# 5. Prospects for Derivatives in Energy Industries

## Introduction

Derivatives have proven to be useful in the petroleum and natural gas industries, and they still are being used in the electricity industry despite the setbacks discussed in Chapter 4. They probably would be used more extensively if financial and market data were more transparent. Managers may limit derivative use because their presence in company accounts is troubling to some classes of investors. In addition, the lack of timely, reliable spot price and quantity data in most markets makes it difficult and expensive for traders to provide derivatives to manage local risks. The prospects for the growth of an active electricity derivatives market are tied to the course of industry restructuring. Until the electricity spot markets work well, the prospects for electricity derivatives are limited.

## Transparency of Financial Information

The crucial question to be asked about the new Statement 133 from the Financial Accounting Standards Board (FASB) for reporting derivatives is whether the guidelines for corporate financial reporting of derivatives are sufficient for investors to understand the risks companies are taking.[74] Two aspects of accounting practice will be particularly important in determining the answer to that question: estimation of the fair value of derivatives and the scope of accounting for them.

### Fair Value Estimation

The issue of transparent commodity prices and determining the value of derivative contracts will also have implications with respect to how they are reported on a firm's financial statements. Most important, derivatives are to be recognized in financial statements at fair value. The guidance from Statement 133 on measurement of fair value states that, "Quoted market prices in active markets are the best evidence of fair value and should be used as the basis for the measurement, if available." The Statement recommends that when market prices are unavailable—as, for example, in an over-the-counter (OTC) forward contract—fair value should be estimated ". . . based on the best information available in the circumstances." The Statement allows for the use of valuation techniques, stating that, "Those techniques should incorporate assumptions that market participants would use in their estimates of values, future revenues, and future expenses, including assumptions about interest rates, default, prepayment, and volatility."[75]

Market prices are readily available for futures contracts traded on exchanges and for traded options; however, futures markets account for a minority of energy derivatives activity in the United States. OTC forward contracts and other OTC energy derivatives not only are the major form of energy derivatives but also have been the most rapidly growing. In the case of electricity derivatives, OTC forward contracts are the most commonly used, particularly after the cessation of trading in electricity futures contracts on the New York Mercantile Exchange (NYMEX). Fair value measurement is clearly a concern as the United States moves toward greater deregulation of electricity and a corresponding increase in the use of OTC derivatives in the electricity sector.

In the absence of market price information, guidance provided by Statement 133 appears to be quite general. The documentation required for hedge accounting could contain enough description of fair value estimation to allow a reasonable assessment by investors of the prudence of the methods used; however, rigorous documentation is not required for non-hedge derivative accounting. Perhaps materiality criteria might induce disclosure of valuation methods for non-hedge holdings of derivatives. For example, if changes in fair value totaled more than 5 percent of net income, companies might be required to provide detailed disclosure of their valuation techniques. Valuation techniques may be the subject of future opinions and standards issued by the accounting authorities.

### Scope of Derivatives Accounting

Statement 133 has broadened the scope of what is included as a derivative. According to an expert accountant in risk management, "If you are buying or selling energy in the wholesale commodity market, whether you hedge or not, assume this is a derivative unless proven otherwise."[76] Most contracts for future purchase

[74]Chapter 7 of this report provides a review of Statement 133.

[75]Financial Accounting Standards Board, Statement 133, "Accounting for Derivative Instruments and Hedging Activities," pp. 272-273.

[76]David Johnson, quoted in "Protecting Your Earnings: Managing the FASB 133 Challenge," supplement to *Hart's Oil and Gas Investor* (February 2001), p. 2.

or delivery of energy commodities will be considered derivatives unless they qualify for the "normal purchase or sale exception." If a contract is an energy derivative, then mark-to-market valuation of the contract will be used, and the change in fair value will be reported quarterly.

