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REGULATING ELECTRIC UTILITIES WITH SUBSIDIARIES

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EXECUTIVE SUMMARY

The objectives of this report are (1) to develop current information on the various state regulatory treatments of electric utilities with subsidiaries, (2) to analyze the appropriateness and effectiveness of these treatments, and (3) to suggest how these treatments might be improved. The authors surveyed the staffs of commissions in forty-nine states (excluding Nebraska) plus the District of Columbia to gather information on the procedures that commissions use to regulate the relationships between electric utilities and their subsidiaries. The staffs of forty commissions responded.

Electric utilities are setting up subsidiaries in increasing numbers. There is, therefore, special concern about state commission authority to regulate (approve or disapprove) the establishment of subsidiaries by electric utilities. Additional concerns are about whether state commissions can prevent a misallocation of common costs and inappropriate prices in transactions between the utility and its affiliates.

Twenty-seven commission staffs said that their commissions do not have the authority to disapprove the establishment of subsidiaries by electric utilities; ten said that they have such authority; two were uncertain. Most state commissions have not formally evaluated whether the stated or theoretical benefits of establishing a subsidiary have been realized. Only a few commissions periodically reassess the continued appropriateness of a subsidiary. Only three commissions report having authority to order divestiture of an electric utility subsidiary, once established. However, nearly all commissions have procedures to prevent cross-subsidies that could result from a utility-subsidiary relationship. These procedures are most often exercised during rate cases.

An iron-clad source of commission authority over the establishment and divestiture of subsidiaries would, of course, be explicit statutory provisions. Few states have such provisions. While most state commissions do not have explicit statutory authority to disapprove the establishment or divestiture of subsidiaries by electric utilities, there may be sources of authority available to commissions that are implicit in more general statutory provisions. These provisions include those that empower the commission to protect the public interest and to assure that ratepayers are provided adequate service at just and reasonable rates. State commissions might also have an implicit authority to order the divestiture of a subsidiary if the continued existence of the entity would harm the utility or its ratepayers. Many state commissions have a limited or indirect authority to disapprove the establishment of an electric utility subsidiary through their statutory authority to approve or disapprove mergers or consolidations, and the issuance of stocks, bonds, and debentures. A few commissions also have the right to participate as a party in corporate reorganizations.

Not surprisingly, the best time to set up appropriate safeguards to protect the ratepayers from harm is when the entity is established. If a commission asserts authority over a subsidiary's establishment, it can place conditions on its approval.

Concerning the safeguards that are used to protect the ratepayers from abuses of utility-subsidiary relationships, thirty of the forty respondents said that their commissions review the business relationships between an electric utility and its subsidiaries on a periodic basis, most commonly during some phase of a rate case proceeding. To prevent cross-subsidies, nearly all commissions have procedures for examining the joint and other operating costs of an electric utility and its subsidiaries.

Four methods for monitoring diversified electric utilities are available. They are corporate restructuring, audits, affiliated interest statutes, and accounting and recordkeeping procedures. Commissions typically use more than one of these methods to monitor cost transfers between a utility and its subsidiary. Monitoring diversified electric utilities can be facilitated by encouraging restructuring of the utility, that is, by encouraging the formation of holding companies and the spinning-off of nonutility activities into separate subsidiaries. The primary benefit of such a legal separation would be separate accounting and bookkeeping that would facilitate cost tracking and auditing. The commission would still need to satisfy itself that the corporate entities are indeed separate, i.e., maintaining separate facilities, management, and staffs. Further, the commission might wish to predicate its approval of such a reorganization on assurances that it can have access to the subsidiary's books, records, and corporate officers. It should be noted that nearly all commissions report having authority to gain access to the books and records of electric utility subsidiaries, affiliates, and holding companies.

Many of the audits now performed by commissions are comprehensive management audits, but a commission may wish to consider the relative advantages of audits with a narrower focus. A commission may find that a fuel procurement practices audit, an executive management audit, or an affiliate transaction audit is more cost effective. Also, a reconnaissance audit that allows a commission to identify those aspects of a utility's operations in need of further study may be useful.

About half the state commissions have affiliated-interest statutes that allow them to identify and to control any cross-subsidies that flow from affiliate transactions. Two catgories of these statutes exist: those that require a filing that reports the existence of affiliate transactions and those that require that a contract for an affiliate transaction be approved by the commission beforehand. Affiliated-interest filing requirements are a logical, cost-effective first choice for monitoring affiliate transactions. An affiliated-interest contract preapproval statute, however, might be the only method available that will completely assure that the costs of imprudent affiliate transactions do not end up in the utility's rates.

Most commissions require the utility to keep its books in accordance with a Uniform System of Accounts (U.S.O.A.) and to separate the costs of a subsidiary from its parent utility. The U.S.O.A. has several limitations. For example, the U.S.O.A. does not require the maintenance of cost data on a functional cost center basis; hence, cost allocation methods may be less precise than they would otherwise be due to a lack of information. Also, with the U.S.O.A.'s aggregation of accounts relating to transactions with affiliated companies, acquiring useful information for regulating these transactions can be both costly and time consuming. There are three possible solutions. One would be to require the use of a separate clearing account for all transactions with affiliates. By thus centralizing in one location all information pertaining to affiliate transactions, auditing and tracing of costs would be facilitated. Another solution would be to require utilities to journalize all affiliate transactions into a single monthly entry, thus reducing the time necessary for an audit. Finally, commissions might require the filing of supplemental schedules pertaining to affiliate transactions. Such schedules could provide useful summary information for subsequent in-depth review or desk audits of the utility's books.

A particularly difficult common cost allocation problem faced by commissions is to distinguish an operating utility's cost of capital from that of its subsidiaries. When an electric utility has subsidiaries or is itself owned by a parent company, its capital is likely to be intermingled with the capital of the other entities. This is because a single entity, either the parent utility or the holding company, issues all equity for which an observable market exists. Hence, the observable market return on equity reflects some mix of returns for the various corporate entities.

Two methods generally used for estimating the cost of equity in such circumstance are (1) comparisons with similar, regulated companies, and (2) some variation of a double leverage method. Where possible, the comparison approach is preferred. In the absence of information about the equity costs for some of the subsidiary entities, the double leverage techniques do not work. All double leverage methods necessarily estimate the weighted average cost of capital of a subsidiary as some sort of unlevered average of the parent company's overall return. This average is sometimes further adjusted for the specific, relative leverage of the individual subsidiaries. No double leverage technique, however, can account for the relative operating riskness of a parent's subsidiaries. None can provide a way of unraveling the parent's amalgamated return, which is observed in the market, into its component parts. Thus, none provides a good estimate of a subsidiary's equity cost until independent market information is used to identify a subsidiary's operating risk.

Where utilities purchase goods or services from subsidiaries, most commissions try to prevent pricing abuses by one of three approaches. Under the market-price approach, the subsidiary's prices are deemed reasonable if they are less than or equal to those charged by nonaffiliated suppliers of the same goods or services. Under the profit-comparison approach, the subsidiary's prices are considered reasonable if the return on capital of the subsidiary does not exceed that earned by other, nonaffiliated suppliers of the same goods or services. The cost-plus-the-utility's-rate-of-return approach limits the subsidiary to earning the sum of its costs plus a return on capital based on the rate of return that the regulated public utility is allowed.

The market-price approach is the best from an economic point of view, since the market price (1) reflects the relative scarcity or opportunity cost of the goods in question, (2) encourages efficiency of production by captive and noncaptive subsidiaries, and (3) encourages the efficient allocation of the utility's financial reserves. But, the market-price approach is not without problems. One of the practical drawbacks is that it presumes the existence of a competitive market for the goods being transferred. Such a market may not exist if the subsidiary exercises sufficient market power to influence price. Also, two key assumptions underlie this approach. One is that the utility's investment in the subsidiary is financed entirely out of the utility's retained earnings and not from any contributions, explicit or implicit, from the ratepayers. The other is that there is no cross-subsidization of the subsidiary by the utility in its day-to-day operations. If either of these assumptions is violated, then the market-price approach may not be preferred. One last hurdle exists for a commission using the market-price approach: the commission must be able to identify the proper market in order to compute comparable market prices. This task may, in some instances, be extremely difficult, which suggests that use of the alternative approaches might be reasonable.

The profit-comparison approach is based on the assumption that if a subsidiary's profits are higher than those of other firms in its industry, these profits are the result of either synergistic benefits from the utility-subsidiary relationship or from some kind of implicit subsidization of the subsidiary by the utility. If either of these assumptions were true, then under this approach ratepayers would be allowed to benefit from this synergism or the cross-subsidy would be eliminated from rates. Assuming the subsidiary is competitive with other firms in its industry, the profit comparison approach would pass on to the ratepayers the profits resulting from the synergism or cross-subsidy. A difficulty with this approach is that this key assumption may often be invalid. Under the profit-comparison approach, the ratepayers would bear the risk of a subsidairy's inefficiency should the subsidiary prove uncompetitive. On the other hand, if the utility's subsidiary is more efficient than the market, the source of its "excessive" rate of return could be superior resources, management, or other factors. As long as the utility's investment in the subsidiary comes solely out of the utility's retained earnings, one might expect the excess profits to go to the shareholders. The profit-comparison approach awards these profits to ratepayers in the form of lower rates.

While the profit-comparison approach sets the subsidiary's rate of return equal to that of similar unregulated firms, the utility-rate-of-return approach sets it equal to that of the regulated parent. The utility-rate-of-return approach is based on the premise that the utility's subsidiary is *de facto* a part of the public utility and should be regulated as such for purposes of determining reasonable rates of return on invested capital. This approach might best be limited to circumstances where the subsidiary in fact operates as an extension of the utility. This would be the case where the subsidiary exercises market power sufficient to influence the price of the goods in question, particularly if its market power stems from the utility-subsidiary relationship. However, in choosing among these three methods, a commission needs to be concerned that the utility not be discouraged from making economically efficient investments in related or vertically-integrated activities where synergisms can be achieved.

TABLE OF CONTENTS

TABLE OF CONTENTS--Continued

FOREWORD

In recent years the issue of regulating electric utilities with subsidiaries has received a good bit of practitioner and academic attention. Now with a few years of experience under various regulatory arrangements and treatments, this report presents the current status of the matter, e.g., authorities among the other states to approve or disapprove their formation, safeguards and monitorship imposed, and the major approaches employed.

Many of the results draw upon responses from the staff of the forty state public utility commissions that provided data and information for the study.

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CHAPTER 1

INTRODUCTION

Objectives

In recent years, electric utility managements have shown a growing interest in diversification through the establishment of subsidiaries and holding companies exempt from the requirements of the Public Utility Holding Company Act. The establishment of utility subsidiaries and exempt holding companies raises a variety of issues and concerns for state regulators. Much has been written about the subject. The objectives of this particular study are (1) to provide state public utility commissions with information about the various regulatory treatments, regarding electric utility subsidiaries and affiliated companies, that state commissions use, (2) to analyze the economic appropriateness and the effectiveness of the various regulatory treatments, and (3) to suggest how these treatments might be improved.

The report, in turn, is organized around three sets of issues. The _first_ set of issues concerns the traditionally argued economic advantages and disadvantages of electric utility subsidiaries, i.e., what are the theoretical pros and cons of allowing an electric utility to establish a subsidiary.

The _second_ set of issues regards state commission authority over the establishment and operation of electric utility subsidiaries. In other words, to what extent do commissions have the authority to prevent the economic abuses that may be inherent in electric utility subsidiaries? Specifically, the set of issues concern whether commissions can allow or disallow the establishment of electric utility subsidiaries or affiliates, whether a commission can attach conditions to its approval of the establishment of the subsidiary or affiliate, whether a commission can require a utility to divest itself of its subsidiary, whether state commissions directly regulate electric utility subsidiaries, and how the transactions between the parent utility company and its subsidiary are handled.

The third set of issues addressed in the report concerns what the appropriate and effective regulatory policies and procedures are for protecting the public interest when subsidiaries exist. This set of issues includes a commission's ability to isolate and control transfer prices and cross-subsidization of costs. Some of the regulatory policies and procedures to be examined include various forms of monitoring such as staff reviews, staff audits, outside audits, and formal commission hearings (both in and outside the rate case setting). Other commission policies and practices to be examined include the development and use of special accounting standards, practices that evaluate transfer prices in the light of market prices, practices relating to the return earned by the subsidiary in transactions with the utility, and practices where the subsidiary is regulated as a public utility. The relative severity and cost of each of these potential commission policies and practices are also examined.

This report mainly covers the simple utility-subsidiary relationship, where the utility is the parent organization. The report is not concerned directly with the interstate holding company arrangements, where a holding company is established to own utility and utility-related affiliates. In the interstate holding company system, it is the utility which is the subsidiary. Indeed, several existing interstate holding companies own several utilities each as their subsidiaries together with other subsidiaries that are "reasonably incidental" or "economically necessary" to the business of operating an integrated utility system. These are the registered holding companies that are regulated by the U.S. Securities and Exchange Commission (SEC). These structures are not the subject of our report. However, much of the history of utility-subsidiary arrangements flows out of the abuses that occurred during the period of holding company dominance before the Public Utility Holding Company Act of 1935 was enacted. Also, much of the literature deals with the interstate holding company structure. Therefore, the authors found it to be impractical to attempt to discuss the utility-subsidiary relationship without looking to the literature on holding companies.

The authors also discuss to some extent those holding companies that are exempt from the Public Utility Holding Company Act pursuant to sections 3(a)(1) and 3(a)(2) of the Act.[1] These provisions grant an exemption to certain holding companies from regulation by the Securities and Exchange Commission. Section 3(a)(1) exempts any holding company if it and its subsidiary utilities are organized in a single state and the utility operations are confined substantially within the state. (There could be some insubstantial degree of out-of-state utility operations.) These are the so-called intrastate holding companies. An intrastate holding company can have nonutility subsidiaries that are located out-of-state or are engaged in out-of-state nonutility activities.

Section 3(a)(2) of the Public Utility Holding Company Act provides an exemption for a holding company that is itself primarily a utility that operates in the state in which it is organized and the adjoining states. This type of holding company can have nonutility subsidiaries that operate in states other than the state of organization and the adjoining states. For a holding company to be granted this exemption, it must have utility revenues that predominate in terms of the gross utility revenues and assets of the holding company. This type of holding company comes under the jurisdiction of a state commission because the holding company is itself a

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[1]The Public Utility Holding Company Act of 1935, 15 U.S.C. §79-z-6. It is worth noting that there are three other exemptions available from the Public Utility Holding Company Act of 1935. Section 3 (a)(3) of the Act provides the "only incidentally a holding company" exemption for holding companies in which the utility business is functionally-related (incidental) to a nonutility business and where only small amounts of income are derived from the utility subsidiary. Section 3 (a)(4) provides for the "temporary holding company" exemption that deals with bankruptcies, reorganizations and defaults where an investor only temporarily holds the company. Section 3(a)(5) provides one other exemption: holding companies over foreign utilities. The section 3(a) exemptions are subject to one very important clause, commonly called the "unless and except" clause. This clause provides the SEC with the power to withhold, revoke, or condition exemptions "insofar as [the SEC] finds the exemption detrimental to the public interest or the interest of investors or consumers." See generally Douglas W. Hawes, Utility Holding Companies (New York: Clark Boardman Company, Ltd., 1985), at §3.04.

regulated utility. A state commission could exercise its authority if such a holding company sought to establish nonutility subsidiaries.

The reason that these so-called exempt holding companies are to some extent within the scope of this report is that they are not subject to SEC regulation. The section 3(a)(2) holding companies are subject to state commission regulation. The section 3(a)(1) so-called intrastate holding companies could be more troublesome for state commissions because their nonutility subsidiaries can be interstate, and hence possibly exempt from state commission regulation (due to the Commerce Clause).

This report does not address the desirability or undesirability of repealing or amending the Public Utility Holding Company Act of 1935. For the purposes of this report, the PUHCA in its current form is treated as a given. Throughout this report the term "subsidiaries" will be used to mean both subsidiaries and affiliates unless a distinction is necessary.

Occasion

The interest in diversification by electric utility managements can be traced, in part, to the recent financial strength of a majority of electric utility companies. While a minority of electric utilities are strapped financially, most electric utility companies are financially strong. Most electric utilities have benefitted from reduced capital expenditures due to a winding down of their construction programs.

Because of their improved financial condition, many electric utility companies find themselves with a surplus of internally generated funds. Such companies are typically called "cash cows." Such a surplus of funds will force utility managers to choose between (1) raising the dividend payout ratio for the utility's common stock; (2) retiring, redeeming, or voiding high coupon debt and preferred stock; (3) repurchasing the utility's outstanding common stock; (4) initiating construction of generating plant to meet the anticipated demand of the 1990s; (5) establishing subsidiaries or affiliates to diversify into utility-related projects; (6) establishing subsidiaries or affiliates to diversify into nonutility related projects; and (7) investing in the financial assets of other companies.[2]

For various reasons, some of these alternatives may be unattractive to electric utilities. If, for example, utility managers raise the dividend payout ratio for a utility's common stock, the price of the stock is likely to rise. Should the price of common stock rise to levels where its market-to-book price ratio greatly exceeds 1.0, utility executives worry that regulators may take that as a signal that the utility's return on equity is too high. The regulators may then order a lower return on equity in future rate cases. Similarly, should a utility management choose to retire, redeem, or void the high coupon debt or preferred stock or repurchase common stock, the utility's capital structure would change. The utility would have a higher equity-to-debt ratio.[3] In such a situation, utility managers worry that regulators are likely to recognize that the before-tax cost of equity is higher than the cost of debt. Furthermore, equity is much more expensive than debt because dividends are taxable to the utility while debt interest costs are deductible. When faced with a radical change in capitalization, state regulators have sometimes imputed a hypothetical capital structure in order to protect ratepayers from excessive capital charges. Similarly, other state commissions have determined what the optimal capital structure of the utility must be in order to minimize long-run capital costs. Because utility managers may face the ultimate prospect of a lower allowed return on equity if they increase their utility's equity-

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[2]These options were suggested by four sources: Charles M. Studness, "Electric Utility Investment in Nonutility Assets," Public Utilities Fortnightly, September 1, 1983, pp. 46-47; Phillip S. Cross, "'Equity Thickening' - How Will Regulators Respond? " Public Utilities Fortnightly, September 5, 1985, pp. 54-56; and Paul G. Russell et al., "American Bar Association Section of the Public Utility Law, Report of the Utility Financing Committee: Utility Financing During the First Nine Months of 1984" (Mimeographed, October 1984), pp. 4-9, 14-16; and Laura J. Rittenhouse, "The Brave New World of Debt Financing," paper presented to the ABA, Section of Public Utility Law, September 17, 1984, pp. 7-8.

[3]However, such would not necessarily be the case if the utility's treasury stock are excluded from rate base. (The utility's earnings per outstanding share of common would still rise, perhaps leading regulators to cut rates so that the utility does not exceed its allowed rate of return.)

to-debt ratio, the option of retirement, redemption, or defeasance of high cost debt or repurchasing equity may appear unattractive.

