27 MAR 2002	A1	NR	NR	14 AUG 2000	A1
11 El Paso	29 MAY 2002	Baa2	12 DEC 2001	Baa2	31 JAN 2000	Baa2
12 Conoco (tied)	NR	NR	16 JUL 2001	Baa1	21 FEB 2001	A3
12 Entergy-Koch (tied)	NR	NR	19 JUL 2001	A3	NR	NR
14 Texaco	NR	NR	10 OCT 2001	A2	NR	NR
15 Dominion Resources	NR	NR	24 OCT 2001	Baa1	24 AUG 2000	Baa1
16 Williams	7 JUN 2002	Baa3	19 DEC 2001	Baa2	NR	NR
17 Exxon Mobil (tied)	NR	NR	NR	NR	NR	NR
17 Anadarko (tied)	30 JAN 2002	Baa1	24 JUL 2001	Baa1	17 JUL 2000	Baa1
19 Oneok (tied)	NR	NR	03 DEC 2001	Review For Downgrade	14 FEB 2000	A2
19 TXU (tied)	NR	NR	30 MAR 2001	Aaa	13 MAR 2000	Baa3

Rating Definitions: Aaa, Issuers rated Aaa offer exceptional security; Aa, Issuers rated Aa offer excellent financial security; A, Issuers rated A offer good financial security; Baa, Issuers rated Baa offer adequate financial security; Ba, Issuers rated Ba offer questionable financial security; B, Issuers rated B offer poor financial security; Caa, Issuers rated Caa offer very poor financial security; Ca, Issuers rated Ca offer extremely poor financial security; C, Issuers rated C are the lowest-rated class of entity; NR, No Rating.

Note: Moody's applies numerical modifiers 1, 2, and 3 in each generic rating category from Aa to Caa. The modifier 1 indicates that the issuer is in the higher end of its letter rating category; the modifier 2 indicates a mid-range ranking; the modifier 3 indicates that the issuer is in the lower end of the letter ranking category.

Source: Web site www.moodys.com (June 26, 2002).

[41] G.D. Haushalter, "Financing Policy, Basis Risk, and Corporate Hedging: Evidence from Oil and Gas Producers," *Journal of Finance*, Vol. 55, No. 1 (February 2000); and "Why Hedge? Some Evidence from Oil and Gas Producers," *Journal of Applied Corporate Finance*, Vol. 13, No. 4 (Winter 2001).

reduce their dependence on the capital markets to finance investment projects. It also supports the idea that managers hedge to reduce the likelihood that the company will encounter financial distress. Under either of these interpretations, theory suggests that corporate hedging could increase shareholder value."[42]

Géczy, Minton, and Schrand have studied how natural gas pipelines used a variety of risk management tools—including cash reserves, storage, diversification, and derivatives (when available)—from 1978 through 1995.[43] They selected all major natural gas companies that were (or had) major interstate natural gas pipelines. At the beginning of deregulation (1979), natural gas sales made up 60 percent of the total sales for the companies surveyed. By 1995, gas sales made up about 8 percent of the companies' total sales, reflecting the new role of pipelines as common carriers rather than merchants of natural gas.

A major risk for pipelines is that they will not be able to deliver enough gas to meet demand. One way in which they address volume risk is by storing large quantities of gas near their markets. Another risk is fluctuating demand for transport: when demand is low, transport prices usually are low; when demand is strong, both natural gas prices and transportation rates usually are high. Consequently, even though pipelines no longer marketed significant volumes of gas by the early 1990s, their revenues were directly correlated with the price of natural gas.

The research strategy used by Géczy et al. was first to describe any changes in how firms use cash, storage, diversification, and derivatives over the period. Next they measured the sensitivity of each firm's stock price to natural gas prices. Then they examined the differences between firms with high and low sensitivity to natural gas prices. Their findings about trends in risk management practices include the following:

- There was no clear trend in cash holdings or storage policy over the time period.
- Pipelines did not use derivatives in the early years of deregulation, but by 1993 about 83 percent of the selected firms used derivatives.

They also found that hedging was effective:

- Cash holdings, storage, and line-of-business diversification all lowered the sensitivity of stock returns to natural gas price.
- Users of commodity derivatives had smaller and less variable stock price sensitivities than did non-users.
- Storage was used to hedge volume risk. Derivatives were used to manage price risk.

Like Haushalter, Géczy et al. found that derivative users had lower bond ratings and dividend yields than did non-hedgers.