Some contracts for future purchase or delivery of energy commodities can have long periods of performance. Contracts for natural gas or power stretching over 10 years are not rare in the United States. Some liquefied natural gas (LNG) projects that involve heavy investment in natural gas production and processing for transport to distant destinations are based on long-term contracts that can have terms lasting up to 20 years. If the future deliveries in the contract can be settled on a net basis even though delivery is expected by the contracting parties, then the contract could be treated as a derivative if the normal purchases and sales exception is not elected through documentation. Long-term contracts for energy commodities not documented as normal sales and purchases could be reportable as derivatives and carried on company balance sheets at fair value under Statement 133. Further, at inception, the contract's estimated fair value would be recognized in current earnings, on an amortized basis.

This treatment of long-term energy commodity contracts could be problematical. First, there may be time spans of several years between inception of a long-term contract and expected delivery of an energy commodity. Recognition on the balance sheet of the fair value of such a contract at its inception does not convey the uncertainty that accompanies the long lead times to first delivery. Second, such contracts are sparsely traded, if traded at all, and typically do not have market values. Fair value will have to be estimated by market valuation techniques. Given the long lead times and lengthy periods of performance of long-term energy contracts, the variance surrounding such estimates is likely to be so large as to seriously impair their credibility.

Another effect of the wider scope of derivatives and consequent increased application of mark-to-market pricing will be greater volatility in reported earnings and stockholders' equity. It appears possible that improved reporting of derivatives (which are often used to reduce earnings volatility) through Statement 133 might increase the apparent volatility of earnings. Greater volatility in earnings and shareholders' equity can complicate investors' efforts to review and assess companies' financial disclosures. The same problems might also complicate ratemaking and regulatory review for pipelines and electric power. The Federal Energy Regulatory Commission (FERC) has recently proposed incorporation of significant parts of Statement 133 into a number of reports filed with the Commission.

## Financial Reporting and Abuse of Derivatives: Some Recent Examples

The story of derivatives in the energy industry and the accounting for them is incomplete without an examination of the ways in which Enron and other companies have used derivatives for purposes other than risk management, such as managing reported earnings, and for other financial engineering goals, such as hiding debt. Such accounting and financial engineering objectives may have been responsible for at least some of the explosive growth in the derivatives markets in the late 1990s. Some examples of how Enron and other energy traders have used energy derivatives to manage earnings and hide debt are provided below.

### Managing Earnings Using Derivatives Valuation

As energy companies expanded their role from being just producers and distributors to become energy traders as well, they found increased opportunities to use derivatives for earnings management. The main reason for this development is the accounting requirement of mark-to-market accounting for derivatives. As discussed in Chapter 7, the accounting rules require all financial contracts, even those energy derivatives that are not actively traded in the futures markets, be marked up or down to their estimated market values on the balance sheet. For complex, non-traded derivatives, companies must develop theoretical valuation models describing the derivatives' value over time, make appropriate assumptions about model variables (such as price curves and demand), and compute the value.

For long-term derivatives, mark-to-market gains typically are non-cash; the actual cash flows may not be realized for several years. Consequently, a company may report large accounting earnings while at the same time consuming large amounts of cash flow. Investors can get some feel for this phenomenon by examining the difference between "earnings" and "cash flow from operations" (CFO) reported in companies' cash flow statements. Consider, for example, the following data for net income and CFO for Enron for the year 2000, compiled from its quarterly filings with the Securities and Exchange Commission (SEC).

| Item | Stated Value (Million Dollars) | | | | |
|---|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 | Annual |
| Net Income | 338 | 289 | 292 | 60 | 979 |
| Cumulative Net Income | 338 | 627 | 919 | 979 | |
| Cash Flow from Operations | -457 | -90 | 647 | 4,679 | 4,779 |
| Cumulative Cash Flow | -457 | -547 | 100 | 4,779 | |

As shown, Enron reported large and positive net income in each of the quarters during 2000, but its cumulative

CFO was negative or negligible for most of the period. Transactions completed in the fourth quarter (often in December) made the cash flow positive for the year on a cumulative basis. The same pattern was also apparent for the company's net income in 1997, 1998, and 1999. Cash flow "red flags" such as these often suggest, although they do not provide conclusive proof, that an energy company might be managing its reported earnings by using mark-to-market gains from derivatives.

