ECONOMISTS INCORPORATED

*A brief analysis of policy and litigation*

# ECONOMISTS INK

Fall 1995

## USING OPTION PRICING MODELS TO MEASURE DAMAGES IN TRADE ALLOCATION CASES

It is not unusual, nor is it illegal, for securities and commodities professionals to trade the same security or commodity for several accounts during the course of a normal business day. This practice, however, presents the professional with the opportunity to favor some accounts, including his own, over others by allocating the more profitable trades to the favored accounts. For this reason federal securities law and commodities law prohibit brokers, advisers and other market professionals, except in limited instances, from allocating trades after execution. An important issue in litigation on those occasions when the professional abuses his discretion and allocates "good" trades to favored accounts and "bad" trades to another set of accounts is the measure of damages. One measure is the profit earned by the favored accounts as a result of the allocations. Another measure is the loss incurred by the other accounts. In either case, the point in time at which to measure the profits or losses may present a problem. A superior approach, which avoids this problem, is to use an option pricing model.

A simplistic approach to estimating damages is to measure the increase or decrease in the stock price between the time the trade was executed and the time of the allocation. Suppose a professional enters an order to sell a stock with the intention of allocating it to a favored account if the price goes up before the time of allocation. Suppose further that the price does not change at all. Consequently, the trade is allocated to the non-favored account. There has been no increase or decrease in the price of the stock, so the simplistic approach would find no damages. Yet the professional has stolen something from the non-favored account.

A superior way to measure damages in this situation recognizes that, regardless of what happens after the order is placed, the non-favored account gives up something of value at the moment the professional enters the order without designating the account for which he is trading. By failing to designate the account, the professional reserves for himself the right to make the choice later. That right does not materialize from thin air; it is taken from the non-favored account, the account that will get the trade if it turns out not to be a "good" one. That right is an option, and it can be valued, like any other option.

If, for example, the allocated security is a common stock, the option pricing model requires five inputs in order to estimate an option value: (1) the price of the stock at the time the option is created; (2) the option's exercise price, which will usually be the same as the stock price; (3) the volatility of the stock; (4) the risk-free rate of interest; and (5) the time to option expiration. These inputs are usually readily available or can be estimated. It is then a relatively simple matter to generate a reliable estimate of the option's value.

A major advantage of the option pricing approach is that it produces the same estimate of damages or ill-gotten gain regardless of the actual profits or losses of the trading, because it measures the value of what was stolen at the time of the theft. Unlike other measures of trade allocation damages, the option pricing ap-

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proach does not depend on the outcome of the allocated trades, which may be determined by the trading skill or luck of the wrongdoer. The option pricing approach, therefore, offers a consistent method for systematically measuring damages in trade allocation cases.

*Senior Economist Jeffry Davis was formerly Director of Economic and Policy Research of the Securities and Exchange Commission. A more detailed treatment of this topic by Mr. Davis, William C. Dale and James A. Overdahl appears in the February 1994 issue of* The Business Lawyer.

# ELECTRIC BACK-UP SERVICE, EFFICIENT PRICING AND TYING ARRANGEMENTS

As the electric utility industry moves from regulation to open competition, many utilities are devising more efficient pricing structures. For example, Niagara Mohawk has proposed a tariff rate for back-up service with an access fee that approximates the lost contribution to fixed costs when a customer decides to acquire most of its energy demands through self-generation. Intervenors have claimed that Niagara Mohawk's proposed rate constitutes a tying arrangement. The tariff is not a tie, however, but rather an efficient means of recovering costs.

Tying refers to a business practice in which the seller refuses to sell a product the buyer desires (the tying product) unless the buyer also agrees to purchase another product that the buyer otherwise does not desire on the offered terms (the tied product). The Supreme Court's *Jefferson Parish* decision (1984) establishes three criteria for determining whether tying exists: (1) the alleged tying and tied products must be distinct products; (2) the seller must possess market power in the tying product; and (3) the practice must "force" the buyer to accept the tied product and result in substantial foreclosure of sales of the tied product. All three of these elements are necessary to establish a tying arrangement.