SEC 10K Filings

Because there are no academic studies of how LDCs and storage facilities use derivatives, the newly available 10K data were examined for this study to see whether and how such firms use derivatives. As is noted in Chapter 7, firms are now required to report in their 10K filings to the SEC the "fair value" of their derivative holdings on their balance sheets and the change in the fair value on their income statements.

The fair values of the derivative holdings of the 27 largest natural gas and electricity marketers are shown in Table 12.[44] Note that these derivative holdings are reported as both assets and liabilities. In publicly traded companies' quarterly and annual reports, a positive change in the value of a derivative is classified as an asset on the balance sheet, and a negative change is classified as a liability (see Chapter 7 for a discussion of accounting for derivatives). If a firm judges that the fair value of its derivative holdings is "not material," their value is not reported as a separate line item on the balance sheet. Across the 27 companies, the values of financial derivative assets and liabilities are roughly the same size.

Perhaps the most striking result shown in Table 12 is the wide variation in the value of the firms' derivative holdings. Information from their financial reports indicates that all the firms did indeed use derivatives to hedge; however, the value of their holdings varied from an amount so small that it was "not material" to about $20 billion.[45]

[42] G.D. Haushalter, "Why Hedge? Some Evidence from Oil and Gas Producers," *Journal of Applied Corporate Finance*, Vol. 13, No. 4 (Winter 2001), p. 92.

[43] C. Géczy, B.A. Minton, and C. Schrand, "Choices Among Alternative Risk Management Strategies: Evidence from the Natural Gas Industry," working paper (University of Pennsylvania, Wharton School of Economics, 2002).

[44] "Fair value" is not the same as "notional value." Fair value is an estimate of a contract's worth under current conditions. Notional value is the size of the position. Fair value at contract initiation is zero. If prices do not change much during the contract's life, fair value can remain near zero even if notional value is large.

[45] Although $20 billion appears to be large, it is small in relation to firms in other industries. For example, Fannie Mae, a large corporation that provides a secondary market for mortgages, has derivative holdings valued at just under $500 billion, and the derivative holdings of Morgan Stanley, a large investment bank, are about $60 billion.

The financial reports of large oil and natural gas producers and petroleum refiners were also examined. All but one of the firms indicated that they did use derivatives to hedge. In virtually all cases, however, the fair value of their holdings was not reported as a separate line item, implying that their holdings were "not material." It would therefore appear that marketers use derivatives more than producers and refiners do. Interestingly, in a number of cases, several petroleum firms indicated that they were vertically integrated and had limited need to hedge.

The U.S. General Accounting Office is in the process of surveying derivative use by a few hundred natural gas distribution companies. Although the results of that survey will not be available until September 2002, preliminary reports indicate that some LDCs are using derivatives to manage price risk.

Table 12. Use of Derivatives by Large Energy Marketing Firms, 2002
(Million Dollars)

Company	Derivative Assets	Derivative Liabilities	Total Assets	Derivative Assets as a Fraction of Total Assets
Reliant	2,058	1,840	5,989	0.344
American Electric Power	10,942	10,494	53,350	0.205
Duke Energy	5,443	3,731	19,478	0.279
Mirant	4,703	2,033	22,754	0.207
BP Energy	NR	NR	105,050	NR
Aquala	1,261	1,503	11,948	0.106
Dynergy	6,336	10,739	19,659	0.322
Sempra	2,575	1,793	15,156	0.170
El Paso	692	214	19,066	0.036
Conoco	221	NR	27,904	0.008
Entergy	2,089	1,982	25,910	0.081
Texaco	NR	NR	18,327	NR
Dominion Resources	1,856	1,408	34,369	0.054
Williams	10,724	8,462	38,906	0.276
ExxonMobil	NR	NR	26,461	NR
Anadarko	105	207	16,771	0.006
Oneok	1,063	873	7,441	0.143
Texus Utilities	2,447	2,049	42,275	0.058
Aquila	1,261	1,503	11,948	0.106
PG&E	807	711	19,554	0.041
Exelon	NR	NR	26,461	NR
Allegheny	NR	NR	NR	NR
Constellation Energy	2,218	1,800	14,078	0.158
Calpirie	1,328	1,448	21,309	0.062
CMS Marketing	885	733	17,102	0.052
Edison Mission	68	193	10,730	0.006
First Energy	NR	NR	37,351	NR

NR = Not reported as a line item on the company's balance sheet.
Source: Securities and Exchange Commission Form 10K filings, web site www.sec.com (June 26, 2002).