Most utility managers are also somewhat less than eager to use their excess cash to begin the next construction cycle. Utility managers have recently experienced declining growth rates which caused many of them to cancel generating plants under construction. In addition, the managers of utilities that did complete construction of their plants often faced prudence inquiries into construction cost overruns, rate of return penalties, exclusion of plant from rate base or gradual phase-in of plant into rate base, because of overbuilding or potential "rate shock". These regulatory policies, while possibly appropriate for dealing with the immediate problem at hand, may have the unintended consequence of making utility managers "gun-shy" about building new generating plant.

Thus, utility managers are more likely to have found the remaining options more attractive. If a utility has not already diversified into available utility-related ventures, management might find such a move to be particularly worthwhile. As noted in the next chapter, diversification into vertically integrated utility functions, such as coal mining and fuel transportation, can lead to desirable synergies that can lower a utility's overall costs. Diversification into nonutility related ventures can also be an attractive option for utility managers if investment in such ventures promises a rate of return higher than can be earned by reinvesting in the utility itself. The third of these remaining options, investing in the financial assets of other companies, can be a means for a utility to diversify without having the headaches that go along with managing a company engaged in types of ventures with which the utility management has little experience.

As a result of these considerations, many utility managers with excess cash have decided to diversify their utilities by setting up utility subsidiaries or affiliates and sometimes exempt holding companies.

Some utilities have set up subsidiaries that are clearly utility-related. Several utilities, for example, have set up subsidiaries to finance, develop, or operate cogeneration and small power facilities. These utilities include Central & South West Company, Alabama Power Company, the Allegheny Power System, Texas-New Mexico Power Company, CP National Corp., Iowa Electric Light & Power Company, Central Hudson Gas & Electric Company, Niagara Mohawk Power Company, Utah Power & Light Inc., Middle South Utilities, Inc., the FPL Group (Florida Power & Light's holding company), the Jersey Central Power & Light Company, and Southern California Edison Company, to name a few. Other utilities, such as the Wisconsin Public Service Company, have applied to set up cogeneration subsidiaries.[4] The Utah Power & Light Company's new subsidiary, Energy National Corporation, was formed to allow the utility to diversify into other energy-related fields, including small hydroelectric projects.[5] Two other examples of electric utilities setting up subsidiaries that are utility-related concern fuel transportation. The New England Electric System Company, a registered holding company, was granted a "special or unusual circumstance" exemption from cost-plus based pricing under the PUHCA section 13(b) for its new coal transportation joint venture. The SEC exemption allows the new joint venture to charge a rate based on market prices, instead of the cost plus a reasonable profit.[6] A more recent example is the TECO Transport & Trade Corporation which delivers coal by barge to the Tampa Electric Company. Both TECO Transport & Trade Corporation and Tampa Electric Company are subsidiaries of the TECO Energy Inc. holding company.[7]

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[4]"Most Utility Congeneration Investment Units Have Yet to Begin Projects," Electric Utility Week, February 11, 1985, pp. 11-12; "Jersey Central P&L Gets SEC Approval to Set Up Cogeneration Subsidiary," Electric Utility Week, March 4, 1985, pp. 9-10; "Florida P&L Parent Forms Subsidiary to Develop Cogeneration Projects," Electric Utility Week, August 5, 1985, p. 14.

[5]"Utah Power & Light Moves to Create Cogeneration and Small Power Subsidiary" Electric Utility Week, July 9, 1984, pp. 10-11; "Utah Power & Light's New Energy Subsidiary to Take On Small Hydro Development," Electric Utility Week, October 1, 1984, pp. 11-12.

[6]"New England Electric Gets Holding Company Act Exemption for Coal Ship," Electrical Week, December 21, 1981, p. 1.

[7]"Tampa Electric Shaves Coal-Haul Costs $25 Million Yearly with Barging," Electric Utility Week, September 17, 1984, pp. 11-12.

Many other subsidiaries have been established recently to enter into ventures that are only somewhat, if at all, utility-related. Sometimes, these subsidiaries sell to others services initially developed for a utility's use. Other times, these subsidiaries are only remotely related to the utility and its activities. It is within these two broad classes of non-utility related ventures that most of the recently established subsidiaries fall.

Several electric utilities, for example, are diversifying into the telecommunications industry. The Iowa Electric Light and Power Company, for example, has recently invested in the Teleconnect Company by purchasing 26 percent of Teleconnect's common stock. The Teleconnect Company is engaged in a tele-marketing equipment venture.[8] Several utilities have become involved in the establishment of fiber optic networks. The Public Service Electric and Gas Company (PSE&G), for example, granted permission to Light Net, a telecommunications company that is a joint venture of Southern New England Telephone Company and CSX Corporation, to use certain of PSE&G's rights-of-way in exchange for usage and ownership rights to part of the Light Net Company system. (PSE&G plans to use the system solely for its own data communications.) SCANA Corporation, the holding company formed by South Carolina Electric & Gas Company, plans to build a fiber optics link for its own use. Similarly, Rochester Gas & Electric Corporation and Arkansas Power & Light Company have also built fiber optics networks for their own internal use.[9]

Other electric utilities have entered the telecommunications field and have not limited themselves to activities for their own use. For example, Ipalco Enterprises, the holding company of Indianapolis Power & Light Company, reached an agreement in principle to acquire a cable television business.[10] The Montana Power Company set up a subsidiary to develop

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[8]"Iowa Utility Invests in Telemarketing Firm," Public Utilities Fortnightly, June 13, 1985, p. 32.

[9]"Report of Financing Committee," ABA Utility Section Newsletter, Vol. 25, No. 4, July 1985, p. 7.

[10]"Indianapolis Power & Light Parent Set to Acquire Cable Television Business," Electric Utility Week, July 9, 1984, p. 10.

software for utility telecommunications applications. The Minnesota Power Company's Topeka Group subsidiary purchased a telecommunications firm, JayEn Inc., that sells and services mobile radios, telephone systems, audio equipment, and close-circuit television. The Wisconsin Power & Light Company has also established a telecommunications subsidiary, Wisconsin Mobile Telephone Inc. The earliest electric utility to get involved in telecommunications is Pacific Power & Light Company, whose Pacific Telecom Co. subsidiary now owns more than thirty ventures engaged in a whole gamut of telecommunication services.[11]

The Southern Company, a registered holding company, was allowed by the SEC to form a new subsidiary. This subsidiary would engage in a joint venture furnishing homeowners with enhanced telecommunications services, such as home banking, electronic shopping, home security, and energy management systems.[12]

The Southern Company also received SEC approval to set up a subsidiary called Southern Electric International Company that now provides technical and engineering consulting to utilities and industries worldwide.[13] The American Electric Power Company, another holding company regulated by the SEC, also set up a similar consulting subsidiary called AEP Energy Services Company.[14]

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[11]"Three Electric Utilities Enter Telecommunications Field; More on Way," Electric Utility Week, May 19, 1984, pp. 5-6.

[12]"Southern Company Entering Home Energy Management and Entertainment Business, " Electric Utility Week, July 9, 1984, pp. 1-2; "Southern Co. Gets Okay for Home Energy Management, Entertainment Business," Electric Utility Week, October 15, 1984, p. 9.

[13]See "Georgia: Diversification Plan Approved," Public Utilities Fortnightly, March 4, 1982, p. 55; "SEC Okays New Diversification Venture--A Southern Co. Engineering Firm," Electrical Week, January 4, 1982, p. 7. "Equipment & Services," Electric Utility Week, October 8, 1984, p. 11.

[14]"AEP Seeks to Diversify into an Outside Engineering-Consulting Business," Electrical Week, February 8, 1982, p. 5; and "AEP Gets Okay to Diversify into a Consulting Business Serving Clients Outside," Electrical Week, May 17, 1982, p. 6.

Other utilities have established subsidiaries that are engaged in other types of activities that are not utility-related. The Orange and Rockland Utilities, for example, have set up an unregulated real estate development subsidiary which will promote commercial and industrial growth in the company's service area by funding joint ventures with developers or with potential new customers.[15] Likewise, the Public Service Company of Colorado has a real estate investment subsidiary, Bannock Center Corporation, which has been very active in redevelopment in Denver, Colorado.[16] The FLP Group Inc., the holding company parent of Florida Power & Light Company has recently purchased a computer supply and business form company.[17]

An extreme example of an electric utility diversifying into nonutility related ventures is the recent case in which Florida Progress Corporation, the holding company whose major subsidiary is Florida Power Company, formed a partnership between its subsidiary, Progress Equity, Inc. and two other entities. The new partnership will attempt to bring a professional baseball franchise to St. Petersburg, Florida. To the extent that this venture is at all related to utility activities, it is because the city of St. Petersburg and Pinellas County, Florida agreed to fund a $60 million, 43,000 seat air-conditioned domed stadium as a prerequisite for obtaining a major league baseball franchise. It is expected that the new stadium would have a load of 4 to 6 MW that would often fall in the Florida Power Company's peak hours, thus aggravating (lowering) the utility's load factor.[18]

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[15]"Unregulated Real Estate Units Approved for O&R; First Ones in N.Y. State," Electric Utility Week, September 17, 1984, p. 7.

[16]"PS Colorado Real Estate Unit Plans $500-Million Redevelopment of Eight Blocks," Electric Utility Week, July 9, 1984, p. 11.

[17]Paul G. Russell et al., p. 10.

[18]Ibid. See also, "Florida Progress Spearheading St. Petersburg's Bid for Baseball Franchise," Electric Utility Week, April 30, 1984, p. 8. This is a rather extreme example.

Another recent trend is the establishment of investment subsidiaries. For example, the Potomac Electric Power Company has a wholly-owned subsidiary called Potomac Capital Investment Corporation. This subsidiary had as of December 31, 1984 an investment portfolio of $262 million, including $113 million in sinking funds and adjustable rate preferred stocks, $77 million in specialized mutual funds, $21 million in moneymarket investments, and the balance in leveraged equipment leases.[19]

The relative size of electric utilities' diversified ventures also appears to be increasing. The nonutility operations of the Duke Power Company accounted for ten percent of its earnings in 1984.[20] The Public Service of New Mexico Company, for example, now receives 14 percent of its corporate earnings from its investment subsidiary alone.[21] Some utilities that have a low expected annual load growth plan to pursue diversification aggressively. The Washington Water Power Company, for example, plans to set up subsidiaries and diversify to the point where nonutility ventures account for 50 percent of the utility's net income. The utility management hopes to reach this goal by 1995. In 1984, the nonutility ventures represented 10.6 percent of the stockholders' earnings per share.[22]

Another discernible trend is that electric utilities are establishing a greater number of exempt holding companies. As noted by Douglas W. Hawes, "the most notable development during the last fifteen years has been the creation of a number of exempt holding companies, mostly one-utility holding companies."[23] Hawes cites the following prominent exempt intra-

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[19]Paul G. Russell et al., pp. 11-12.

[20]"Non-Utility Operations Accounted for 10% of Duke Power Earnings Last Year," Electric Utility Week, February 25, 1985, p. 7.

[21]"PNM Says Diversification Paying Off; 14% of Earnings from Investment Unit, "Electric Utility Week, April 29, 1985, pp. 12-13.

[22]"WWP Wants Diversification to Provide 50% of Income to Shareholders by 1995," Electric Utility Week, March 18, 1985, p. 11.

[23]Hawes, Utility Holding Companies, pp. 2-24 - 2-25.

state holding companies formed under section 3(a)(1) of the Holding Company Act together with their principal electric utility subsidiaries: (1) Dominion Resources, Inc. (Virginia Electric and Power Company), (2) Florida Progress Corporation (Florida Power Corporation), (3) Houston Industries, Inc. (Houston Lighting & Power Company), (4) Iowa Resources, Inc. (Iowa Power and Light Company), (5) TECO Energy, Inc. (Tampa Electric Company), and (6) Texas Utilities Company (Dallas Power & Light Company.[24] All told, as of June 1, 1985, there were almost 120 holding companies exempt under either sections 3(a)(1) or 3(a)(2) of the PUHCA.[25] Recent actions by electric utilities include the Iowa Public Service and South Carolina Electric & Gas companies reorganizing into exempt holding companies in 1984 named Midwest Energy Company and SCANA Corporation, respectively.[26] The Indianapolis Power and Light Company also reorganized its corporate structure and became the exempt holding company IPALCO Enterprises, Inc.[27] Two small New Hampshire electric companies, Concord Electric and Exeter & Hampton Electric Companies, recently formed a holding company called UNITIL Corporation.[28] In Nevada, Sierra Pacific Power Company established an

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[24]Ibid, pp. 2-25 - 2-26.

[25]U.S., Securities and Exchange Commission, Division of Investment Management, Holding Companies Exempt from the Public Utility Holding Company Act of 1935 under Sections 3 (a)(1) and 3 (a)(2) Pursuant to Rule 2 Filings or by Order as of June 1, 1985, pp. 1-10, 13-16.

[26]"Iowa Public Service Completes Reorganization into a Holding Company Structure," Electric Utility Week, May 7, 1984, pp. 10-11; "SCANA Stockholders First in Industry to Okay Measures Thwarting 'Greenmail,'" Electric Utility Week, April 29, 1985, pp. 5-6.

[27]"Indiana: New Corporate Structure Proposed by Utility," Public Utilities Fortnightly, September 29, 1983, p. 57.

[28]"New N.H. Holding Company Eyes Small Power to Replace Supply from P.S.N.H.," Electric Utility Week, April 8, 1985, pp. 9-10.

exempt holding company called Sierra Pacific Resources Company.[29] The Illinois Commerce Commission gave permission to the Central Illinois Light Company to proceed with its plan to form a Holding company and to diversify into nonutility ventures.[30] In California the management of the San Diego Gas and Electric Company recently announced its plans to form a holding company. Formation of a holding company is subject to shareholder and California Public Utilities Commission approval.[31]

A major intrastate exempt utility holding company has been proposed in Ohio to facilitate the merger of the Cleveland Electric Illuminating Company and the Toledo Edison Company.[32] According to Toledo Edison, the merger has been proposed to give the utilities the strength of size to allow them to meet the competitive challenge ahead. The advantages for the participating utilities cited in favor of the merger include a greater combined purchasing strength permitting fuel and other operating cost savings, consolidation of staff, greater stability in industrial sales, improved bulk-power market opportunities, easier integration of new generating technologies, increased efficiency because of coordination of generation and transmission facilities, better access to capital markets and reduced financing costs. W.T. Grimm & Company, a merger consulting firm, observed that the planned merger will be the largest such transaction in the history of the utility industry.[33] The new holding company is expected to have

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[29]"Sierra Pacific Wraps up Restructuring; Consumer Advocate Moves to Unravel It," Electric Utility Week, June 11, 1984, pp. 1-2; "Nevada Consumer Advocate's Challenge of Sierra Pacific Restructuring Fails," Electric Utility Week, July 16, 1984, p. 11.

[30]"Holding Company for Central Illinois Light Approved by Illinois Regulator," Electric Utility Week, January 14, 1985, p. 6.

[31]"California: Utility Plans to Form Holding Company," Public Utilities Fortnightly, June 27, 1985, p. 46.

[32]"Ohio Utilities Fortify for Future, Others May Follow," Electrical World, August 1985, pp. 23-24, 27.

[33]"Planned Merger Will Be Largest Utility Transaction in History," Public Utilities Fortnightly, July 25, 1985, p. 37.

combined assets of more than $8 billion. The planned merger and holding company restructuring is subject to approval by the stockholders, the Public Utilities Commission of Ohio, and the Securities and Exchange Commission.[34] The new holding company will seek an exemption as an intrastate holding company from the PUHCA.

Because of the implicit role that the PUHCA plays in the current trend toward the establishment of subsidiaries and holding companies, we have included a short appendix (appendix A) containing a discussion of the problems and abuses that led up to the enactment of that law for those readers not familiar with that history.

Organization of This Report

The remainder of this report is organized in two parts. The first part (chapters 2 and 3, supplemented by appendices B and C, and the annotated bibliography) fulfills the first objective of the study by providing the reader with information about the various regulatory treatments of electric utilities with subsidiaries and affiliated companies that state commissions use. Chapter 2 contains a literature survey in which the major regulatory issues relating to electric utilities with subsidiaries are identified plus a discussion on comments made by others, concerning these issues. Because many of the experts who have written on the topic disagree, and the available information is either incomplete or not current, the authors conducted a survey about the regulatory treatments of electric utilities with subsidiaries in current use at the state commissions. Chapter 3 reports the results of the survey. Appendix B contains the survey questions and transcripts of the states' responses. Appendix C presents copies of selected commission orders and statutory provisions. These were furnished by the commissions or researched independently by the authors and were selected by the authors because they represented illus-

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[34] "Plan for Major Electric Utility Merger Revealed," Public Utilities Fortnightly, July 11, 1985, p. 39. See also, "Ohio PUC to Question Electric Utility Merger," NARUC Bulletin, No. 32-1985, August 12, 1985, p. 14.

trative examples of commission statutes and orders. The annotated bibliography provides full references to and summaries of the sources used mainly in chapter 2 and in other parts of the report.

The second part of the report (chapters 4, 5, 6, and 7) fullfills the second and third objectives of this study by providing the reader with an analysis of the economic appropriateness and the effectiveness of the various regulatory treatments and by suggesting how these treatments might be improved. Chapter 4 covers the process of defining commission authority. It suggests possible sources of commission authority for regulating electric utilities with subsidiaries. Chapter 5 analyzes the various regulatory methods for identifying and monitoring the joint and common costs of a diversified electric utility. Where appropriate, the authors suggest how these methods might be improved. Chapter 6 covers the problems involved in estimating a utility's cost of capital when the utility has subsidiaries. Chapter 7 analyzes and evaluates the various regulatory treatments that are available to a commission faced with the transfer prices of an affiliate transaction. Some suggestions are made on how these treatments might be improved.

CHAPTER 2

REGULATORY ISSUES RELATING TO ELECTRIC UTILITY SUBSIDIARIES

The main issues relating to the regulation of electric utilities with subsidiaries are set out in this chapter along with a summary of what others have said in the literature about these issues. The first section of this chapter covers issues that have economic aspects, such as transfer pricing, cross-subsidization, and management expertise. The second section of this chapter covers what is known (from the literature) about the authority of state utility commissions in various areas relating to electric utilities with subsidiaries. The third section of the chapter summarizes the regulatory practices and policies reported to be in use by state commissions in their oversight of electric utility subsidiaries. The last section deals with the issue of whether state regulators have sufficient expertise, particularly in nonutility markets, to deal with utility subsidiaries. The material in this chapter is designed to serve as a bridge, fleshing out the points raised in chapter 1 and providing a base for the discussion of the survey results in chapter 3.

Economic Issues

Several major economic issues are discussed in this section. These are the issues of transfer pricing and cross-subsidization as well as the effects of subsidiaries on risk, on the utility's return on equity, on utility fuel costs, on potential synergistic benefits, on utility management expertise, and on technical innovation.

Transfer Pricing

An important issue when dealing with electric utility subsidiaries is the problem of transfer pricing. This problem arises when an electric utility and its subsidiary engage in business transactions with each other. The subsidiary may charge the utility an above-market price for goods and services knowing, that these increased costs to the utility will be passed through to its ratepayers in the form of higher rates.