In addressing whether the alleged tying and tied products are distinct, it is important to realize that products are not distinct simply because they are priced or sold differently. The products must be in separate antitrust markets. In the electric utility industry there are typically two distinct products from an antitrust perspective: firm capacity and energy. In the case of alleged tying involving back-up services, firm capacity is the alleged tying product and energy is the alleged tied product.

The second question concerns whether the seller has market power in the tying product. Determining whether a utility has market power in firm capacity for back-up service generally requires information specific to each utility. Among the factors to examine are the delivered costs of different types of fuel in an area, the cost of different types of generation plants, the time to construct plants, the specific demands of different customers and rate structures. This question does not have to be answered in many cases, however, because the absence of a tie can be determined with the third criterion alone.

The third question is whether the alleged tying practice results in foreclosure of sales of the tied product. Foreclosure, in the context of tying, refers to the situation in which the seller of the tying product causes another seller of the tied product to lose sales that would have been made but for the tie. It is necessary that commerce actually be foreclosed to ensure that only anticompetitive practices are condemned. If there is no foreclosure, the seller's actions will not adversely affect the market structure of the allegedly tied product. In many cases, buyers would still buy the allegedly tied product from the tying-product seller even if the seller could not engage in the alleged tying practice. In such circumstances, there is no need for antitrust relief.

Foreclosure is an important issue in analyzing alleged tying in the back-up tariff proposed by Niagara Mohawk. The new service classification essentially provides for a two-part price for back-up service. One part consists of a customer-specific access fee for firm capacity and the other consists of a per-unit fee for the energy taken under the agreement. The access fee is calculated as the charge that the customer would have paid under its prior classification less the marginal cost of producing electricity taken under the prior classification. The per-unit charge for energy is approximately equal to the marginal cost of producing energy.

The tariff is not a tie because it does not force buyers to take energy from Niagara Mohawk and it does not foreclose sales by other energy suppliers. The proposal does not explicitly deny firm capacity to any eligible consumer. It does not condition the sale of firm capacity to any customer on that customer's agreement to purchase any other product or service from Niagara Mohawk. Rather, the proposed tariff specifically makes firm capacity available on a separate basis. The tariff rate also does not provide an unreasonable economic incentive which forecloses energy sales by other suppliers.

To show that the tariff would result in market foreclosure, it is necessary to show that customers would obtain a substantial amount of electric power from sources other than Niagara Mohawk in the absence of the proposed tariff. To determine whether the *tariff* causes foreclosure, it is necessary to ask what tariff Niagara Mohawk would use if the proposed tariff is not implemented. Without the proposed tariff, Niagara Mohawk has the incentive to structure alternative tariffs and prices so that customers purchase power from other suppliers only when Niagara Mohawk's marginal cost of energy is above the cost of energy from alternative suppliers. This is exactly the incentive Niagara Mohawk gives its customers in the proposed tariff. Even if Niagara Mohawk sold electricity in a perfectly competitive market, it would price electric energy so that buyers would purchase from it whenever its marginal cost was below the marginal cost of alternative suppliers. In a competitive market, the buyers would buy electricity at the same times and at prices equal to (or higher than) the proposed energy charges.

In general, electric utilities can structure efficient tariffs to recover costs without creating anticompetitive tying arrangements. Niagara Mohawk's proposed back-up service tariff is an example of just such a tariff.

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## ACCESS REGULATION FOR ELECTRIC TRANSMISSION NETWORKS AND THE EXERCISE OF MARKET POWER

Competition in the electric power industry, and antitrust concerns about market power, have increased dramatically in recent years. Competition has increased because of improvements in transmission, communications, and computing technology; reduced scale and construction time for new generation; excess generating capacity; and partial deregulation of generation. These developments have focused attention on difficulties faced by non-owners in obtaining access to the transmission systems required to deliver power. When utilities that own transmission systems are also sellers of wholesale power, they may have an incentive to restrict the use of their transmission systems by competing sellers. Because of concerns over access, deregulation of generation and bulk power sales has been accompanied by increased regulation and discussions of divestiture of transmission systems. The transmission regulations proposed by the Federal Energy Regulatory Commission (FERC), however, are inadequate to resolve the competitive problems.