The mark-to-market valuation data provided to analysts by another large energy trader, The Williams Companies, show the extent of flexibility available to management in reporting mark-to-market gains. Williams reported that, as of the end of 2001, the gross unrealized cash future flows from its derivative contracts were $7.82 billion.[77] It then used its subjective *risk assessment* of the contracts to determine the appropriate discount rates to use over the terms of the contracts and applied the discount rates to determine the net present value (NPV) of future cash flows as $3.03 billion. Next, it made additional *credit adjustment* provisions to account for the specific and known riskiness of its counterparties and reduced the NPV to $2.12 billion. Finally, it made a *valuation adjustment* to the contracts for additional unspecified risks, and further reduced the recognized value of the contracts to $1.37 billion, which was the amount reported in its financial statements.

Although Williams clearly was conservative in assessing the value of its derivative holdings, the data point to the enormous flexibility inherent in the valuation process in taking a $7.82 billion gross cash flow down to the reported $1.37 billion value. Critics have said that Enron's traders used these and other so-called *prudency reserves* that were not recognized in the company's accounting systems to subjectively set aside the value of gains and losses on contracts from one period for potential use in a later period.

This example makes clear that the potential for earnings management using derivatives is higher when the derivative contracts are long-term in nature. In addition, the potential for earnings management increases when derivatives are entered into for trading or speculative purposes rather than for pure economic hedging, which would require a corresponding valuation assessment and valuation management for the hedged item as well.

## Hiding Debt Using Derivatives

Consider the example of a hypothetical energy company with a prepaid forward contract to deliver natural gas to an entity one year from now. The company receives $1 million in cash up front and takes on a liability to deliver the gas. Also assume that, simultaneously, the company enters into a cash-settlement forward contract with another entity, in which it agrees to buy the same amount of gas as specified in the first contract one year from now and pay cash on delivery for $1.06 million. Both contracts are derivatives, and they may well be legitimate financial transactions with goals such as risk management. But what if the counterparty for each of the two contracts is effectively the same? For example, both might be wholly owned entities of the same company. Canceling out the gas delivery and gas purchase, we are left with what looks like a $1 million loan transaction with an interest rate of about 6 percent. Published media articles show that Enron and several other energy companies may have abused long-term derivatives in this way to raise billions of dollars of loans and hide them from shareholders and other creditors.

It is important to note that the loan raised in the above example is not a case of an "off balance sheet" item. In fact, the loan is fully disclosed on the balance sheet. However, it is not reported in a visible way as a loan. Instead, it is hidden on the balance sheet by being submerged into another liability line, called "price risk management activities" (PRM). Because energy traders typically would have very large PRM assets and liabilities arising from their legitimate trading portfolios, it would be impossible for an investor to know whether the PRM also includes loans.

The magnitude of the PRM item on energy traders' balance sheets is usually large, making it difficult for an investor or regulator to know whether any loans have been hidden in it. For example, the following table shows the amount of PRM asset and liability on the 2001 balance sheets of Enron and Dynegy.

| Item | Stated Value (Million Dollars) | |
|---|---|---|
| | Enron (Sept. 30, 2001) | Dynegy (Dec. 31, 2001) |
| Assets from Price Risk Management Activities | 14,661 | 6,347 |
| Total Assets | 52,996 | 24,874 |
| PRM Assets as Percent of Total Assets | 28% | 26% |
| Liabilities from Price Risk Management Activities | 13,501 | 5,635 |
| Total Liabilities | 41,720 | 17,396 |
| PRM Liabilities as Percent of Total Liabilities | 32% | 32% |

As an example of the use of PRM to hide debt, it has been widely quoted in the media and in litigation that Enron raised $350 million through a 6-month bank loan from J.P. Morgan Chase (Chase) by structuring it as a series of derivative transactions between Enron, Chase, and an entity owned by Chase known as Mahonia.[78] To make

[77]The Williams Companies, presentation to analysts on December 19, 2001.