A study by Christopher J. Rozycki and Richard A. Nelson provides some empirical evidence on the occurrence of transfer pricing. The study reported on a survey of seventy-six electric utilities conducted by Technical Research Analysis Company for the FERC in 1981. The survey dealt with electric utility diversification into fossil fuel production. Forty-nine of the seventy-six utilities responded to the survey.[1]

One of the findings was that at the time of the survey most (60 percent) of the utilities' associated fuel companies were charging the electric utilities higher than average prices for fuel. Twenty percent of the associated companies were charging prices equal to the average and the remaining twenty percent charged below average prices.[2]

Of the associated companies charging higher than average prices, 56 percent charged prices that were greater than 10 percent above the average, 36 percent charged prices that were greater than 20 percent above the average, 16 percent of the associates charged prices that were greater than 30 percent above the average, and 4 percent of the associated companies charged prices that were greater than 40 percent above the average. The authors note that 80 percent of the associates charging above average prices were allowed to pass "extraordinary and regulatory" costs through to the utility. Rozycki and Nelson state that "this data would indicate that ratepayers, on the whole, are paying a premium for utility purchases of associate provided fossil fuels."[3]

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[1]See Christopher J. Rozycki and Richard A. Nelson, "Electric Utility Diversification into Fossil Fuels," in Proceedings of the Third NARUC Biennial Regulatory Information Conference, ed. Daniel Z. Czamanski (Columbus, Ohio: The National Regulatory Research Institute, 1982), pp. 199-214.

[2]Ibid., p. 206.

[3]Ibid., pp. 206-207. The authors state that the average prices are "reflective of non-associate fuel deliveries, excluding associate deliveries."

The problems of transfer pricing may be complicated further for regulators if the affiliated company and the utility are both owned by a holding company. In that instance, purchases of goods and services by a utility may be made from an affiliate located outside of the state (and hence outside a utility commission's jurisdiction). Thus, geography, in addition to the holding company structure itself, would insulate the affiliate from regulators.[4] The result would be that access to the books and records necessary to determine whether an affiliate's charges for goods and services are fair could be less assured, especially if these two factors (geography and corporate structure) combine with the reluctance of corporate officials to cooperate with regulators, which is discussed below.

Cross-Subsidization

One of the potential disadvantages (from a ratepayer and regulator point of view) of an electric utility establishing and operating a subsidiary is the possibility of undue subsidization by the utility's ratepayers of the subsidiary's administrative (and other) costs. This would be in the form of a cross-subsidy between the utility and the subsidiary in which costs (especially joint or common costs incurred by both utility and subsidiary) are excessively allocated to the regulated utility portion of the company.

In its study of electric utility diversification, the Edison Electric Institute (EEI) discussed the problem of cross-subsidization, stating that "when the purpose of diversification is primarily to benefit stockholders, management must recognize that any cross-subsidy is improper. In all cases regulators will try to identify and remove such subsidies."[5] The report

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[4]See David P. Vondle and Elisabeth H. Ross, "The Regulation of Affiliated Interests," Public Utilities Fortnightly, June 7, 1984, pp. 32-37. The problems that holding companies posed for state regulators prior to the passage of the Public Utility Holding Company Act of 1935 are discussed in appendix A.

[5]Edison Electric Institute, Electric Utility Diversification: A Guide to the Strategic Issues and Options, vol. 1: Handbook (Washington, D.C.: Edison Electric Institute, 1983), pp. 91, 93.

recommends minimizing or avoiding shared costs (including personnel, facilities, services, or construction) or at least clearly documenting the allocation of the common costs.

The NARUC Ad Hoc Committee on Utility Diversification also analyzed the problem of cross-subsidization.[6] Its report noted that the FERC (and FCC) uniform systems of accounts cannot help regulators very much in dealing with cross-subsidization because those systems were not meant to track costs between companies. State regulators may thus have to develop new procedures for tracking and allocating costs between regulated and unregulated portions of the business. Developing such procedures will require understanding nonutility accounting and the types of costs incurred by the subsidiary. Even with the best accounting procedures, however, allocating some common or joint costs will be difficult. Different criteria will result in different cost allocations. (Accounting issues and methodologies are considered further in chapter 5.)

In addition to accounting problems, a state utility commission may encounter other problems in attempting to deal with cross-subsidization. A commission's staff would have to devote considerable amounts of time to the nonregulated subsidiary portion of the business, putting a further strain on already limited staff and budget resources. Another problem that regulators may face in trying to cope with cross-subsidization is denial of access to the subsidiary's books and records. Such access may be crucial to determining whether cross-subsidization has occurred. The Ad Hoc Committee report states that the utility may argue that a commission has no authority over the subsidiary's operations or that the information sought by the commission is proprietary.[7] Both of the problems just discussed, strain on staff resources and access to subsidiary records, are important obstacles faced by regulators not just in dealing with cross-subsidization,

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[6]See National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1982), p. 21.

[7]Ibid., pp. 27-28.

but also in regulating subsidiaries generally. They are discussed further later in this chapter.

Risk

Another important issue is whether a subsidiary might increase the utility's level of risk and as a result its cost of capital. On the one hand, a subsidiary may undertake a venture with the possibility of substantial gains, but a greater likelihood of failure than its utility parent. Such a venture might increase the utility's level of risk. On the other hand a subsidiary could lower a utility's overall risk and cost of capital by spreading the total corporate risk over more than one industry.

The NARUC report noted that utilities, in operating one type of business, are subject to variations in earnings within a narrower band than are other corporations. The situation is complicated by regulation that might be too slow to react to changes. Investors may consider utility diversification as a means by which to alter this situation. However, because diversification usually takes the utility into unregulated, competitive markets (which it hopes will yield a higher rate of return), the cost of capital for the combined regulated and unregulated activities of the corporation is likely to be higher than what it would be for the regulated utility by itself.[8]

An opposing argument, noted by the Congressional Research Service in a report on electric utility diversification, is that diversification could lower the diversified utility's cost of capital and reduce the consolidated corporation's overall risk even if the utility's subsidiary is more risky than the utility. The reduction in combined risk would occur if the subsidiary is likely to be flourishing at a point when the utility is enduring hard times and vice versa.[9]

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[8]Ibid., pp. 19, 30.

[9]See U.S., Congress, Congressional Research Service, Electric Utility Diversification, by Donald Dulchinos, Issue Brief No. 82060, updated November 5, 1984, p. 8.

Potential advantages of utility diversification for risk and the cost of debt to the utility are discussed in the EEI report. It contends that diversification can lead to improved stock prices for the utility and that better performance would result in a reduced cost of equity capital. Higher stock prices could also result in better bond ratings, reducing the cost of debt and thus the total cost of capital. Ratepayers would benefit from successful diversification because cost of equity and cost of debt, significant parts of their bills, would be reduced.[10]

Regulators may employ either of two possible approaches in setting rates for a diversified electric utility. A consolidated capital structure, including both regulated and unregulated parts of the corporation, would allow ratepayers to share in any benefits of the diversification. However, such a structure would also pass the increased costs of capital through to ratepayers. Regulators may want to use an imputed utility capital structure and capital cost in order to protect ratepayers from increased capital costs. However, the imputed structure would not allow ratepayers to share in any benefits that might result from the diversification.[11]

Return on Equity

One of the main reasons why a utility may establish subsidiaries is to assure a sufficient return to its investors. The rationale is that the financial woes of the electric utility industry, caused mainly by inflation and higher energy costs, have significantly diminished the returns earned by investors. Diversification by an electric utility (through the establishment of subsidiaries) into more profitable markets is offered as a potential partial solution to those financial problems.

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[10]Edison Electric Institute, Electric Utility Diversification, 1:16-20.

[11]National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification, pp. 19, 30.

One of the proponents of diversification as a means for utilities to use to improve returns to investors is Terry Ferrar, formerly of the Edison Electric Institute.[12] Ferrar, quoting Joseph Swidler, states that historically there was an "implicit compact" between regulators and electric utility investors. As a reward for investing in the regulated industry, investors were confident that regulators would grant them a fair return on their investment. In return, the utilities provided reliable service to their customers and rates declined.[13] According to Ferrar, inflation and high energy costs have resulted in the collapse of the compact. He states that utilities have continued to furnish cost-effective service with customers' cost of service in real terms remaining relatively stable during 1970 to 1980.

Ferrar argues that investors, however, have faced tougher times than ratepayers. He notes that from 1978 to 1980, the return on utility stocks was significantly below the rate of inflation. Investors thus received a negative return on their investment and as a result are demanding that utility management pay more attention to their interests.[14]

Similar points are made by Francis J. Andrews, Jr., a utility industry specialist at Deloitte Haskins & Sells, who states that investors have endured significant declines in the absolute values of their investments because of insufficient utility earnings and the sale of utility stock below book value. As a result, the market value of most utility stock is lower than it was ten to fifteen years prior to the time of the article (1982).

Andrews states that investors may no longer consider utilities to be minimal risk investments. The view is held by many investors that management has an obligation to the stockholders to investigate other

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[12]See Terry A. Ferrar, "Business Diversification: An Option Worth Considering," Public Utilities Fortnightly, January 7, 1982, pp. 13-18.

[13]Ibid., p. 13.

[14]Ibid., pp. 13-14.

business opportunities which would be more profitable to the utility's investors.[15]

In its study of electric utility diversification, the Edison Electric Institute stated that "during the past ten years, regulation has placed limitations on the upside [gain] potential of electric utilities without mitigating downside risk correspondingly; it is therefore not surprising that bond ratings, market-to-book ratios, and other financial indicators have fallen." The report conceded that the results of studies are not conclusive, but argued that diversification does appear to have improved the financial indicators of those regulated companies which have diversified. For example, one study conducted by Resource Planning Associates for EEI, found that in 1980 market-to-book and price earnings ratios for the diversified electric utilities studied were higher than for the nondiversified utilities. Market-to-book ratios were consistently higher for the diversified utilities for the period of 1967 to 1981 while price-earnings ratios were higher in twelve of those fifteen years. Another study by First Boston Corporation found market-to-book values of seven diversified electric utilities higher in 1981 than the industry average. The EEI also cited a Cabot Consulting Group report that stated that diversification can boost a utility's return on investment by 10 to 20 percent.[16]

Another commentator has argued that the ultimate corporate objective for a utility considering diversification must be to maximize shareholders' equity with the constraint of behaving in a socially acceptable manner. Utilities must add a second constraint: insuring that ratepayers will not be made worse off by the diversification.[17]

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[15]See Francis J. Andrews, Jr., "Diversification and the Public Utility Holding Company Act," Public Utilities Fortnightly, December 23, 1982, pp. 24-28.

[16]See Edison Electric Institute, Electric Utility Diversification, 1:10-16.

[17]See William B. Conerly, "Diversification: An Economic Framework for Analysis," Public Utilities Fortnightly, September 16, 1982, pp. 40-43.

Lower Fuel Costs

Another major motivation for utility management to establish subsidiaries is to lower costs by securing a dependable source of fuel for the utility. A utility may establish or acquire coal mines, and fuel transportation, development, and exploration companies. Such efforts by the utility may result in lower fuel costs although the study by Rozycki and Nelson, discussed earlier in this chapter, indicates that such a result may not always be the case. While utilities will approach this issue from a perspective of fuel price and supply stability, regulators will be concerned about potential problems, such as transfer pricing.

One way that a utility can lower its costs through fuel subsidiaries is by burning the right kind of coal (i.e., the type of coal for which the boiler is designed) in a power plant. Doing so avoids the declines in power plant performance that result when other, poorer types of coal are used.[18]

Poor performance caused by burning poorer quality coal, can result in significant costs to the utility. One study listed three types of costs: the cost of replacement fuel, increased operation and maintenance expenses, and unique costs associated with burning a poorer quality coal. The cost of replacement fuel consists of replacing the power lost from any outages. The source of this power may be more expensive. The authors of one study state that in cases where oil fired generators elsewhere on the system are used to replace the power lost in an outage, "every one percentage point decline in equivalent availability for a single 500-megawatt generating unit costs ratepayers over $1 million per year."[19] With respect to the increased operating and maintenance expenses, the costs of repairing a unit when it goes out of service may be greater than the costs of regular preventive maintenance. The unique costs include the costs of outages plus expenditures on such items as ash handling equipment.

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[18]See Marie R. Corio and Alice E. Condren, "Which Coal at What Cost?" Public Utilities Fortnightly, March 15, 1984, pp. 32-36.

[19]Ibid., p. 32.

Switching to the particular quality coal needed by the boiler, its design coal, to avoid the costs discussed above might not save money. Some design coals may actually cost 50 percent more than the poorer quality coal.[20]

Thus, by owning mines which provide the "right" type of coal, a utility can try to avoid significant outage and repair costs and guarantee that it will have a stable source of that fuel. Reliability of fuel supply would be another important reason for a utility to integrate vertically. By guaranteeing the availability of its fuel supply, a utility can remove some of the uncertainty and risk associated with obtaining an energy supply on the spot market. Spot market prices can fluctuate dramatically so that a utility would want to guarantee stability of price in the long-term (even if prices increase) by establishing its own fuel subsidiaries.

Synergistic Benefits

Utility management may establish subsidiaries to improve overall corporate performance. Combining two or more companies may yield a synergistic improvement in each firm's performance. Merging two profitable firms would result in a firm that could earn more profits than either of the two could separately. In the case of utilites it is argued that establishing or acquiring subsidiaries could result in such benefits and thus lower operating costs and lower rates. The problem for regulators is determining whether or not such benetits exist in a particular instance.

According to one observer, "the key to diversification is to identify the special skills of the company and the fields in which those skills are needed." In addition, "a company considering mergers as well as new ventures should examine its own special needs and which other companies might be able to fill those needs."[21]

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[20]Ibid., pp. 32-33.

[21]Conerly, "Diversification: An Economic Framework for Analysis," p. 41.

The Edison Electric Institute report also discussed the possible synergistic benefits of electric utility diversification. It argued that diversification would enable a utility to improve the utilization of its physical assets, personnel, and expertise. The report states that selling goods and services from a utility's subsidiary could lower rates and improve returns to investors. It described one utility, the Southern Company, that sells its expertise in planning and operating electric power facilities to other utilities and industries. Other examples in the report include real estate development on utility owned land, billing services for other utilities and use of utility rights of way. The report states that these types of diversification efforts have low start-up costs and low risk with the possibility of a high return on the utility's investment.[22]

Management Issues

Three major management related issues are discussed in this subsection. The first issue concerns a potential increase in utility management expertise that could result from diversification and the establishment of subsidiaries. Dealing with problems and issues in other markets may, it is argued, help a utility's managers sharpen their skills. Diversified utilities may also be able to attract more competent personnel. However, diversification could also lead to diversion of management and resources from the utility side of the business and a resultant decline in quality of service. A second major issue is that management may pursue a diversification program to further its own goals to the detriment of shareholders who after they have diversified their portfolios have little to gain from the utility's plans. The third major issue is whether utility managers have the expertise to undertake a program of expansion into unregulated markets. This is the counterpoint to the first issue. Diversification may, as argued, increase utility management expertise but lack of those

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[22]Edison Electric Institute, Electric Utility Diversification, 1:20-21.

necessary skills to begin with could lead to failure of the effort and also to diversion of management attention.

One of the potential synergistic benefits noted above was improved utilization of personnel. Francis Andrews states that diversification may make more efficient use of a utility's managerial resources by applying lessons learned in the utility industry to similar problems found in other industries. He asserts that managerial positions in multifaceted diversified utilities may attract higher quality personnel to fill those positions. A diversified utility should also be able to pay higher salaries to management than should a nondiversified utility. Higher salaries and the appeal of a multifaceted business should result in the utility being able to attract the best management available.[23]

In addition to higher salaries, other benefits of diversification for utility managers may include job security, power, and prestige. Management pursuit of such goals for itself may conflict with the interests of the firm's shareholders, however, and this possibility was discussed in an article in the Yale Law Journal.[24]

The author of the article uses portfolio theory to argue that diversification by a firm may produce conflict between management's interests and the maximization of shareholder wealth. Management is interested in diversification in order to reduce firm-specific risk (changes in returns to investors due to factors unique to the company) and to increase benefits to itself. Increased benefits to management result from the increased size of the firm, which adds to the firm's longevity and reduces the possibility of takeover attempts. Diversification thus increases management's job security, power, and prestige.

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[23]Andrews, "Diversification and the Public Utility Holding Company Act," pp. 26-27. Terry Ferrar makes some arguments similar to those made by Andrews (i.e., diversification leading to managerial development and attracting more talented people). See Ferrar, "Business Diversification: An Option Worth Considering," p. 16.

[24]"The Conflict Between Managers and Shareholders in Diversifying Acquisitions: A Portfolio Theory Approach," 88 Yale L. J. 1238 (1979).

Reduction of firm-specific risk has fewer advantages for investors with diversified portfolios, however. The author states that the wealth of an investor with a diversified portfolio is maximized only if returns from a company in which the investor owns stock are increased or market risk (changes in returns to an investor caused by general market changes) is decreased. Reduction of firm-specific risk through diversification by the firm does not create added value for the investor. Investors eliminate firm-specific risk through portfolio diversification and thus may not gain anything from management attempts to reduce that type of risk through diversification into subsidiary operations.

Investors may benefit from their firm's acquisition of another firm if operational or financial economies result and the acquisition is thus synergistic, with the value of the new entity greater than the sum of the values of the two, formerly separate firms. The acquiring firm must pay a premium over the current market value of the acquired firm's stock to that firm's stockholders in order to persuade those stockholders to sell their shares. The premium may be substantial and, once it is paid, the acquiring firm's shareholders cannot benefit from the transaction unless there are synergistic benefits in excess of the premium. According to the article, the empirical evidence suggests that an acquiring firm's long-run investment performance is not superior to the performance of nonacquiring companies, and randomly selected diversified portfolios have been shown to outperform conglomerates in both return on assets and accumulation of shareholder wealth.[25] Thus, the author concludes that acquisitions are

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[25]Ibid., pp. 1244-1247. Many of these assertions of adverse consequences to investors appear to apply to the case of firms acquiring unrelated businesses rather than to the case of horizontal or vertical integration. The author states that operational economies, the most common source of synergy, usually occur only in horizontal or vertical integration. The acquisition of an unrelated business may result in financial economies, such as transfer of funds among divisions, but operational economies rarely result in this case. The points made in this article about worsened corporate performance after an acquisition also provide an interesting contrast to the EEI's assertions of improved corporate performance resulting from diversification that were summarized earlier in this chapter.

not justified by any improvement in the performance of the acquiring company sufficient enough to make up for the costs of the transaction.

The third management related issue concerns the utility's ability to make its diversification effort succeed. While the establishment and operation of subsidiaries by an electric utility may benefit utility management by providing additional expertise, the lack of such entrepreneurial skills to begin with may endanger the success of the diversification effort. Utility managers are accustomed to life in a regulated environment in which their utility is a natural monopoly. Whether they would be able to adapt to life in a competitive, riskier environment is an important concern of ratepayers and regulators.