Until 1992, FERC had little ability to order utilities to provide transmission service. Nonetheless, beginning in the late 1980s, FERC conditioned mergers and deregulation of bulk power prices on agreements by the applicants to provide transmission access. In 1995, FERC proposed its "Mega NOPR" rules that, in principle, require investor-owned utilities to provide access to and information about their transmission systems to enable others to use their transmission systems on the same terms enjoyed by the utilities themselves.

FERC has indicated that it believes that the proposed rules will eliminate the ability of utilities to use their ownership and control over transmission for anticompetitive ends. Since 1992, FERC has refused to investigate competitive effects of some electric utility mergers on the grounds that, if the merging parties agree to supply "open access" transmission, ownership and control of transmission cannot be used to exercise market power. The Department of Justice and the Federal Trade Commission have disagreed with FERC about the effectiveness of regulation and have shown an interest in investigating utility mergers.

FERC's reliance on access regulation assumes that the amount of transmission capacity (more correctly, transfer capability) available for use by third parties is not subject to manipulation by utilities. Transfer capability in a given corridor, however, is not a fixed quantity, even in the short run. Transfer capability is a complex characteristic of an interconnected network. At best, it is estimated for interfaces between areas, not for paths consisting of individual transmission lines. Transfer capability across an interface may be limited by problems on facilities located a significant distance from the nominal interface itself. Furthermore, transfer capability cannot be measured merely by analyzing hardware—transmission lines, transformers, phase angle regulators, capacitors and the like.

The complexity of transfer capability is evident in the simultaneous use of interconnected transmission networks for many different intra- and inter-utility transfers. The network's capability to transfer power from Indiana to Alabama, for example, depends on how utilities in Kentucky and other states use the network to deliver power from their generators to their customers. As a result, Indiana-Alabama transfer capability changes when there are changes in the geographic patterns of generation or consumption of energy in Kentucky and other states.

Indiana-Alabama transfer capability is also affected by power sales between utilities in other states. Power sold by one utility to another flows over all transmission lines connecting these two utilities, including lines on indirect routes. Thus, when utilities in Missouri sell power to utilities in Georgia, some of the power—known as loop flow—actually flows through Indiana. Consequently, transfer capability from Indiana to Alabama changes when additional power is being sold by utilities in Missouri to utilities in Georgia.

Furthermore, changing the way generating plants and the transmission system are operated often changes transfer capability between two regions. For example, suppose that transfer capability from Arizona to northern California was constrained by overloading of transmission facilities in southern California. In that case, a utility in southern California might be able to relax the constraint on transfers from Arizona to northern California by changing the geographic pattern of the generators used to supply its local customers. The southern California utility might be able to increase transfer capability further by disconnecting a low voltage transmission line that overloads before higher voltage lines. While such operating changes may increase generating costs within southern California, that might be more than offset by savings that would result from using low-cost generating plants in Arizona to serve customers in northern California.

Moreover, transmission constraints often do not take the form of fixed limits on the total flows of energy through various pieces of transmission equipment. When transmission facilities are heavily used for long-distance transfers, voltages at various locations in the transmission network may drop. Transfers are then limited by the risk of a voltage collapse and blackout. Such voltage drops can be relieved by appropriate operation of generating plants (to supply what is known as reactive power) near the pertinent transmission facilities.

Because of the nature of the interconnected transmission network, regulation by FERC under the Mega NOPR rules will not prevent utilities from using control over transmission—which may stem from ownership of transmission or generation facilities—to exercise market power. A utility may limit the availability of transmission service to competitors in numerous ways. It may decide to change (or not change) the load levels of its generators, to leave a low voltage line connected, or to limit supplies of reactive power in order to limit the amount of transmission capacity available to competitors. It may also delay repairing or expanding transmission facilities, prolong maintenance outages, or schedule maintenance outages during critical periods. In addition, it may engage in power sales that create loop flows that foreclose transmission service in another corridor.

The ability of utilities to manipulate the availability of transmission capacity for use by competitors potentially threatens competition in delivered wholesale power. FERC's proposed rules are simply inadequate to prevent harm to competition. Analyses of market power relating to bulk power should therefore consider ownership and control over transmission.

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