[78]"Enron's Many Strands: The Transactions," *New York Times* (February 27, 2002), p. C1.

the loan look like several independent and presumably arms-length derivative deals, Enron and Chase entered into a series of variable-price commodity delivery contracts, which transferred a certain payment amount from Enron to Mahonia, then from Mahonia to Chase, and finally from Chase back to Enron. In other words, the variable payment obligations were merely canceled out, leaving only the fixed payment of $350 million from Chase to Enron, and a fixed payment of $356 million from Enron to Chase after 6 months. In another reported transaction, Dynegy raised $300 million through a loan from Citigroup, using a similarly structured financing deal called Project Alpha.[79]

Since the Enron debacle, the SEC, the FERC, and debt-service agencies such as Moody's have required energy traders to disclose information about transactions similar to Project Alpha. As a result, it is likely that the potential for abuse of derivatives to hide loans will be considerably reduced in the future.

## Transparency of Market Information

The applications of derivatives to risk management are limited by the availability of spot market data—specifically, timely, public, and accurate information on prices and quantities. In addition, to judge the creditworthiness of counterparties and the risks managers are taking, their financial statements should be transparent.

Accurate, timely price and quantity data from spot markets are critical for the design and pricing of derivatives that can be used to manage rather than amplify price risk. As mentioned in Chapter 2, settling futures, swaps and option contracts requires an unambiguous price for the underlying commodity. The formulas used to value (price) derivatives themselves are based on an idealized description of the underlying physical markets. From time to time, the differences between the theoretical and actual commodity markets are significant. For example, commodities sometimes cannot be sold or can only be sold at prices substantially different from the last reported market price.[80] Sometimes market prices are manipulated.[81]

Of more practical concern, in order to value energy price derivatives, analysts must evaluate long time series of historical and current energy prices.[82] In the best of circumstances, forecasting future energy prices is difficult. Without long series of reliable data, forecasting and estimation amount to a leap of faith. And modeling prices with inadequate data and estimation of value can itself introduce as much risk as does the market.

As shown in Chapters 3 and 4, the price and quantity data available for natural gas and electricity markets are of decidedly mixed quality. Published prices from different sources are not always the same. Volume data specific to individual spot markets generally are not available. That would not be a problem for an idealized competitive market where all the participants are small relative to the overall size of the market. In real markets, traders need market volume statistics both to assess the depth of a market and to judge whether their trades might affect market prices.[83]

In the natural gas industry there are a number of firms that more or less informally poll natural gas traders to arrive at various prices. Depending on the source, the published prices may reflect binding bids, offers, actual trades, or starting points for negotiation. Whatever they are, they do not represent the results of a verifiable process.[84] The reporting of energy prices and trade volumes is erratic, informal, and often far after the fact. Prices are reported by interested parties, and in general no one knows the actual prices and volumes traded.

Electricity prices published by the Independent System Operators (California, PJM, New York, and New England) do accurately report binding, market-clearing day-ahead and real-time prices for electricity and some supporting services. Outside those areas, reporting is idiosyncratic. Even the FERC and the Department of Energy have been forced to resort to secondary sources for high-frequency, market-specific data on electricity prices.[85]

The question of whether domestic energy (commodity) markets are sufficiently transparent, liquid, and competitive to support most beneficial uses of derivative

[79]"Number Crunching: Enron Rival Used Complex Accounting To Burnish Its Profile," *Wall Street Journal* (April 3, 2002), p. A1.

[80]Even relatively small traders found that they could not buy and sell at the posted prices on the New York Stock Exchange during the October 19, 1997, meltdown. See, for example, J. Hull, *Options, Futures and Other Derivatives*, 4th Edition (New York, NY: Prentice Hall, 2000).

[81]Federal Energy Regulatory Commission (FERC) Staff Report, *Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-000 (Washington, DC, August 2002), and FERC, "Commission Takes Enforcement Action Against Six Companies," News Release (Washington, DC, August 13, 2002).

[82]See, for example, E. Deman, The Principles and Practice of Verifying Derivatives Prices (New York, NY: Goldman, Sachs & Company, April 2001).

[83]Derivative pricing models assume that the underlying commodity can be bought or sold at the market price. That is to say, the pricing models contemplate relatively small trades.

[84]See FERC's investigation of methods used by various spot market data reporters, Docket number PA-02-2000, Investigation of Potential Manipulation of Electric and Natural Gas Prices, August 2002.