One observer has discussed this problem in the case of an electric utility diversifying into nonrelated products. Such diversification moves utilities into areas in which they have no technological, managerial, or competitive experience. The utility would have to mix the management approach of a highly regulated utility with the entrepreneurial approach needed in a fast-changing competitive market. Skills needed to manage a diversified business would have to be acquired and employed without taking management's attention away from the utility itself.[26] Hence the utility's public service mission may be lost. Public utility managers may place the goal of insuring the success of their subsidiaries ahead of the goal of providing adequate and reliable utility service at the lowest reasonable cost.

As one of its conclusions, the NARUC Ad Hoc Committee on Utility Diversification observed that utility executives have strong incentives to insure that their diversification efforts succeed. According to the report, failure of such ventures would be highly visible, and regulators would probably not allow the utility to recover its losses from the ratepayers. The report states that "therefore regulators should be aware that the management of [a] diversified utility may be tempted to divert

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[26]See Arthur A. Thompson, "The Strategic Dilemma of Electric Utilities - Part II," Public Utilities Fortnightly, April 1, 1982, p. 24.

managerial talent and financial capital from the utility if diversified activities develop pressing problems."[27]

Management attention may be diverted for other reasons besides the subsidiary developing "pressing problems." If the subsidiary paid higher salaries than the electric utility paid, the morale of the utility's management might be undermined. In addition, the utility's executives might leave the utility in favor of the nonutility positions. The NARUC report states that "managers working on both utility and nonutility projects simultaneously are placed in a difficult position if rewards are unequal."[28] Thus, for a variety of reasons, electric utility management may subordinate its original public service mission in favor of ensuring subsidiary success.

The Edison Electric Institute, on the other hand, states that concerns that an electric utility may foresake its public service mission when diversifying are unwarranted. The report states that "the fundamental responsibility of every electric utility is to provide safe, reliable, and adequate supplies of electricity to their customers at reasonable cost." The EEI notes that electric utilities have a legal duty to meet this responsibility and that state utility commissions have the appropriate authority to insure that utilities do meet this obligation.[29]

Technological Progress

An electric utility may establish subsidiaries to foster technological progress. These efforts could be directed at either the supply or demand side of the business. A utility may want to be at the forefront of

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[27]See National Association of Regulatory Utility Commissioners, <u>1982 Report of the Ad Hoc Committee on Utility Diversification</u>, p. 78.

[28]Ibid., p. 17.

[29]See Edison Electric Institute, "Comments of the Edison Electric Institute on the Preliminary Official Report of the NARUC Ad Hoc Committee on Utility Diversification," in <u>Electric Utility Diversification</u>, vol. 2: <u>Regulation</u>, p. 4.

changing developments in the industry. It may want to try to influence those developments and thus it will establish subsidiaries to work on new innovations in the supply of or demand for electricity. As with other utility diversification efforts, however, regulators will be concerned about transfer pricing (if the subsidiary sells any new technologies to its parent), and cross-subsidization. The riskiness of the new ventures would also be a special concern.

With respect to the supply of electric power, one analyst contends that large power plants no longer produce economies of scale, and the technology currently employed in those large plants may soon become obsolete.[30] As a result, a utility may set up a subsidiary to explore new generating technologies, such as solar photovoltaic and fuel cells and various types of cogeneration facilities.

With respect to influencing demand, a utility may seek to increase its off-peak demand by encouraging the development of new markets (and new technologies) for off-peak electricity. One example would be electric vehicles, which could be recharged at night. Another would be thermal energy storage in which customers heat or cool a substance, such as water, during off-peak hours to use for space heating or cooling during peak hours. The latter example has the increased advantage, from a cost perspective, of decreasing demand during peak hours and thus diminishing the need for new capacity.[31]

Another way in which an electric utility may try to influence demand is through conservation-related technologies. A utility may work to develop new energy-saving devices for its customers to use. For example, EPRI reports that the Tennessee Valley Authority has been working with new solar technologies.[32]

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[30]See John S. Ferguson, "Is Central Station Generation Becoming a White Elephant?" Public Utilities Fortnightly, March 21, 1985, pp. 32-34.

[31]See Kevin A. Kelly, "Follow-on Markets to Time-of-Day Pricing," in New Telecommunications Opportunities for Non-Telephone Utilities (Arlington, VA: Public Utilities Reports, Inc., 1985), pp. 140-146.

[32]"Demand Planning in the '80s," EPRI Journal, December 1984, p. 8.

A utility may establish a subsidiary to explore new supply and demand technologies instead of conducting such activities internally because of the higher risk involved in the development of such technologies. In addition, the utility might want to isolate these activities and insure that investors receive more of the benefits.

Electric utilities have also worked together to foster technological development. An example is the Electric Vehicle Development Corporation, that has been formed by a group of electric utilities to promote the commercialization of electric vehicles.

According to one analyst, regulators must allow electric utilities sufficient organizational flexibility to react to changes in the utility industry.[33] Such flexibility is seen as necessary for technological innovations. Thus, utility management may view subsidiaries as an important means for achieving technological development and for maintaining the future financial health of the industry.[34]

As just noted, the development of new technologies is a riskier proposition for the utility than is its usual business. Because of this higher risk, there is greater potential for harm to ratepayers. Thus, commissions may be forced to decide if the potential benefits to society of a new technology are worth subjecting ratepayers to the additional risk.

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[33]Ferguson, "Is Central Station Generation Becoming a White Elephant?" p. 34.

[34]See Thompson, "The Strategic Dilemma of Electric Utilities--Part II," p. 23. Thompson discusses some of the problems an electric utility would face in attempting to diversify to facilitate technological progress and to develop alternate energy sources. He notes that electric utilities will be "entering a...research and development (R&D) race against some cash-rich, technologically talented companies" such as Exxon and General Electric. Prevailing customs and traditions found in the electric utility industry may inhibit the development of fresh approaches and fresh technologies. Thompson also notes that "it is questionable whether electric utility companies have the financial flexibility or the technical resources to explore the broad technological front of new electric generation alternatives." Utilities pooling their research and development efforts would not necessarily result in major breakthroughs. Thompson states that "the best that might be hoped for is to be in a technological position to duplicate the breakthroughs that outsiders are likely to make first."

This section identified eight issues arising from the establishment and operation of subsidiaries by electric utilities. They cover a variety of potential benefits and injuries to the utilities, and their customers. They also represent some significant challenges to regulators.

Commission Authority

The extent of state utility commission authority to allow or disallow the establishment of subsidiaries, to require divestiture by an electric utility of its subsidiaries, to regulate the subsidiary through its parent utility, and to regulate transactions between a utility and its subsidiaries is covered here, insofar as these are known from previous writings. Admittedly, much of the discussion on commission authority deals with utility holding companies which are not the major concern of this report. This reflects the bias of the literature to a large extent. It is likely that much of the authority and many of the conditions discussed here applying to holding companies apply also to subsidiaries.

Allow/Disallow Establishment

A commission with the authority to allow or prohibit the establishment of subsidiaries by electric utilities would become involved in a utility's diversification plans relatively early. The commission would actually have the ability to say whether or not those plans could proceed. Thus, such authority may be valued by a state commission that views itself as an active, rigorous protector of the public interest. Utilities, however, may view this authority as another obstacle to be overcome and an unnecessary complication for their plans. In their view, commissions have other ways to express their views on a utility's diversification, and commission input to the formation of subsidiaries should be voluntary and not obligatory.

With respect to the authority of state utility commissions to approve or prohibit the establishment of subsidiaries by electric utilities, the view held in some of the literature is that state regulators generally have such authority. For example, one study states that "generally speaking, a PSC's authority over any such activity [utility diversification] is quite broad; in particular, its authorization is required both for the establishment of the new subsidiary and for the funding. The same situation normally obtains in acquisitions directly by the utility."[35]

A survey of fifteen state commissions by McKinsey & Company found that in up to nine of those states, the commission might have authority to approve or disapprove formation of an unregulated subsidiary. This total included five of the fifteen commissions stating that they definitely had such authority; one which said that they were not sure but that they would assert this authority, one which said that they had authority if stock were issued and two which said that they were not sure.[36]

A different view on the extent of commission authority is taken by the Edison Electric Institute (EEI) which states in its study of electric utility diversification that few state utility commissions have explicit statutory authority over corporate reorganization. The EEI states that some commissions may attempt to regulate diversification by regulating affiliate transactions, rates, dividends, etc., while other commissions (Illinois and Wisconsin) may try to assert authority over corporate reorganization.[37]

The EEI report also discusses some examples of state actions and authority over establishment. For example, the Maine legislature passed a bill in 1982 requiring utility corporate reorganizations to be approved by the state utility commission. In that same year, an order by the Montana Commission delaying a Montana Power Company reorganization effort until the

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[35]See Douglas W. Hawes, Utility Holding Companies (New York: Clark Boardman Company, Ltd., 1984), pp. 8-2 - 8-3.

[36]Lester P. Silverman, McKinsey & Company, Inc., personal letter, March 20, 1985. The fifteen states surveyed were California, Connecticut, Louisiana, Maryland, Massachusetts, Michigan, Montana, New Mexico, New York, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, and Wisconsin. The survey also found that in three of the states, the state utility commission had authority to approve or disapprove a utility's diversification plans.

[37]Edison Electric Institute, Electric Utility Diversification, 1:81. This discussion is mainly concerned with utility diversification through a holding company structure.

Commission could investigate was upheld in court. However, the Commission did not assert and the court did not approve any authority to allow or disallow the formation of a holding company. In 1983, the Massachusetts Department of Public Utilities turned down Boston Edison's application to reorganize for diversification purposes. The Department acknowledged the potential benefits of utility diversification but did not want to approve the plan without seeing more details in order to assess more fully the effects on ratepayers.[38]

In addition to simply approving or disapproving (i.e., merely saying yes or no to) an electric utility's plan to establish a subsidiary, a state utility commission may approve that plan but attach conditions to its approval. Douglas Hawes, a prominent attorney specializing in securities law, discusses several types of conditions that state regulators have imposed in approving utility plans to establish holding companies.[39] These conditions include first, guaranteed access to books, records, and other documents of the utility or its affiliates; second, review and approval (or disapproval) of transactions between the affiliated companies under the holding company; third, guarantees that the utility's credit will not be harmed, and that its ability to raise capital and to provide adequate service will not be hurt; fourth, limits on the total level of corporate investment in nonutility ventures; and fifth, commission authority to order the divestiture of the utility from the holding company if necessary to protect the interests of the utility ratepayers, or investors. While Hawes' discussion applies to the case of a utility establishing a holding company, similar conditions could probably be imposed by a commission when considering an electric utility's request to establish subsidiaries.

J. Robert Malko, Gregory B. Enholm, and Theodore M. Jaditz of the Wisconsin Public Service Commission discussed some of the conditions that

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[38]Ibid., pp. 82-83. See also section 2, "Effect of State Laws and Regulations on Utility Diversification," in volume 2 of the EEI study, Regulation, especially pp. 36-51. This discussion is also mainly concerned with utility holding companies. The Massachusetts order is abstracted in appendix C.

[39]Hawes, Utility Holding Companies, pp. 4-34 - 4-41.

specific states have attached to their approvals of utility holding company structures. For example, the Hawaii Commission specified in a 1971 case involving the Honolulu Gas Company that the holding company "shall furnish...any and all records, books or documents of every nature and kind when requested in writing by said commission." The Commission also required quarterly and annual financial statements for each company under the holding company plus explanations of intercompany transactions and cost allocations. In 1978, the Connecticut Public Utilities Control Authority required that the books and records of a holding company (and its subsidiaries) being formed by Southern Connecticut Gas Company be readily available to the Authority and its staff for inspection.[40]

Divestiture

The authority to require an electric utility to divest its subsidiaries would be a major tool for a state commisson to possess. As in the case of authority to approve or disapprove establishment of subsidiaries, an activist commission would value such a tool as an important means for protecting ratepayers if a subsidiary was absorbing too much of the utility's resources, leading to deterioration of service to the public. Utilities, however, see this type of commission authority as a perpetual, potential threat to the success of their subsidiaries. In their view, any setback suffered by a subsidiary could be used by overzealous regulators to order divesture. The result would be that the subsidiary would not be

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[40]See J. Robert Malko, Gregory B. Enholm, and Theodore M. Jaditz, "Energy Utility Diversification, Holding Companies, and Regulation," paper presented at the Fourth Annual Public Utilities Conference of New Mexico State University, El Paso, Texas, October 1981, pp. 21-22. The EEI notes that in 1982 the Hawaii Commission approved the Hawaiian Electric Company's application to form a holding company with conditions that included the Commission's right to investigate transactions between the utility, its subsidiaries, and the holding company, the right of the Commission to review the allocation of common costs, restrictions on the divestiture of the utility and the assertion of authority by the Commission over the issuance of utility securities. See Edison Electric Institute, Electric Utility Diversification, 1:83.

given the chance to succeed and potential benefits of diversification could be lost.

The NARUC Ad Hoc Committee observed that state commissions may not possess adequate legal authority to control divestiture of diversified activities from a utility in that utility diversification is a relatively new phenomenon for many states. The Committee stated that regulators should be able to order either the divestiture of a utility from its holding company parent or the divestiture of a subsidiary from a utility if they find that diversification is seriously harming the utility and its ratepayers. The report notes, however, that use of this power "could indicate a situation too far deteriorated to remedy," and that "this may prove to be an ineffective regulatory tool under some circumstances, but it is needed to protect utility ratepayers."[41]

Not suprisingly, the Edison Electric Institute expressed reservations about any regulatory power to order divestiture. It noted that utility management was responsible to the utility's shareholders for avoiding situations that may become too far deteriorated to remedy. In addition, the report stated that a commission might use its authority to order divestiture after one or two years of poor performance by the diversified venture. The EEI stated that such a brief period of poor performance may not indicate managerial imprudence. According to the report, "it is important to consider potential long-term performance, an issue that state commissions may not have the expertise or ability to evaluate."[42]

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[41]National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification, pp. 16, 82. The Ad Hoc Committee also noted that state commission authority to control divestiture of a utility from a holding company may be vague or nonexistent due to federal regulation of utility holding companies under the Public Utility Holding Company Act of 1935. The Committee notes that state regulators may need to request an opinion from their state attorneys general or work on new state legislation to clarify their authority.

[42]Edison Electric Institute, Electric Utility Diversification, 1:84-85.

The EEI stated that if a commission had authority to order divestiture, it might be pressured by the competitors of the diversified business to use that authority for reasons other than the financial health of the subsidiary. The EEI concluded that "on all these counts, commission jurisdiction to order divestiture would increase the risks of entry into such businesses, and reduce the potential for benefits from them."[43]

In his discussion of utility holding companies, Hawes makes the point that giving a commission the authority to order a holding company to dissolve or divest itself of a utility or a nonutility subsidiary "may instigate an unnecessary and undesirable change in the chemistry between PSCs and utilities under holding companies." Rate cases make the coexistence of regulators and regulated difficult enough. Hawes states that it appears unnecessary for state commissions to have the authority to order divestiture unless the exercise of such power would be limited to emergencies. However, he also observes that it might be reasonable to allow a state utility commission to include in its approval of the formation of a holding company the stipulation that divestiture or dissolution may be ordered if the utility intentionally violates any of the conditions that the commission may have imposed in approving the holding company's formation. The order to divest or dissolve would be subject to certain procedural safeguards for the utility including the right to remedy the violation of the orders in the commission's approval.[44]

The views summarized here give an indication of the seriousness with which the authority to order divestiture is viewed by both regulators and electric utilities. Some regulators want to be able to exercise this authority although it is not viewed as the best possible cure for the regulatory problems presented by electric utility subsidiaries. The industry is afraid that regulators may use their authority in a less than responsible manner, complicating their business planning.

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[43]Ibid.

[44]Hawes, Utility Holding Companies, p. 4-48.

Regulation of the Utility-Subsidiary Relationship

Commission regulation of the utility-subsidiary relationship encompasses a variety of related issues. Some of these are procedural issues, such as access to books and records, and are covered later in this chapter. The main question is: given that a subsidiary exists and functions, how far should a commission go in attempting to eliminate such potential abuses as transfer pricing and cross-subsidization? Commissions can make use of affiliated interest statutes, cost allocation methods, or rate of return modifications, to name just a few categories. These would be alternatives to more extreme measures such as not allowing the formation of the subsidiary in the first place or ordering its divestiture. Utilities may feel that commissions have no need for the more extreme measures because other alternatives, such as those listed here, are sufficient to protect the public interest. As the following subsection shows (and as is discussed further in chapters 4, 5, and 7), there are a variety of powers and methods for commissions to employ. The following discussion covers both regulating the subsidiary through its parent utility (instead of regulating the subsidiary itself directly) and overseeing transactions between the utility and its subsidiaries.

Some states have enacted affiliated interest statutes to give commissions explicit authority to regulate the relationship between a utility and its subsidiaries or holding companies. These laws guarantee the right of utility regulators to examine transactions between the utility and the subsidiaries or holding companies in the absence of arm's length negotiations in the transactions. Many of the affiliated interest laws were enacted in the 1930s. They enable regulators to gain access to the books and records of affiliated companies, to obtain documentation of the costs of goods and services that a utility and its affiliated companies may provide to each other, and to approve or disapprove contracts so that utilities will not be dealt with unfairly (and hence jeopardize the public interest).[45]

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[45]Ibid., pp. 4-42 - 4-43, and pp. 10-2 - 10-3.

The Edison Electric Institute noted in its study that state commissions may have the authority to review affiliate transactions even if specific statutory authorization to do so is absent. In some states where the issue has arisen, courts have upheld the implied authority of regulators to review the transactions under a commission's general ratemaking powers. In those cases, the courts considered the power to review the affiliate transactions to be a logical consequence of a commission's authority to examine a utility's expenses in order to insure that unreasonable costs for goods and services are not passed through to the utility's customers.[46]

One study of the regulation of the affiliated businesses of a holding company found that while state utility commissions do not have direct authority to regulate the prices charged by an affiliate for goods and services, they may use other powers to discourage indirectly potential abuses that could result in increased charges to ratepayers. For example, in a rate case a commission may require a utility to justify affiliate charges for goods and services provided to the utility. A utility may also have to prove that the affiliate is not making an unreasonable profit. If a utility cannot satisfy these requirements, the commission might not allow it to recover the costs of the affiliate's charges in its rates. The commission may also have the authority to review contracts made between a utility and an affiliate. The utility may have to prove that the charges in a contract are justified before the commission will give its approval.[47]

In addition to review of transactions between an electric utility and its subsidiaries (or affiliates), a commission can regulate the relationship between a utility and its subsidiaries through its power to review the allocation of costs between the utility and the diversified venture. As mentioned previously, the NARUC Ad Hoc Committee on Utility Diversification

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[46]Edison Electric Institute, "Effect of State Laws and Regulations on Utility Diversification," p. 13.

[47]Vondle and Ross, "The Regulation of Affiliated Interests," pp. 34-35.

discussed the problems of accounting procedures and cost allocation in its report. That report stated that allocations may differ as a result of the varying criteria which could be used by regulators. The Ad Hoc Committee suggested that regulators may need to develop new procedures.