[85]See, for example, "Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998" (September 22, 1998), pp. 5-3 and 5-4.

instruments is unsettled. The inconclusive evidence that is available suggests that location dependence tends to make energy markets smaller, less liquid, and more subject to manipulation than they otherwise would be.[86] The extent to which the use of derivatives is limited by these problems is not known; however, the necessity for valuing derivative contracts on the basis of market data suggests that they constitute a significant barrier. Timely, accurate market data could only encourage the wider use of derivatives to manage local energy price risks.

## Electricity Spot Markets

Until electricity spot markets are working well and providing electricity reliably at competitive prices (near marginal cost), prospects for growth in the market for price-based derivatives are limited. Weather derivatives, outage insurance contracts, and similar risk management instruments are likely to fill the breach partially until such time as electricity markets stabilize.

Recent academic and business literature reflects a growing consensus on what will have to happen in order for electricity markets to become better behaved.[87] Three fundamental elements of that consensus are:

- Some portion of demand must be exposed to real-time prices.
- Transmission must be open, and its cost must be based on congestion charges and any physical marginal costs.
- Rules must be standardized over large areas.

As mentioned in Chapter 4, one cause of extremely high electricity prices is that consumers do not see the actual cost of their use. As a consequence, they continue consuming while the supply system is under stress. Academic economists and many engineers now argue that exposing as little as 10 percent of demand—generally, industry and large commercial users—would decisively reduce price spikes. Price-responsive demand would also be a countervailing force to the exercise of market power.

The U.S. electricity grid was not built to support competition, and transmission service has not been priced to reflect the actual costs of using the system. There is general agreement that substantial investments will be required to increase the capability of the grid to support competition.[88]

What is currently lacking is a market indication of which investments are worth the cost. Generally, in the present situation, transmission charges are set without regard to current congestion and do not reflect actual wear and tear on the grid. When lines are congested, users are cut back according to their priority, and the priorities do not reflect the relative values of canceled and permitted transactions. Economists argue for charges that vary to reflect the real-time congestion that individual generation and consumption decisions impose on the grid.

If transmissions charges reflected actual costs, the usage data could be a reliable indicator of the value of particular transmission lines to users. Heavy usage in the presence of high transmission charges would indicate demand for more capability. Given that information, planners would have a market-based reason for investing in particular grid expansions. At present, however, the rules for market participants depend almost entirely on their location. This balkanization of market rules is a source of complexity that increases the cost of participating in the markets. The FERC's Regional Transmission Organization (RTO) and Standard Market Design (SMD) initiatives, if successful, are likely to reduce both complexity and costs significantly.[89] They do not however directly address the need for price responsive demand.

Even with the development of a generally competitive market, using derivatives to manage electricity price risk will remain difficult. The simple pricing models used to value derivatives in other energy industries do not work in electricity. Barring transmission that is unlimited and free, some participants will be able to manipulate prices in some markets some of the time. These considerations suggest that innovative derivatives, based on something other than spot prices, will be important for the foreseeable future.

## Conclusion

The development of energy derivative markets is strongly influenced by the transparency of financial and

[86]Energy markets are inherently local: natural gas in western Pennsylvania cannot readily be transformed at a known, stable price into natural gas in Philadelphia. For example, correlations between changes in natural gas prices in separated markets are on the order of 0.3, reflecting the high variability of transportation (transmission) costs.

[87]For current examples, see S. Hunt, *Making Competition Work in Electricity* (New York, NY: John Wiley & Sons, 2002); T. Brennan, K.L. Palmer, and S.A. Martinez, *Alternating Currents* (Washington, DC, Resources for the Future, 2002); and 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.

[88]See U.S. Department of Energy, Office of the Secretary of Energy, *National Transmission Grid Study* (Washington, DC, May 2002).

[89]See Federal Energy Regulatory Commission, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000); and *Notice of Proposed Rulemaking: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000 (July 31, 2002).

spot market data. The development of the electricity derivative market is especially dependent on the success of restructuring. None of these problems can be solved solely by private initiative. Whether and how associations (both trade and consumer) and governments will address these issues is an open question that is unlikely to be answered soon.