Even with its difficulties, cost allocation still represents an important means for state commissions to regulate electric utility dealings with subsidiaries. The EEI found that some state commissions are authorized specifically by statute to review the allocation of costs between a utility and its subsidiaries, but that all commissions may assert their authority to allocate costs in the course of ratemaking. For example, the Hawaii Commission approved the Honolulu Gas Company's reorganization as a subsidiary of a holding company. In doing so, the commission stated that it could review the allocation of such costs as the salaries of individuals working for both the utility and the holding company's other businesses, expenses for facilities including rent and taxes, expenses for such outside services as advertising and legal counsel, and expenditures on construction projects. The commission stated that it would not include any allocations that it did not consider proper in its calculations of rate base, expenses, and rate of return. The EEI report notes that in cases where a commission has not asserted authority over a subsidiary, the regulators may still feel that it is within their power to disallow any cost allocations between the utility and the subsidiary that the commission considers unreasonable.[48]

Another method that regulators may use to oversee the relationship of a utility with its subsidiaries is to modify the utility's allowed rate of return to take into consideration the nonutility operations. As described above, the Hawaii Commission stated that it would exclude any costs that it considered improperly allocated from the calculations of a utility's revenue requirement. Many commissions have sought to determine how a utility's other business ventures have affected its cost of capital. The regulators

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[48]Edison Electric Institute, "Effect of State Laws and Regulations on Utility Diversification," pp. 20-21; and Edison Electric Institute, Electric Utility Diversification, 1:93.

have adjusted this cost to include the effect of the utility's subsidiaries when they have derived the utility's rate of return. The EEI report observed that the commissions' authority to make such adjustments is based mainly on their mandate to insure "just and reasonable" rates, although a few states' statutes explicitly authorize commissions to allocate capitalization, earnings, and debt between a utility and its nonutility businesses.[49]

Regulatory Practices

This section covers some of the practices that are reported in the literature as being used by state commissions to regulate electric utility subsidiaries. This review is not meant to be a comprehensive listing of all practices currently employed by all state commissions, but merely a description of some of the major steps taken by regulators.

Regulating the Subsidiaries

This subsection summarizes some actions taken by state commissions to regulate electric utility subsidiaries. It was stated earlier that a major concern for regulators is how far to go in regulating s subsidiary. An additional issue is at what point in a utility's diversification process a commission should intervene. Discussion of Wisconsin's rules shows how one commission coped with those issues. The Montana case provides an example of a commission deciding that it could not regulate a subsidiary's sales directly, but it could attempt to regulate the amount of the utility's investment in the subsidiary that appeared in the utility's rates.

The case from Montana involved Montana-Dakota Utilities and its wholly-owned subsidiary Knife River Coal Company. The issue of how much the utility's ratepayers should pay for the coal supplied by the

[49]Edison Electric Institute, "Effects of State Laws and Regulations on Utility Diversification," p. 23.

subsidiary arose in a rate case in 1978. Knife River supplied all of Montana-Dakota's coal, but the sales to its parent represented only about one-third of the coal company's total sales.

The Montana Public Service Commission decided that it could not regulate the coal company's sales, but it did place a limit on the level of Montana-Dakota's coal expenses that could be included in rates. The Commission applied Montana-Dakota's return on equity to the amount of Knife River's fixed investment that could be attributed to the Montana portion of the utility's total expenses. In doing so, the Commission rejected Montana-Dakota's position that its return on equity should be applied to the fair market value of Knife River's assets instead of to the original cost of those assets.[50]

Another approach to regulating electric utility subsidiaries was advocated by the New York Public Service Commission. The Commission's Chief of Accounts, Everett L. Morris, argued for a policy of excluding the utility's investment in nonutility activities from equity when calculating the utility's allowed earnings. Otherwise the subsidiary might obtain higher utility-derived earnings. Because no New York utility based its mortgage bonds on nonutility property and utility and nonutility securities were rated differently, Morris contended it would be wrong to assign the cost of

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[50]The utility appealed this ruling, and in 1981 the Montana Supreme Court remanded the case to the Commission for additional hearings. The Court ordered the Commission to (a) establish a basis for the rate of return allowed the coal company (if using a rate-of-return method) that takes into consideration Knife River's assets and a comparable rate of return that would be earned by other coal companies; or (b) supply the facts needed (if using a market cost of coal method) to support the Commission's conclusion about the fair market price of coal. The Court felt it was not reasonable to limit Knife River's earnings on sales to its parent utility to the return allowed the parent. The discussion of this Montana case is taken from Gregory B. Enholm and J. Robert Malko, "State Regulatory Treatment of Electric Utility Diversification," in <u>Electric Power Strategic Issues</u>, eds. James Plummer, Terry Ferrar, and William Hughes (Arlington, Va: Public Utilities Reports, Inc., 1983; Palo Alto, Ca: QED Research, Inc., 1983), pp. 320-322.

the utility's debt to the nonutility part of the business. The idea is to separate the utility from its nonutility activities when calculating a revenue requirement so that the utility will be neither helped nor hindered by its subsidiary, and vice-versa.[51]

The Wisconsin Public Service Commission has been involved with the issue of electric utility diversification since 1981 when Wisconsin Power & Light and Wisconsin Electric Power each applied to the U.S. Securities and Exchange Commission to form holding companies for diversification purposes. Since then, the Wisconsin Commission has been a leader in dealing with the regulatory issues and problems posed by electric utility subsidiaries, and it is useful to discuss some rules that this Commission has considered since that time.

After deciding in October 1981 that it had authority under Wisconsin's affiliated interest statute over the formation of a holding company by a utility, the Wisconsin Commission proposed a rule designed to cover reorganizations that resulted in the creation or dissolution of a holding company by a public utility. It would have required the written approval of the Public Service Commission for any such corporate reorganization. The utility would also have to obtain a certificate from the Commission before exchanging, modifying, cancelling, or converting any of its securities in order to implement the reorganization. In order to obtain the certification, the utility had to demonstrate that the investors would be protected. Once in existence, the holding company or any subsidiaries of the utility would have to obtain Commission approval before issuing any securities. The utility also had to demonstrate that the proposed reorganization was in the public interest. The Commission was to monitor the operation of the holding company and other nonutility businesses or investments that the

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[51]Ibid., pp. 323-324. Also, the Congressional Research Service reports that the New York Public Service Commission was using a case-by-case approach to handle requests by utilities to diversify. Approval of a utility's plan was contingent on the type of cost allocation procedures incorporated in the plan as well as the utility's explanation of why the plan was in the public interest. See U.S., Congress, Congressional Research Service, Electric Utility Diversification, p. 12.

utility might have. If the Commission decided that the impact of the reorganization had not been in the public interest, it could order the dissolution of the holding company or the divestiture of the utility's other investments and businesses.

In March 1982 the Wisconsin Commission changed its position on its authority over utility reorganizations. The proposed rule was redrafted. The Commission decided that utilities' holding companies were not to be regulated as public utilities, but the regulators continued to assert authority over the formation of the holding companies. The new rule required a utility's application to the Commission to form a holding company to include the details and purposes of the corporate reorganization as well as a discussion of the corporate restructuring's impact on the utility's financial structure and customer service. Under the proposal, the Commission had the power to determine whether the utility's plan was in the public interest and to alter the plan if the regulators decided that such was not the case.[52]

This description of the Wisconsin Public Service Commission's two proposed rules is useful not only because it shows two approaches considered by a leading commission for regulating utility holding companies and subsidiaries but also because it illustrates dilemmas facing regulators. The first approach was stringent with close regulatory supervision of holding company and subsidiary operations. The second approach focussed on the beginning of the diversification process, concentrating on holding company and subsidiary formation. In the process of the shift from the first to the second rule, the Commission appeared to take a more restrictive view of its own authority. The two issues or dilemmas for regulators

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[52]Edison Electric Institute, "Effect of State Laws and Regulations on Utility Diversification," pp. 46-50; see also Enholm and Malko, "State Regulatory Treatment of Electric Utility Diversification," pp. 325-327; and Stanley York, Phyllis Dube, and J. Robert Malko, "Electric Utility Diversification: A State Regulatory Perspective," in Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries: Proceedceedings of the Institute of Public Utilities Thirteenth Annual Conference, ed. Harry M. Trebing, MSU Public Utilities Papers (East Lansing, Michigan: Institute of Public Utilities, Michigan State University, 1983), pp. 580-584.

mentioned earlier are deciding at what point to intervene and how far to go. Extensive regulation of a subsidiary will leave a commission open to criticism that it is attempting to accomplish a task (i.e., regulation of an entity in another market) for which it lacks the expertise. Extensive regulation of the subsidiary will also further stretch scarce commission resources. On the other hand, if a commission decides against closely regulating a utility subsidiary, it may come under attack from consumer groups, legislators, and others for not being sufficiently aggressive guardians of the public interest.

The NARUC Ad Hoc Committee recommended against the regulation of a nonutility subsidiary that is under a holding company.[53] The Committee recommends a middle ground between the two positions discussed before, suggesting that regulators become extensively involved in the affairs of a subsidiary only when problems develop.

Regulating Affiliate Transactions

Closely related to the regulation of a subsidiary is the regulation of transactions between the subsidiary and the electric utility. As noted earlier many commissions have authority under affiliated interest statutes to regulate those transactions. How commissions actually exercise the authority given to them is the major issue here. The different standards that a commission may employ can have different impacts on the utility and the subsidiary's rates of return. Commissions are concerned about the problems of transfer pricing abuse that arise in affiliate transactions between a utility and its subsidiary. At the same time, utilities want to be able to reap the benefits from their investment in a subsidiary. Both sides have legitimate interests and a careful balance must be struck between the two.

The Edison Electric Institute report noted that state commissions employ one of two standards in regulating affiliate transactions. Each

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[53]National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification, p. 81.

standard views the subsidiary differently.[54] The first standard, the market test or traditional approach, is based on a view of the subsidiary or affiliate as an independent company. A commission using this approach would compare prices charged by the subsidiary (in its transactions with the utility) with the prices charged by similar companies for similar goods and services. The reasonableness of the transaction can also be judged by comparing the price charged by the subsidiary to the utility with the price charged to a nonaffiliated customer for the same goods or services. If the price charged to the utility is similar to charges in arm's length dealings, the expenses would be allowed by the commission. Any excess in the charges would not be allowed.

The EEI notes that commissions may add other conditions to the market test. These additional tests include permitting as a reasonable utility expense that portion of the subsidiary's charges (to the utility) that allow it to earn a rate of return on the portion of its business done with the utility that is comparable to the rates of return earned by similar businesses. A reasonable rate of return for comparison in this case might be the average of the return rates of either industrial corporations or the type of corporation thought to be comparable in risk to the subsidiary.

The second major standard employed by state utility commissions in regulating affiliate transactions is identified by the EEI and others as "the California approach". Unlike the market test approach, which viewed the subsidiary as independent, this standard, which resulted from a series of commission and judicial decisions in California, treats the subsidiary as a part of the utility. Under this procedure, any charge made by a subsidiary or affiliate to a utility that would enable the subsidiary or affiliate to earn a higher rate of return than the utility would not be allowed. In cases in which the subsidiary (or affiliate) does business with other customers besides the utility, regulators have applied the

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[54] Edison Electric Institute, Electric Utility Diversification, 1: 95-96; and volume 2, section 2 of that study, "Effect of State Laws and Regulations on Utility Diversification," pp. 13-17. The standards that a commission can employ in regulating affilate transactions are discussed more fully in chapter 7.

limitation on the subsidiary's returns only to the transactions with the utility.

Hawes also discusses the various standards used by commissions to regulate affiliate transactions.[55] The three approaches discussed include a cost procedure under which the utility commission analyzes the costs to the subsidiary of providing the goods or services to the utility. The commission then limits the utility's payments to the subsidiary to what is sufficient to cover those costs, including some return on capital.[56] The second approach is the market price method, using as the basis for comparison either the prices of goods and/or services sold by the utility's subsidiary to nonaffiliated customers or the market price for the goods and services. This is the traditional method discussed by EEI. Hawes' third approach is the comparable returns approach in which the regulatory commission allows only those prices that will enable the subsidiary to earn a rate of return that is comparable to that of similar companies. He notes that this method is more complex than the market price method and thus increases the burden on regulators.

Other analysts have discussed some practices that various states have used to oversee transactions between a utility and affiliated companies when all are under a holding company. For example, many state commissions may require a utility to justify an affiliate's charges for goods and services. In Alaska a utility must document the affiliate's cost of providing a service. In addition, the utility must show that it could not have provided the good or service more cheaply itself. Other states (California, Iowa, Michigan, New York, and Washington) require the utility to show that the affiliate has not made an unreasonable profit in its transaction with the utility.

With respect to commission authority to review contracts between a utility and an affiliate, utilities in New York must prove to regulators that charges in the contracts are reasonable before the contract can go

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[55]Hawes, Utility Holding Companies, pp. 10-3 - 10-6.

[56]Hawes states that this method was developed in California, and he cites the same cases that the EEI used in its discussion of the California method. In short, Hawes is discussing the same standard although he emphasizes a different aspect of it.

into effect. Maine utilities must secure the approval by that state's utility commission of any contracts with affiliates before the affiliates can provide any services to the utilities.[57]

Access to a Subsidiary's Books

A third type of state utility commission practice is regulatory policy with respect to access to a subsidiary's books. In order to regulate the utility-subsidiary relationship effectively and deal with such problems as transfer pricing abuse and cross-subsidization, regulators argue for access to appropriate books and records. As described in appendix A, securing access to these documents was a major problem for state commissions during the era of holding company dominance and is still a point of contention between regulators and utilities. While regulators are concerned about transfer pricing and cross-subsidization, utility managers may feel that the subsidiary's operations are beyond the scope of the state commission's authority and that they should thus not have to surrender corporate records to commission inspection. The utility's managers may also be concerned about the possibility of important corporate plans and secrets being leaked to competitors (of the subsidiary, if any) if those plans or secrets are shown to any outsiders, including commission staff.

The NARUC Ad Hoc Committee on Utility Diversification recommended that state commissions have the authority to inspect a holding company's books (as well as the books of its subsidiaries) if necessary to deal with problems arising in a utility. In addition, Hawes notes that affiliated interest statutes often give state utility commissions authority to examine the books and records of utility subsidiaries.[58] Some states have required guaranteed access to a subsidiary's books as a condition of their approval of the subsidiary's formation. Hawaii and Connecticut are two

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[57]Vondle and Ross, "The Regulation of Affiliated Interests," pp. 34-35.

[58]National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification, p. 81; Hawes, Utility Holding Companies, p. 4-43.

Wisconsin's proposed rules included a stipulation that holding company books, records, and accounts be accessible to the Public Service Commission.[59] The New Mexico Public Service Commission proposed a rule (Proposed General Order No. 39) that covers a variety of regulatory concerns over utility diversification including access to books and records. Among its provisions, the order specified that the books and records of the utility were to be kept separately from those of any nonregulated businesses. In addition, the Commission and its staff were to have access to the books and records of the nonutility businesses (plus any other information on those operations that the Commission needed).[60]

Commission Expertise and Regulatory Costs

Parallel to the argument that utilities may not possess the skills needed to diversify successfully into new markets is the argument that state utility commissions may not be able to monitor or regulate companies in markets with which the regulators may have little or no familiarity. Regulators may be able to examine a subsidiary's books and records, but the question here is whether they can evaluate such information in a fair and knowledgeable meanner. Utilities are also concerned with the issue of commission expertise, and they may feel that the state utility commissions do not have the ability to evaluate their subsidiaries' operations. An additional regulatory concern is that the actions that a commission takes to acquire the expertise needed to oversee a subsidiary, whether diverting existing staff or hiring new staff, may be costly to it.

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[59]Malko, Enholm and Jaditz, "Energy Utility Diversification, Holding Companies, and Regulation," pp. 21-22; York, Dube, and Malko, "Electric Utility Diversification: A State Regulatory Perspective," p. 584; and Edison Electric Institute, "Effect of State Laws and Regulations on Utility Diversification," p. 50.

[60]Leonard A. Helman, "Diversification - Does the Public Service Company of New Mexico Case Predict Similar Reaction Elsewhere?" in Proceedings of the Third NARUC Biennial Regulatory Information Conference, ed. Daniel Z. Czamanski, p. 195. General Order No. 39 is abstracted in appendix C.

The NARUC Ad Hoc Committee touched on the issue of commission expertise in its discussion of the problem of cross-subsidization. The Committee stated that regulators would have to understand nonutility accounting methods and the types of costs incurred or resources used by any unregulated subsidiaries. It was also noted that regulators would have to develop new accounting procedures to deal with cross-subsidization.[61]

With respect to the additional burden on the state utility commission staff of monitoring transactions between the utility and its subsidiaries, the NARUC report observed that staff may have to devote substantial time to this task. This could represent a significant cost to the commission, as well as a further strain on limited commission resources.[62]

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[61] National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification, p. 21. The Edison Electric Institute study also mentioned the potential problem of commission expertise. With respect to a suggestion that a utility planning to diversify present its plans to the state utility commission for prior approval, the EEI stated that such a suggestion "would require state commissions to make decisions in areas where they have no special interest or expertise. Edison Electric Institute, Electric Utility Diversification, 1:73.

[62] Ibid., pp. 27-28.

CHAPTER 3

SURVEY RESULTS

Lack of current information about actual commission positions and policies on the issues discussed in chapter 2 prompted an NRRI survey to develop this information. The survey instrument and detailed raw data of the survey are in appendix B. A summary and discussion of the results are presented in this chapter.

The survey questions were focussed on state commission policies in the following areas: the establishment and divestiture of electric utility subsidiaries, the transactions between electric utilities and their subsidiaries, the allocation of joint and common administrative costs, and the allocation of profits acquired by the utility from its subsidiaries. The authors requested that the survey questionnaire be answered by the senior policy level commission staff member who is most familiar with the commission's regulatory treatment of electric utility subsidiaries and affiliates. The reader should keep in mind that responses to the survey would not necessarily reflect the views of a commissioners on the topic of diversification. Also the NRRI survey was not meant as a survey of commission policies toward holding companies, except where transactions occur between an electric utility and company affiliated by means of a holding company. The NRRI sent survey instruments to forty-nine of the fifty state commisions and to the District of Columbia Public Service Commission in February 1985.[1] Forty commissions responded. With one exception, the NRRI received responses to the survey instrument by May 31, 1985. That commission sent in its survey answers in July 1985.

The Number and Types of Subsidiaries

There has been recent activity in the establishment of subsidiaries in the electric utility industry. Not only are there numerous electric utility subsidiaries, but there are also many types, as shown in table 3-1.

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[1]The survey instrument was not sent to the Nebraska Public Utilities Commission because it does not regulate electric utilities.

TABLE 3-1

THE NUMBER OF ELECTRIC UTILITY
SUBSIDIARIES AND AFFILIATES BY TYPE

State	Fuel Exploration and Development	Real Estate	Telephone-Telecommunications	Fuel Transportation-Transloading	Commercial Paper Sales
AL	1	1	0	0	0
AZ	4	1	4	0	2
AR	1	0	0	1	0
CA	8	4	1	0	2
CO	1	1	0	0	0
CT	0	2	0	0	0
DE	1	0	0	0	0
DC	0	0	0	0	0
FL	9	4	0	10	0
ID	2	0	1	0	0
IL	6	1	0	0	0
KS	1	0	0	0	0
ME	0	0	0	0	0
MI	2	1	0	1	0
MN	0	0	0	0	0
MO	0	1	0	0	0
NV	1	1	0	0	0
NH	0	1	0	0	0
NJ	3	1	0	2	1
NM	1	2	0	0	0
NY	1	6	0	0	3
ND	3	0	0	0	0
OH	4	3	0	0	1
OR	2	1	0	1	0
PA	8	9	0	1	0
SC	1	2	0	0	2
SD	10	4	0	2	0
TX	4	1	0	4[b]	0
UT	0	0	0	0	0
WA	29	5	31	3	0
WV	1	0	0	0	0
Total	104	52	37	25	11

(Continued on next page)

TABLE 3-1 -Continued

State	Investment-Stock/Other Property	Cogeneration	Project Management/Engineering/Consulting Services	Energy Conservation Services	Other	Total
AL	0	0	0	0	1	3
AZ	3	0	2	1	13	30
AR	0	1	2	0	1	6
CA	0	1	0	2	3[a]	21
CO	0	0	0	0	0	2
CT	0	0	0	0	0	2
DE	0	0	0	0	1	2
DC	1	0	0	0	1	2
FL	2	0	0	0	10	34
ID	0	1	0	0	0	5
IL	0	0	0	0	5	12
KS	0	0	0	0	0	1
ME	0	0	0	0	2	2
MI	0	0	1	0	2	7
MN	0	0	0	0	1	1
MO	0	0	0	0	0	1
NV	0	0	0	0	2	4
NH	0	0	1	0	1	3
NJ	0	1	0	0	1	9
NM	0	0	0	0	3	6
NY	0	2	0	2	2	16
ND	0	0	0	0	0	3
OH	0	0	0	0	15	23
OR	0	0	0	1	4	9
PA	0	0	0	0	1	19
SC	0	0	0	0	1	6
SD	0	0	0	0	0	16
TX	0	1	0	0	0	6
UT	0	1	0	0	0	1
WA	4	2	2	0	15	95
WV	0	0	0	0	3	4
Total	10	10	8	6	88	351

Source: The survey response raw data contained in appendix A: responses to survey questions 4 and 5.

a. In addition the Pacific Gas & Electric Company has numerous gas-related subsidiaries that are not included in this total.

b. These four Texas fuel transportation-transloading affiliates are the same affiliates as the four Texas fuel exploration and development affiliates.

Yet certain utilities and certain jurisdictions are more likely to have subsidiaries than others. The NRRI wanted to know how many and what types of subsidiaries did each state utility commission face. In table 3-1, the authors show the number of electric utility subsidiaries, by type and by state, for those states responding to those particular questions.

The most common type of electric utility subsidiary is the fuel exploration and development subsidiary. The prevalence of fuel exploration and development subsidiaries is not unexpected because of the opportunities that such subsidiaries offer. One staff member at the Washington Utilities and Transportation Commission, reported twenty-nine fuel exploration and development subsidiaries under the commission's jurisdiction.

The next most common type of subsidiary, according to the survey responses, is the real estate subsidiary. Twenty-one commission staffs reported having fifty-two real estate subsidiaries owned (at least in part) by the electric utilities in their jurisdictions. Utilities set up real estate subsidiaries to acquire, to hold, and, occasionally, to sell property held for future use. Setting up a real estate subsidiary can be part of a strategy for obtaining property at least cost, and, perhaps, avoiding local opposition to the sale of the land.[2] In other cases, a real estate subsidiary may be involved in activities that are not directly utility-related. For example, the Ohio Public Utilities Commission staff reported that the Cleveland Electric Illuminating Company owns CEICO Company, a subsidiary which in turn owns nonutility land, and that the Dayton Power and Light Company (DP&L) has a wholly-owned subsidiary that owns DP&L's headquarters building.

The third most common type of electric utility subsidiary is the telephone-telecommunications subsidiary. The commission staffs reported thirty-seven telephone or telecommunications entities as subsidiaries of electric utilities. However, the telephone-telecommunications subsidiaries

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[2]For example, the New York Public Service Commission staff noted: "In most [New York] cases the subsidiaries were initially established by the utility as a means of obtaining land without the seller knowing that a utility was 'interested' in the property."

are spread across fewer jurisdictions. Only three jurisdictions reported knowing about telephone-telecommunications subsidiaries. The Arizona Commerce Commission staff noted that one utility company subsidiaries outside the state of Arizona, beyond the Commission's jurisdiction. The California Public Utilities staff reported that the parent holding company of Pacific Power & Light Company owns a telephone company. Thirty-one of the thirty-seven telephone-telecommunications subsidiaries are reported by the Washington Utilities and Transportation Commission (WUTC). All thirty-one are subsidiaries or affiliates of the Pacific Power & Light Company.

The fourth most common type of electric utility subsidiary is the fuel transportation-transloading subsidiary. Nine commission staffs reported having twenty-five such subsidiaries within their jurisdiction. Ten of the fuel transportation-transloading subsidiaries are reported by the Florida Public Service Commission staff. These subsidiaries are involved in the transportation and transloading of coal for the Florida Power Corporation and the Tampa Electric Company. The four Texas fuel transportation-transloading affiliates listed in table 3-1 are the same affiliates as the four Texas fuel exploration and development affiliates. Electric utility fuel transportation-transloading subsidiaries are engaged in utility-related activities that have at least the theoretical potential of resulting in savings in utility operating costs.

Six commission staffs reported that eleven electric utility subsidiaries engage in commercial paper sales. It is worth noting that several of these subsidiaries have been established offshore, presumably to take advantage of the favorable tax treatment available from financing through an offshore entity. Several of these offshore entities borrow funds primarily from outside the United States. These subsidiaries sometimes also finance the nonutility related activities of a utility's subsidiaries.

The next most common types of subsidiaries are the investment subsidiary and cogeneration subsidiary. Four commission staffs reported that their electric utilities have ten subsidiaries that engage in the non-utility related activity of investing a utility's retained earnings in stocks and other property of other companies. In other words, these investment subsidiaries are set up for the specific purpose of allowing the utility to diversify into nonutility areas. Eight commissions reported that their electric utilities set up ten subsidiaries that engage in co-generation, a utility related activity.

The survey responses also show that some electric utilities are setting up project management/engineering/consulting services, and energy conservation service entities. Five commission staffs reported a total of eight project management/engineering/consulting service subsidiaries in their jurisdictions; and four commission staffs reported a total of six of energy conservation subsidiaries in their jurisdictions. The establishment such subsidiaries shows that electric utilities are willing to capitalize on the existing expertise that they have developed by offering services, ancillary to energy related activities, to others.

The commission staffs also responded that there are eighty-eight other subsidiaries established by electric utilities that do not fit into any of the categories just mentioned. Included in these other subsidiaries are four appliance-sales-leasing-service subsidiaries, four computer software sales subsidiaries, four customer billing-collection services subsidiaries, four solar-renewable product sales subsidiaries, three short line railroad subsidiaries, several affiliated electric or gas or service companies, and three subsidiaries for constructing power plants. Two unique activities undertaken by electric utility subsidiaries are reported by the Washington Utilities and Transportation Commission staff. One subsidiary of the Pacific Power & Light Company is engaged in developing a holographic overhead display system for commercial airlines; another is engaged in developing a computer-based identification system which scans and registers the unique blood vessel patterns on the retina of the eye. In both of these cases the utility's partial ownership interest is held indirectly through Pacific Telecom, Inc., a telephone holding company in which the Pacific Power & Light Company holds a majority interest. The detailed reponses of the commission staffs to the NRRI survey on the types of electric utility subsidiaries can be found in appendix A, questions 4 and 5.

As can be seen in table 3-1, the established electric utility subsidiaries are not evenly distributed across the states. To some extent one would expect this to be the case, because some states are simply larger or have a greater number of electric utilities. However, it appears that the electric utilities in some states are simply more interested in establishing or acquiring subsidiaries or that certain state commissions are more willing to allow their establishment. For example, the South Dakota Public Utilities Commission staff reported 16 subsidiaries, the Arizona Commerce Commission staff reported 26 subsidiaries, the Florida Public Service Commission staff reported 34 subsidiaries, and the Washington Utilities and Transportation Commission staff reported 95 subsidiaries. At least in one instance, a state commission (the Washington Utilities and Transportation Commission) reported a greater number of subsidiaries than do commissions in other surrounding states, served by the same multistate electric utility.

Commissions and the Establishment of Subsidiaries

In order to learn more about how state commissions actually regulate electric utility subsidiaries, the NRRI survey incorporated a variety of questions about state commission authority and procedures. This section of the chapter discusses regulatory involvement at the outset of the diversification process by examining commission authority over and views on the establishment of electric utility subsidiaries, as well as any conditions that a commission may attach to its approval of a subsidiary's establishment.

Commission Authority over the Establishment of Subsidiaries

Staffs of the state commissions were asked whether their commission has the authority to approve or disapprove the establishment by electric utilities of subsidiaries. The survey responses show that generally their commissions do not have such authority. This runs counter to the view held by some in the literature discussed in chapter 2. Of the thirty-nine commissions responding to this survey question, twenty-seven commission staffs said that their commissions have no such authority, and two commission staffs said that they were uncertain. Only ten staffs said that their commissions did have such authority.

Of the twenty-seven commission staffs that stated that their commissions do not have authority to approve or disapprove the establishment of electric utility subsidiaries, three commission staffs gave important caveats to their answers. The Colorado Public Utilities Commission staff noted that in those cases where a subsidiary or affiliate is also a utility, it would be subject to state regulation. The Pennsylvania Commission staff cautioned that, while it does not have direct authority over the establishment of subsidiaries, it does have the authority to approve or disapprove securities issuances that may be necessary for acquiring or financing the subsidiary. The New Mexico Commission staff asserted that it does have certain specified authority to examine the books and records of the subsidiaries and affiliates.

The Michigan Public Service Commission staff was uncertain about the Commission's authority, because it has never been fully tested in the courts. The Montana staff noted its Commission's authority is currently being tested in the courts, and legislation has been introduced to clarify and clearly establish the authority of the Commission over a utility's subsidiaries.

Of the ten commission staffs responding that their commissions have such authority, three mentioned conditions which limit that authority. The Massachusetts Department of Public Utilities staff noted that for all of the electric companies in a holding company system, the holding company can form subsidiaries at will, subject to any Securities and Exchange Commission requirement. The Department exercises its jurisdiction over the subsidiary to regulate the transactions between it and affiliated companies. If the utility is not a holding company but rather an independent operating utility company, then it is required to get Department approval before establishing subsidiaries or affiliates.

The New York Commission requires its approval for the establishment of a subsidiary only if the utility uses its revenue to directly provide funds for or guarantee the debt of the subsidiary. The Washington Commission requires approval if the utility's assets, used in providing utility services, are being transferred to the new subsidiary. In addition, if a utility is restructured so that its voting common stock would be exchanged for all the stock of a new holding company, commission approval would be required if any new stock were issued by the utility or any of its assets were transferred to the holding company.

Of the ten commissions having authority to approve or disapprove the establishment of electric utility subsidiaries, six commission staffs reported receiving utility requests to set up subsidiaries. Five of these commission staffs report considering 27 requests. Twenty-five requests were approved; one was disapproved; and one is still pending. An additional 4 requests that were initially made were subsequently withdrawn. The sixth staff was unable to quantify how many requests for subsidiaries that it has received.

Reasons for Establishing Subsidiaries

The NRRI next asked the staffs of those commissions that have authority over the establishment of subsidiaries what reasons the utilities gave for wanting to establish separate subsidiaries. In several of the states the reasons given were similar to many of the theoretical benefits of diversification discussed in chapter 2. The Illinois Commission staff, for example, stated that the reasons given included to allow the utility to expand into businesses ancillary to its utility services, and to establish foreign markets. The New Hampshire Commission staff responded that the reasons given were to separate areas of responsibility, to identify responsibilities by task organization, to separate regulated from unregulated enterprises, and to improve the utility's technical expertise. The New York Department of Public Service reported that the reasons electric utilities gave for wanting to establish separate subsidiaries were to protect the ratepayer, to give the proper incentives to the management of the subsidiary to be productive, and to help to ensure the development of cost-effective energy resources in the state.[3] The Oregon Commission staff stated that utilities claim that in some way costs will be reduced for ratepayers if subsidiaries are established.[4]

In some other instances, state commission staffs reported that the reasons given for establishing a subsidiary were very specific. The Illinois and Massachusetts Commissions' staffs reported that utilities wanted to set up subsidiaries to finance nuclear fuel requirements.

Have the Theoretical Benefits of Subsidiaries Been Realized?

Most staffs from commissions with authority over the establishment of electric utility subsidiaries indicated that their commissions do not formally evaluate whether and to what extent the potential advantages and disadvantages of subsidiaries have been realized. A few commission staffs did indicate, however, that they do evaluate the advantages and disadvantages of having a subsidiary during rate case proceedings. The Illinois staff, for example, reported that the impact of electric utility subsidiaries on ratepayers is reviewed during rate case proceedings. The New Hampshire staff noted that, while the Commission does not formally evaluate whether potential advantages and disadvantages have been realized, issues raised in rate cases have supported the proposition that the existence of subsidiaries has been generally favorable. The Massachusetts staff stated that the operation of a subsidiary can be reviewed in any rate case and that the Commission had approved the financing necessary to establish the Boston Edison Company's BEC Fuel Company, because it would result in

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[3]Utilities in New York invested in uranium ventures to secure fuel at reasonable prices. The New York staff also reported that the Orange & Rockland Company justified establishing its real estate subsidiary on the grounds that it would enhance the real estate development in its area, thereby increasing the load on its system which would reduce fixed costs caused by other ratepayers.

[4]The reasons given by utilities in Oregon to establish a subsidiary were to develop cogeneration, small power, and geothermal power production facilities, and to enter other areas related to energy development and conservation.

savings to the ratepayer. The Missouri staff also indicated that it evaluates subsidiaries only in the context of rate proceedings.

The Idaho staff, on the other hand, indicated that it does review existing utility affiliates that have a direct bearing on utility operations. In such a review the Commission may ignore the separate corporate identity of the affiliate. The New York Department of Public Service staff commented that, there has been no formal evaluation of the performance of electric utility subsidiaries or how they affect ratepayers or stockholders. On the whole, state commissions do not appear to be very active in evaluating whether or not the theoretical advantages and disadvantages of subsidiaries establishted under their authority have been realized.

Commission Procedures and Considerations

Next the staffs of commissions with authority over the establishment of subsidiaries were asked to comment on what procedures are used by their commissions in approving or disapproving the establishment of subsidiaries. In some commissions a separate hearing is devoted to the establishment of the subsidiary; others handle the request as a part of a securities issuance proceeding; a few commissions have the power to utilize either proceeding.

Several of the commission staffs indicated that their commissions do consider the appropriateness of an electric utility having subsidiaries. The Illinois staff, for example, reported that the Commission is required to consider the appropriateness of subsidiaries pursuant to the Illinois Public Utilities Act. The Maine staff responded that the Commission determines the appropriateness of a subsidiary by determining whether the subsidiary is in the best interest of the utility's ratepayers. Both the New Hampshire and New York staffs indicated that their Commissions consider the appropriateness of the electric utility having subsidiaries and the type of business the subsidiary would be engaged in. In New York, the Commission considers whether the business that the proposed subsidiary would be engaged in is related to operation of the electric utility or maintaining better load characteristics. The focus of the Commission's inquiry is on the extent of the financial burden that would be placed on the utility because of the formation and operation of the subsidiary.

Few commission staffs indicated that their commissions periodically reassess the appropriateness of subsidiaries after an initial determination of appropriateness has been made when the subsidiary is established. However, both the Illinois and the New Hampshire staffs stated that the appropriateness of their utilities' subsidiaries is reviewed during rate cases. In addition, in New Hampshire the subsidiary is subject to periodic review at any time. The Oregon Commission staff reported that they are currently studying the subsidiary/affiliate structure of all their major utilities. The staffs of the Arkansas, Illinois, Oregon, and Utah Commissions noted that the methods used by their commissions to determine the appropriateness of subsidiaries are now under review.

Most of the commission staffs responded that they did assess the potential risk to ratepayers of the proposed subsidiary. The Illinois and New Hampshire staffs indicated that they used a hearing process to assess the potential risks to ratepayers. The New York staff indicated that the risk to ratepayers is regularly examined on a case-by-case basis. The staffs of only two of the commissions with authority over the establishment of subsidiaries (Oregon and Utah) indicated that their commissions had no established procedures to assess the potential risk to ratepayers of a proposed subsidiary.

The several commissions look at different types of risk that a subsidiary may pose to ratepayers. The Illinois staff reported that the proper insulation of utility operation from nonutility business is the major type of risk examined. Proper insulation occurs by eliminating cross-subsidization, developing methodologies for cost allocations and setting transfer prices, and maintaining separate capital structures. The staff of the New York Commission reported that the commission is concerned about the risk of cross-subsidization and has instituted safeguards to help ensure that cross-subsidization will not occur. The staff of the Michigan Commission reported that its commission is concerned with whether the subsidiary, if it fails, endangers the continuation of safe, reliable, and adequate electric service. The New Hampshire Commission looks at the likelihood of success of the venture, and the relative benefits and costs to the ratepayer. The staffs of both the Hawaii and Illinois Commissions indicated that those commissions would look closely at financial risks created by the subsidiary. This would be done by examining the extent of financing being provided by the utility and by determining that this financial exposure would not be harmful to ratepayers.

The Illinois staff stated that the Commission may examine or determine what other alternatives are available to the utility, evaluate the market conditions, and determine whether the subsidiary would be obtaining its own financing. The Illinois Commission may also examine the type of business the subsidiary would be involved in to see whether the business is related to utility operations.

The New Hampshire Commission weighs all advantages and disadvantages of establishing a subsidiary against the current utility operations. Usually, the proposed subsidiary would provide service to more than one customer. The Commission considers the cost savings resulting from the consolidation of the utility with a subsidiary. The cost of a consolidated approach to fuel procurement, for instance, is weighed against the cost of the utility's continued use of internal assets to procure fuel.

Commission Oversight of the Financing of Subsidiaries

Most of the staffs of commissions with authority over subsidiary or affiliate establishment indicate that the source of a utility's financing for its subsidiaries is a utility's retained earnings. One commission staff reported an investment in a subsidiary or affiliate that was secured or guaranteed by a utility's assets; the Missouri Commission staff cited the Kansas Power & Light Company's arrangement to borrow up to $70 million for the purchase of The Gas Service Company's stock under its tender offer. However, this may be an example more of a corporate takeover than an establishment of a new subsidiary. The staff of another commission, Illinois, noted that the investments in electric utility subsidiaries are generally secured by common and/or preferred stocks.

The New York Commission staff reported that, if a subsidiary requires the guarantee of the parent utility to issue its own debt securities, the utility must petition and obtain the Commission's approval for such action.

In any event, the source of the subsidiaries' funding is not securities issued by the utility. The source is the utility's retained earnings. New York law does not permit issuances of utility securities for nonutility purposes. The Washington Commission staff reported no guarantee of a subsidiary's or an affiliate's securities is permitted without prior Commission approval.

A few commission staffs reported having overseen the obtaining by electric utilities of investments and loans to finance the establishment of subsidiaries. For example, the Illinois Commission has a general authority to approve a utility's issuance of stocks and bonds, notes, and other evidences of indebtedness payable for more than 12 months. The New Hampshire staff noted that financing approval was required by the Public Service Company of New Hampshire to set up its PSNH Overseas Finance, N.V.

Special Accounting and Reporting Requirements

Several of the staffs of commissions with authority over utility subsidiary establishment also report that they have the authority to impose special accounting and reporting requirements on the utility. For example, the Oregon staff reported that the Commission expects the utility to carefully segregate and account for all expenses and revenues related to its subsidiaries and affiliates. The Utah staff reported that the utility would be required to account for the subsidiary according to a chart of accounts. The Massachusetts staff reported that the Department may impose accounting requirements and require reports in addition to the annual reports.

The New York staff emphasized that prior to any further utility investment in a subsidiary, Commission approval must be sought. The Commission can limit the subsidiary's activities to those specified in the company's petition.

The Illinois staff claimed the broadest authority of a commission to condition its approval of the establishment of a subsidiary: the staff reported that that commission may condition its approval of the establishment of a subsidiary <u>in any manner</u> depending on the individual circumstances of the proceeding. The staff also notes that under section 12 of the Illinois Public Utilities Act:

> the Commission may require every public utility engaged in directly or indirectly in any other than a public utility business, as defined by law to keep separately in like manner and form the accounts of all such other business, and the Commission may provide for the examination and inspection of the books, accounts, papers and records of such other business, in so far as may be necessary to enhance any provision of this Act. The Commission shall have the power to inquire as to and prescribe the apportionment of capitalization, earnings, debts and expenses fairly and justly to be awarded to or borne by the ownership, operation, management or control of such public utility as distinguished from such other business.[5]

Comprehensive Commission Strategies

The staffs of most state commissions with authority over subsidiary establishment reported that comprehensive strategies for dealing with electric utility establishment of subsidiaries are not now being formulated. However, there are a few exceptions. The Illinois staff reported that its Commission has begun a study to develop such a comprehensive strategy. The staff of the District of Columbia Commission noted that a strategy may be developed for the next rate case. The Arkansas Commission staff noted that legislation has been proposed for dealing with the establishment of subsidiaries.

Commission Policies and Practices for Regulating the Utility-Subsidiary Relationship

Having examined the involvement of state utility commissions at the beginning of the diversification process with the establishment of subsidiaries and/or affiliates, the discussion turns now to state commission regulation of the ongoing relationship between electric utilities and their

[5]Illinois Public Utilities Act, section 12.

subsidiaries and/or affiliates. This section outlines a variety of policies and procedures that state commissions told the NRRI that they were employing. While the previous section was concerned mainly with the responses of the several commissions asserting authority over subsidiary establishment, this section analyzes the answers by the entire sample of commissions responding to the survey, regardless of whether or not they have authority over subsidiary establishment.

Access to Books and Records

Nearly all commission staffs responded when asked whether their commissions have authority to gain access to the books and records of electric utility subsidiaries and affiliates or to the records of the holding company parent of an electric utility, whether company officials have been cooperative in providing records, and what types of problems their commissions have encountered in reviewing corporate records. The staffs of several commissions, albeit a minority, stated that they do not have authority to gain access to a subsidiary's books. However, most of these staffs report that they can gain access to the relevant portions of the books and records. For example, the Arizona staff reported that its Commission could obtain records through its subpoena powers if company officials were uncooperative. According to the staff, the Commission has indirect authority to gain access to a subsidiary's accounts, because the utility as a stockholder in its subsidiary has access to the accounts. The California staff indicated that the Commission could disallow, for ratemaking purposes, any costs which cannot be verified by direct examination. The staffs of the Colorado and West Virginia Commissions also noted that they can disallow costs from ratemaking if the utility refuses to allow such access. The staff of the Colorado Commission engages in "legal discovery" in order to obtain information on subsidiaries. The staff of the Pennsylvania Commission has been successful in obtaining the necessary information by directing the jurisdictional utility to provide it as probative evidence for setting rates. If the utility fails to provide the information, there could be a finding that the utility's burden of proof has not been satisfied and a revenue adjustment would normally follow.

Moreover, there are provisions in the Pennsylvania Public Utility Code that require a jurisdictional utility to provide records or data of an affiliate as a condition of Commission approval of utility contracts with its affiliates.[6]

The source of the commission authority can be quite diverse. One commission staff cited both an affiliate transaction statute and a statute providing the commission authority to allow or disallow the establishment of subsidiaries as their source of authority to gain access to books and records of subsidiaries. The Hawaii Commission staff stated that the Commission has statutory authority to examine all transactions, and, if a utility seeks to establish a non-regulated subsidiary, the Commission can make its access to the subsidiary's books a condition of approval to establish the subsidiary.

Several commission staffs cited affiliate transaction statutes as their source of authority to gain access to subsidiary books and records. The staff of the Illinois Commission cited section 8a(2) of the Illinois Public Utilities Act as the source of the Commission's very broad authority to gain access to a subsidiary's books. Section 8a(2) states

> The Commission shall have jurisdiction over affiliated interests having transactions, other than ownership of stock and receipt of dividends thereon, with public utilities under the jurisdiction of the Commission, to the extent of access to all accounts and records of such affiliated interests relating to such transactions, including access to accounts and records of joint or general expenses, any portion of which may be applicable to such transactions; and to the extent of authority to require such reports with respect to such transactions to be submitted by such affiliated interests, as the Commission may prescribe.

The Kansas Commission staff cited a similar statute as their source of authority, although there has been only a limited opportunity to use the statute. The Texas and Massachusetts staffs stated that their Commissions also have statutory authority to gain access to the books of subsidiaries to the extent that the records deal with transactions with regulated operating companies. In Texas the authority to gain access to books includes

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[6] 66 Pa.C.S. §2101-07.

all accounts and records that would relate to the allocation of joint costs. The staff of the Washington Commission asserted that the state has a strong affiliated interest statute that requires the utility to justify the reasonableness of any payment to an affiliated interest on the basis of the cost the affiliate incurs to provide the goods or services.

A few staffs reported that their commissions have the authority to gain access to the books and records of the subsidiaries, but that the source of their authority is something other than their authorization of establishment of subsidiaries or affiliated transaction statutes. According to its staff, the Minnesota Commission has the statutory authority to investigate an affiliate's costs, if necessary, to approve a contract between the utility and its subsidiary. The Nevada Commission relies on the results of audits performed by independent CPAs for information on holding companies. Nonregulated affiliates are checked on a specific transaction basis only. The staff of the New Jersey Commission noted that in the case of a holding company a copy of the annual report with the United States Securities and Exchange Commission can be filed with the New Jersey Commission in place of the utility's usual annual report to the New Jersey Commission. In addition, the New Jersey Commission must approve a service contract between a holding company's service company and its operating companies to provide service to the operating companies. Each year, as long as the service contract is in force, the service company must file a complete statement with the Commission showing separately the charge for service rendered and the basis for calculating that charge. The service company also must keep its books and records available for inspection at all times and, on request of the Commission, furnish additional information on the costs of services rendered to the operating companies.

Whether or not the commissions have authority to gain access to the books and records of subsidiaries or to the records of the holding company parent, most staffs of the commissions reported that company officials have been cooperative in providing records and that the commissions have encountered few, if any, problems in reviewing the corporate records. There are a few notable exceptions, however. The staff of the California Commission characterizes the company managements as being reluctantly cooperative in providing books and records. The biggest problem that the California staff cited is the amount of time that it takes for the companies to respond to data requests or requests to examine records. The staff of the Florida Commission notes that, while company officials have been generally cooperative in supplying records, one of their utilities has an affiliate that is involved in partnerships but which does not have a controlling interest in those partnerships; the other partners are somewhat hesitant to allow the commission to have access to the partnership books. The staff of the Massachusetts Department stated that company officials are generally cooperative though it is sometimes difficult to extract detailed information from the records. The staff of the New York Commission reported that the one problem that the Commission has encountered is poor recordkeeping on the part of the subsidiary.

Commission Authority to Order Divestiture of a Subsidiary

Once a subsidiary is established, the NRRI survey shows that most commissions do not believe they have authority to order the divestiture of that subsidiary from the electric utility. Only three staffs (Maine, New Hampshire, and Utah) answered with a definite affirmative that their commissions do have the authority to order divestiture. The staffs of several commissions are uncertain about whether or not they have such authority. The staff of the Massachusetts Department, for instance, notes that such divestiture has never occurred but that the Department probably does have the authority to order divestiture if the subsidiary was established by a utility operating company and not a holding company. Similarly, a staff member from the North Carolina Commission stated that he believes that the Commission could revoke an electric utility's franchise if the utility refused to divest itself of a subsidiary after the Commission had determined that the operations of the subsidiary were preventing the utility from performing its franchise duties satisfactorily. The staff of the Pennsylvania Commission commented that there is no express authority for the Commission to order divestiture; however, if the Commission does have the implied authority to order divestiture, it would occur under circumstances where the continued financial health of the utility would be threatened if the utility did not divest. The staff of the Ohio Commission contends that while the Commission has never considered the issue of divestiture, the Commission has broad statutory authority to carry out the purposes of the state's public utility statutes.

Staff Time and Expense

The NRRI survey shows that most commissions do not devote a great deal of time or expense to the regulation of electric utility subsidiaries and only rarely has the hiring of new staff been required expressly for the purpose. Typical responses are those of the Idaho and Alabama staffs. The Idaho staff stated that the incremental cost devoted to regulating electric utility subsidiaries is inseparable and minimal. A review of subsidiaries is conducted as an integral part of the general review of a regulated utility's operations. The Alabama staff devotes little time to subsidiary regulation because of limited resources. Any new staff that is hired is assigned to other areas considered more important.

The staffs of a few commissions, however, reported a significant amount of staff time devoted to the regulation of subsidiaries. The Illinois staff, for example, reported that, while no specific information is kept on the time or expense devoted to regulation of subsidiaries, substantial staff time is devoted to regulating affiliate interest transactions. The Oregon staff reported that one man-year per year of staff time is spent on this issue. The California staff noted that since the review of affiliate transactions has been routine for many years, it is difficult to assign a percentage of staff time to that procedure. A current estimate would be 3-man years per year, one for each major electric utility. The Commission anticipates that additional staff will be required in the future as electric utilities further diversify.

The Washington Commission reported that its staff for handling affiliate transactions has been in place since the 1940s. Their experience is that dealing with affiliated interests in the context of a utility rate request is a normal part of staff duties. They estimate that dealing with affiliated interest costs, during a rate case, can constitute up to 20 percent of the staff's time in a case.

Commission Practices and Safeguards

This subsection deals with periodic commission reviews of the business relationships between utilities and their subsidiaries, commission accounting requirements, regulatory practices concerning transfer pricing, regulatory practices that deal with the allocation of joint and common costs, and commission policies on the allocation between ratepayers and stockholders of any earnings a utility may receive from either the operation or sale of its subsidiary.

Periodic Reviews and Accounting Requirements

Most staffs (thirty of the forty) reported that their commissions do review the business relationships between electric utilities and their subsidiaries on a periodic basis. The review can take many forms. Some of the commission staffs stated that a periodic review of the business relationships occurs during rate hearings. These staffs include those of the Arizona, Arkansas, California, Connecticut, Idaho, Illinois, Kansas, Kentucky, Maine, Massachusetts, Missouri, Nevada, New Hampshire, New York, North Dakota, Ohio, Oregon, Pennsylvania, Texas, and Washington Commissions.

Several of these commissions also review the business relationships between electric utilities and their subsidiaries in other contexts. The California Commission staff, for example, reported that it may conduct reviews on other occasions besides rate hearings, if appropriate. The Illinois Commission staff noted that in addition to the rate case review, that most contracts and arrangements made between a utility and an affiliated interest must be filed and consented to by the Commission. The staff of the New York Commission also conducts reviews when utilities request authority to increase the investment in a subsidiary or to form a new subsidiary. In Pennsylvania, the utility's relations with affiliated interests are also reviewed when the utility makes affiliated interest filings.

The staff of the Nevada Commission noted that intracompany sales and common cost allocations are audited prior to general rate case proceedings. Also, the commission's Five- and Twenty-Year Resource Plan hearings consider the impact of subsidiaries' activities on the cost associated with a utility's operations.

In Ohio a utility's relationships with its subsidiaries are reviewed in at least two contexts other than rate case investigations. The review can occur during annual fuel procurement audits and commission-initiated management audits. The New Hampshire, North Dakota, and Texas Commissions also review the relationships between a utility and its subsidiaries during audits. The New Hampshire Commission audits are conducted by the staff. For the Texas Commission these audits are operational audits, performed on fuel affiliates and used in fuel proceedings. In North Dakota, the Commission makes its reviews during a fuel adjustment audit.

Similarly, four other staffs reported that their commissions review the business relationships between electric utilities and their subsidiaries or affiliates during either audits and/or fuel adjustment proceedings. These commissions are Colorado, Michigan, South Carolina, and West Virginia. The Colorado staff noted that whenever the utilities are audited, the impact of the subsidiaries on the utilities are also audited. In Michigan, the Commission reviews the relationship between a utility and its subsidiary when doing compliance audits and/or rate case audits. In South Carolina, the Commission reviews the relationship between a utility and its subsidiary at its semi-annual fuel hearings. The West Virginia Commission reviews service company charges and captive coal transactions in the context of its annual or semi-annual fuel review cases.

A few of the commission staffs reported that the business relationships between electric utilities and their subsidiaries or affiliates are reviewed on a periodic basis by some means other than rate cases, audits, and fuel adjustment proceedings. The Florida staff, for example, responded that its reviews are limited primarily to contract compliance. The North Carolina staff stated that the Commission requires the utilities to report annually the value and type of all services rendered to the utility by its subsidiaries.

Two of the commission staffs responded that their review processes led to utilities selling off their subsidiaries. The South Carolina staff said that their commission once did an extensive review of the Duke Power Company's relationship to its three affiliated coal mining operations. After that review, Duke Power Company disposed of two of these operations. The West Virginia Commission staff reported that when the Appalachian Power Company owned coal producing subsidiaries, the Commission adjusted the prices to market prices if these were higher than market prices. The Appalachian Power Company sold these subsidiaries in 1984.

The Ohio staff stated that the subsidiary relationships with Ohio utilities, to date, can be classified in three categories. First, some of the subsidiary companies engage in activities that involve too few dollars to materially affect utility costs or services. Second, some subsidiary activities are vertically integrated and can be treated as fully integrated activities for ratemaking purposes, obviating the need for any special concern. Third, some of the subsidiary activities are convenience arrangements (paper subsidiaries) established by the utilities as separate accounting or reporting entities for financing purposes. These convenience arrangements can be sorted out in rate cases.

Six staffs reported that their commissions do not periodically review the business relationships between electric utilities subsidiaries or affiliates. These commissions are the Delaware, District of Columbia, Georgia, Minnesota, New Jersey, and South Dakota Commissions.

In order to help isolate transfer pricing abuses and to prevent cross-subsidies between a utility and its subsidiaries, most state commissions require that the utility, which must keep its accounts according to either the FERC or NARUC Uniform System of Accounts (USOA), keep the costs of the subsidiary separate from those of the utility. Generally the subsidiary's costs are separated by using "below the line accounts." Beyond this, most commissions either do not regulate the accounts of the subsidiary, or merely require that the subsidiary keep its books according to generally accepted accounting procedures.

Transfer Pricing

Most commissions attempt to isolate and control the prices of goods and services transferred from an electric utility's subsidiaries to the utility. Several methods of controlling transfer pricing abuse were cited by the staffs as being used by the state commissions.

Some state commission staffs cited a "reasonableness" or a "prudence" test as the method used to control transfer pricing abuse. The Nevada staff, for example, indicated that its Commission considers the prudence of intracompany transaction and the reasonableness of the prices or costs.

The prudence or reasonableness test is a flexible standard for controlling transfer pricing. A market price comparison is a fairly common measure of prudence or reasonableness. The Alabama Commission uses a market test as a standard of reasonablenesss. The Alabama staff stated that the Commission determines the reasonableness of pricing of goods and services transferred between utilities and subsidiaries by comparing the prices charged by a subsidiary or affiliate to those charged by other suppliers. The Commission also regulates the purchases or sales between an electric utility and its subsidiaries to the extent of determining its prudence. The Ohio Commission staff responded that the Commission does not directly control or regulate transactions between a utility and its subsidiaries, but that inclusion of the cost of a transaction in rates is authorized only after scrutiny and a determination of reasonableness. If an expenditure is found to be unreasonable, an adjustment is made to exclude the unreasonable portion of the expense from the rate case. As a part of its investigation of any rate application, the staff reviews the expenditures attributed to services or purchases from an affiliate company for reasonableness.

Other staffs report similar approaches. The Kansas Commission, for example, does so by obtaining the costs of similar goods or products supplied or available within a utility's operating boundaries and then comparing the costs of goods and services supplied to a utility by its subsidiaries with the market price of comparable goods and services. In Colorado, a utility cannot purchase fuel from its own subsidiary above the spot market price.

The Illinois Commission compares the costs of goods and services supplied to the utility by its subsidiary with market prices at the time that the utility files for approval of the affiliated interest transaction (an affiliated interest transaction cannot take place without prior Commission approval), and also during rate proceedings. The Commission does not require a utility to purchase goods or services at the market price if the market price exceeds that offered by the affiliate or subsidiary. The Illinois Commission also does not disapprove or disallow payments (expenditures) made for purchases from an affiliated interest solely because the payment results in a rate of return for the affiliate that is in excess of that allowed the utility.

The Arizona Commission determines in rate cases whether a utility paid too much for a good or service from one of its subsidiaries. The Commission makes its determination by observing whether, at the time of the purchase, a lower price was offered by a nonaffiliate but ignored by the utility. If so, the additional costs incurred would be disallowed. The Arizona staff noted, however, that this has yet to occur with an Arizona electric utility. The Oregon Commission reported that, while the staff asserted that they do not use a market price concept, they reported they would not allow a utility to pay more than the market price. The West Virginia staff indicated that the commission has adjusted to a market price the prices charged by coal producing subsidiaries if the prices are found to be higher than the market.

Other staffs reported that, while their commissions do compare the costs of goods and services supplied to a utility by its subsidiaries with the market price of such goods and services, the commissions also rely on other tests or methods to control transfer pricing abuses. The North Dakota Commission, for example, uses two criteria for coal mining subsidiaries. They are (1) whether the price at which the coal could have been bought on the open market is lower, and (2) whether the mining subsidiary sells coal to other utilities at prices lower than those charged to its parent utility. The Commission, thus, looks at the market price and also examines whether or not the subsidiary is engaging in discriminatory pricing. The North Carolina staff reported that its commission allows the utility to pay only competitive prices for goods and services received from its affiliates. However, where competitive pricing is difficult or impossible to establish, the Commission allows the transfer prices to reflect costs and to contain an element of profit or return on investment not to exceed the most recent rate of return the Commission set in the utility's general rate case. In New Hampshire, the Commission staff compares the transfer price to a market price by making comparisons with the prices offered by other sources of supply. Yet, the New Hampshire Commission oversees affiliate transactions by requiring these affiliated contracts to be filed and by conducting staff studies to determine that the costs of the affiliate good or service are fair and reasonable.

The California Commission staff stated that in instances where market data are not available the Commission reviews the terms of contracts and agreements between a utility and its subsidiaries to determine the reasonableness of the costs. In every instance, however, the California Commission also reviews the earnings of the subsidiaries to ensure that the subsidiaries are not earning a rate of return greater than that authorized for the utility. If the affiliate does earn a rate of return greater than that authorized for the utility, the Commission makes a ratemaking adjustment to reduce appropriately the costs of the affiliated transaction and the utility's payments to the subsidiary.

Several other staffs reported that their commissions also use an approach similar to the utility rate-of-return approach used by the California Commission. The Florida Commission, for example, does not regulate affiliate transactions directly. Rather, the commission only allows certain costs to be passed on to the ratepayers. The Commission does compare affiliate transactions with similar transactions on the open market. The Commission allows the affiliates to price their transactions at cost, which, except for one service company, includes a rate of return on equity equal to the mid-point of the utility's allowed range for rate of return on equity. The Commission relies on financial audits conducted by independent accounting firms to determine the affiliates' and subsidiaries' costs of service. The Commission staff reviews these audits to determine whether particular items warrant further investigation. Similarly, the Michigan Commission compares the affiliated transaction to prices of third-party transactions, and rates are set as though the subsidiary's earned return was at or below the utility's authorized return on common equity.

Other commissions require that affiliate transactions be priced at cost. Typically this would require the commission to determine the subsidiaries' costs of service. For example, the Oregon staff reported that, while the Commissioner does not regulate the affiliate, the Commissioner does make rate case adjustments to the utility based on the affiliate's cost of service. The Commissioner examines the affiliate's accounting records to determine its return on sales to the utility. The Bridger Coal Company, for example, is a Pacific Power & Light Company affiliate, and it is constrained to earn no more on its sales to Pacific Power & Light Company than Pacific Power & Light is allowed to earn on its utility operations. The Texas Public Utility Commission has used a cost of service approach for fuel affiliates to determine the reasonableness of the affiliate transaction costs. But, the Commission regulates the affiliates' costs of service to assure that only reasonable costs are included in the utility's cost of service. The Washington Commission uses a standard that allows the utility to recover the cost to the affiliate of providing the goods and services plus a fair return on the affiliates' investment. The Washington staff emphasized that the Commission does not regulate the affiliate's cost of service. Rather, it uses the affiliate's actual cost plus a fair return on its investment as a substitute for the amount billed to and paid by the utility. The Pennsylvania Commission staff reviews the costs for services performed by an affiliate. They review the method used to allocate cost and how the cost was determined. The Commission also uses management audit consultants to determine if the service can be provided for less by third parties. The West Virginia staff noted that a cost-of-service approach is used for the Allegheny Generating Company. Prorations of joint costs are checked for reasonableness.

Allocation of Joint Costs

According to the staffs, most commissions have procedures for examining the joint administrative and other operating costs of an electric utility and its subsidiaries in order to control and prevent cross-subsidies. However, no particular method or formula is used for separating the joint costs between the utility and the subsidiary. Also, most commission staffs reported that commission or staff examination of joint administrative and other operating costs is usually conducted in audits, rate case audits, or rate case proceedings. There are, however, a few exceptions. The Illinois Commission staff reported that cost allocation methodologies are determined or reviewed by the Commission at the time the subsidiary is formed. The methods or formulas established for cost allocation to prevent cross-subsidies are determined on an individual company or account basis. The Nevada Commission allocates common costs based on percentage of net plant. Revenue generation is considered as an allocation basis when no other basis is reasonable or germane. The New York staff reported that the Commission does use particular formulas for separating joint costs. An example given was using time sheets to allocate payroll costs.

Some staffs reported that their commissions review, for reasonableness, the allocation formula used by a utility and its affiliates. The South Carolina Commission staff, for example, reported that during a rate case audit its Commission commonly reviews the factors that are employed by the companies to separate utility and nonutility costs. The Texas Commission staff reviews intercorporate billings and cost allocations in connection with rate proceedings. If an affiliate has a formula for cost allocation, the staff would review it for reasonableness. The staff requires proof of costs, usually in the form of invoices, payroll records, contracts, and other documents. The staff reviews the utility's external auditor's "consolidated and affiliated" work papers to assess the utility's existing internal controls for recording affiliate transactions. The North Carolina staff reported that, although its Commission has no set formula for the allocation of joint administrative and overhead costs, the Commission does require each regulated company to provide its method of cost allocation to the Commission and to defend the fairness and reasonableness of the costs allocated. Similarly, the Ohio Commission staff, as a part of its audit program during a rate case investigation, requests that a utility describe all the services provided by an affiliated company so that the services can be reviewed for accuracy, reasonableness, and proper allocation. The Washington Commission examines the books of subsidiaries to ensure that all of their costs are properly reported.

Allocation of Earnings or Profits from the Operation or Sale of a Subsidiary

According to most staffs, their commissions do not have any set formula for the allocation between ratepayers and stockholders of profits resulting from the operation of an electric utility's subsidiary. Some do, however. Several state commission staffs reported that all the profits from an electric utility subsidiary's earnings go to the subsidiary's shareholders. The Alabama Commission staff, for example, reported that profits (and losses) revert to the stockholders. The Massachusetts Department staff stated that there is no set formula for an allocation of profits; but service companies, under S.E.C. rules, operate at cost, and a subsidiary's profits are generally separate and "below the line." The Utah staff noted that the subsidiary in Utah was set up on a stand-alone basis. The rate- payers receive none of its profits and suffer none of its losses. The Ohio Commission staff also reported that its regulated utilities are treated on a stand-alone basis and that gains or losses of nonregulated entities are not treated for cost of service purposes. The Illinois Commission has established several accounts for dealings with subsidiaries, each of which is "below the line." The Colorado Commission staff reported that all profits and losses of a subsidiary or affiliate are borne by the share- holders. The ratepayer would benefit or lose only through ancillary effects on the utility's rate of return; however, the commission modifies the rate of return to protect the ratepayer from the adverse effects of losses.

A few staffs reported that their commissions treat a subsidiary differently if the subsidiary is engaged in a business related to the utility, and is providing service to the utility. The Idaho Commission staff, for example, reported that the subsidiary is treated on a stand-alone basis and is separated from utility operations if it is engaged in an unrelated business. In this case, any profits or losses from the subsidiary's operations flow to the shareholders. But, if a subsidiary is engaged in a related business, i.e., a business that is vertically integrated with that of the utility, then it is allowed the same return as the utility for services performed. For example, the Idaho Public Utilities Commission rolls the investment of an affiliated coal mining company into utility operations so that the subsidiary receives the same return as the utility. Likewise, the North Carolina Commission does not require utilities to share with ratepayers any profits from purely nonutility affiliated operations. For example, an affiliate of one of the electric utilities sells appliances and is a distributor of electrical supplies and equipment; none of the profits or losses from its operations is shared with the ratepayers. However, the same electric utility has a coal mining affiliate, and the Commission has allowed some losses from those operations to be charged to the ratepayers. Similarly, the South Carolina Commission looks at the affiliate's or subsidiary's operations separately. So long as the utility is not subsidizing nonutility operations and the subsidiary is not a threat or a detriment to the utility, the Commission does not consider the profit or loss from nonutility operations. The Commission does review the prices that a utility pays to its affiliates and the allocation of costs between utility and nonutility operations. The Commission, for example, limited the price for coal from an affiliated mine to cost plus the return allowed for utility operations.

The staffs of two commissions indicated that ratepayers get (or will get) some portion of the profit resulting from the operation of an electric utility subsidiary. The Maine Commission staff stated that 100 percent of the profit goes to the ratepayers. The staff of the Minnesota Commission noted that currently the profits (and risks) of a subsidiary are assigned entirely to the shareholders. However, the Commission has stated that it would prefer in the future to assign approximately 5 percent of a subsidiary's profits to the utility ratepayers to compensate for unquantifiable risks.

The staffs of a few commissions stated that they review the allocation of profits (between ratepayers and stockholders) resulting from a subsidiary's operation on a case by case basis given the particular facts and circumstances of each case. For example, the New Jersey Board of Public

Utilities may require, under its general statutory jurisdiction, treatments of utility investment (during rate case proceedings) that are different from those prescribed by the FERC Uniform System of Accounts.

Thus far, there have been very few instances in which electric utilities have sold unregulated subsidiaries. In the cases where an unregulated subsidiary was sold, the staffs of the commissions reported a variety of treatments in deciding who, the ratepayers or the stockholders, should benefit from the earnings from the sale.

The staffs of the North and South Carolina Commissions reported that coal mining subsidiaries were sold at losses. The South Carolina Commission allowed recovery of a portion of the utility's loss from ratepayers amortized over a ten year period. The North Carolina Commission has not yet acted on the requests by two companies to have the ratepayers share in the losses. The disposition of the losses from the sale of the subsidiaries will probably be raised in future rate cases. The West Virginia Commission staff also reported that the issue of who gets the benefit of the profit from the sale of coal producing subsidiaries by its jurisdictional utility has not yet been addressed.

The California Commission staff indicated that there have been instances in which electric utilities have sold unregulated subsidiaries. The Commission's decision as to who should benefit from the sale has varied according to the particular circumstances of each case.

The South Dakota Commission staff, on the other hand, indicated that, while there have been instances where electric utilities have sold unregulated subsidiaries, the Commission did not determine who should benefit from the earnings from the sale.

The staffs of two commissions noted that, although they have not experienced a sale of an unregulated subsidiary, they have opinions on how the benefits of such a sale would be handled. The Pennsylvania Commission staff stated that since its Commission does not have any jurisdiction over a sale of an unregulated subsidiary, the profits or losses from such a sale would go to the stockholders. The Texas Commission staff noted that, from a theoretical standpoint, the Commission would probably require the sharing of benefits from such a sale to the extent that the ratepayers had contributed to the profits or equity of the subsidiary.

Summary

The survey responses show the activity in the establishment of subsidiaries in the electric utility industry. Fuel exploration and development subsidiaries are the most common type of subsidiary with real estate subsidiaries being second, and telephone-telecommunications and fuel transporation-transloading subsidiaries being a distant third and fourth, respectively.

The survey responses also show that most staffs responded that their commissions do not have the authority to approve or disapprove the establishment of electric utility subsidiaries.

For those commissions that claim to have authority over the establishment of an electric utility subsidiary, most requests filed by utilities to establish such entities were approved. However, in one state several applications were withdrawn.

The traditional reasons were cited for the establishment of subsidiaries, including claims on the part of the utility that a subsidiary would help save the ratepayers money, improve the utility's technical expertise, allow expansion into ancillary businesses or foreign markets, and give the proper incentive to management to be productive. For the most part, state commissions have not formally evaluated whether the stated and theoretical benefits of establishing a subsidiary have been realized.

Those commissions which do have authority to approve or disapprove the establishment of subsidiaries use several types of procedures. Some have separate hearings; others handle a request to establish subsidiaries at securities issuance proceedings; some use either. At the hearings or proceedings, several commissions consider the appropriateness of establishing the subsidiary or affiliate. These commission assess the potential risk, posed by the subsidiary, to the ratepayer. However, only a few commissions then periodically reassess the continued appropriateness of the subsidiary. The staffs of most of these commissions indicate that the source of an electric utility's financing of its subsidiaries is mainly retained earnings. Only a few commissions oversee the obtainment by electric utilities of investments and loans to finance subsidiaries. Several commissions also have the authority to impose special accounting and reporting requirements on utilities that establish subsidiaries.

Nearly all commissions responding to the survey reported that they have authority, whether explicit or implicit, to gain access to the books and records of electric utility subsidiaries, affiliates, or the holding company parent of a utility. In most instances, company officials have been cooperative in providing records.

Most commissions do not have authority to order the divestiture of an electric utility subsidiary once established.

Only a few of the state commissions with authority over subsidiary establishment are now formulating a comprehensive strategy for dealing with the establishment of subsidiaries. Overall, most commissions do not devote a great deal of time or expense to regulation of subsidiary-related issues.

Most commissions do review the business relationships between an electric utility and its subsidiaries on a periodic basis, most commonly in the context of rate case proceedings. In order to help isolate transfer pricing abuses and to prevent cross-subsidies between a utility and its subsidiaries, most commissions require the utility (1) to keep its accounts in accordance with a Uniform System of Accounts, and (2) to separate the costs of a subsidiary from its utility parent.

Most commissions also try to isolate and control transfer pricing abuses by use of one of several methods including a reasonableness or prudence test, a market-price test, a cost-plus-reasonable-return basis, and a cost plus the utility's-rate-of-return basis.

Most commissions also have procedures during commission audits or rate cases for examining the joint and other operating costs of an electric utility and its subsidiaries to control and prevent cross-subsidies. However, most commissions indicate that no particular method or formula is used for separating joint costs. Most commissions also report that they have no set formula for allocating earnings or profits from the operation or sale of a subsidiary. There are, however, a few significant exceptions to these generalizations.

CHAPTER 4

DEFINING COMMISSION AUTHORITY

While the staffs of most state public utility commissions may believe that their commissions have no authority over the establishment or divestiture of electric utility subsidiaries, commissions and their staffs might nonetheless wish to re-examine their authority to deal with the problems associated with transfer pricing and cross-subsidization of costs. In this chapter, the authors examine two issues of legal authority. First, the authors consider possible sources of state commission authority to determine the existence of electric utility subsidiaries, affiliates, and holding companies. Second, commission authority to prevent possible cross-subsidies is examined.

Commission Authority Over the Establishment and Divestiture of Subsidiaries and Affiliates

Though most state commissions do not have explicit statutory authority to approve or disapprove the establishment by electric utilities of subsidiaries, nor do they have an explicit authority to order the divestiture of an existing subsidiary, there may be sources of authority available to these commissions that are implicit in their general statutory provisions. One such provision would empower the commission "to protect the public interest." Also there may be existing sources of authority available to the commission that, on their face, may seem limited, but can be interpreted broadly. Each of these sources of authorrity -- explicit, implicit, and limited -- are discussed in their turn.

Explicit Authority

Several commissions have explicit statutory authority over the establishment of subsidiaries. A good example is a Maine statute that provides that all reorganizations by a public utility are subject to commission approval. The statute broadly defines "reorganization" and gives the Maine Public Utilities Commission jurisdiction over all reorganizations for the purpose of forming holding companies. (It is not clear, however, whether the statute also requires Commission approval for the formation of subsidiaries.) But the statute does have an elastic clause that enables the Commission to decide what public utility actions constitute a reorganization and fall under the statute.[1]

Another type of explicit authority that can be as certain and perhaps more flexible than explicit statutory provisions is a commission order that fleshes out a more general enabling statute. One example of a state taking this approach is New Mexico. The New Mexico Public Service Commission issued General Order No. 39 which implements Chapter 109 of the New Mexico Law of 1982. Among other things, the order promulgated regulations concerning the formation of holding companies, utility subsidiaries, and divestiture of a subsidiary.[2]

An obvious advantage of a clear and explicit grant of authority is that it gives both the regulator and the utility a clear understanding of their respective powers and responsibilities. For example, a commission can allow the establishment of a subsidiary on the condition that the utility provide the commission with access to the accounts, records, and (when necessary) the corporate officers of the subsidiary or affiliate.

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[1]An Act to Provide that Corporate Reorganization Affecting Public Utilities Be Subject to Approval by the Public Utilities Commission, H.P. 2267-L.D. 2114, 35 Me. Rev. Stat. Ann. § 104(1)-(4). This act is abstracted in appendix C.

[2]See In the Matter of the Adoption of Proposed Rules Regarding Class I and Class II Utility Transactions under Chapter 109, Laws of 1982 (General Order No 39), Case No. 1759, Order (NMPSC, November 30, 1982). This order is abstracted in appendix C.

By this means, a commission can set up regulatory mechanisms at the beginning of the subsidiary's corporate life to safeguard the public from the potential harm that could arise from cross-subsidies and abuses.

Several very good examples of the types of conditions that a commission might place on the establishment of a subsidiary or affiliate can be found in appendix C of this report. One of these examples are discussed briefly here. The Hawaii Public Utilities Commission (PUC) allowed the Hawaiian Electric Company to merge with Hawaiian Electric Industries, Inc. in order to form a holding company, subject to several conditions. These conditions included the Commission and the consumer advocate having access to, and the right to inspect, the books and records of the holding company and its subsidiaries; the utility providing financial records and explanations of intercompany transactions and the basis of allocations of joint costs; and the Commission having access to officers, directors, employees, and agents of the holding company. The Hawaii PUC reserved the right to investigate and review any affiliated transaction and allocations of common expenses. The Commission placed limitations on loans between the utility and the holding company and on the transfer of assets and liabilities between the utility and its holding company as well as on dividend payments by the utility. The Hawaii PUC also retained its authority over the utility's security issuances and provided that the holding company could not divest itself of the utility's stock without prior Commission approval.[3]

Several other state commissions require similar conditions and a few state commissions have added other requirements before approving the establishment of a subsidiary or an affiliate by an electric utility. The Illinois Commission, for example, is empowered by the Illinois Public Utilities Act to inquire about and to prescribe the apportionment of

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[3]In the Matter of the Application of Hawaiian Electric Company, Inc. for approval of the merger of New HECO Inc. into it and related matters and the Application of Hawaiian Electric Industries, Inc. to own all the issued and Outstanding Common Stock of Hawaiian Electric Inc., Docket No. 4337, Order No. 7256 (Hawaii PUC, Sept. 29, 1982). This order is abstracted in appendix C.

capitalization, earnings, debts, and expenses.[4] A Maine Act empowers the Maine Public Utilities Commission (PUC), in the event of a corporate reorganization, to be able to identify, review, and approve or disapprove all affiliated transactions, to assure that the utility's ability to attract capital on reasonable terms is not impaired, and to assure that utility credit is not impaired or adversely affected.

In addition the Maine act gives the Maine PUC very broad powers to impose conditions which it deems necessary to protect the interests of the ratepayers or investors. The Commission's authority includes the power to set conditions to assure that the ability of the utility to provide safe, reasonable, and adequate service is not impaired, to assure that the utility continues to be subject to laws, principles, and rules governing the regulation of public utilities, to assure that reasonable limits are imposed on the total level of investment in nonutility businesses, and to assure that neither ratepayers nor investors are adversely affected by the reorganization. One final elastic clause allows the Maine PUC to take whatever remedial steps are necessary to protect the interests of the utility, its ratepayers, or its investors, including divestiture.[5]

The New Mexico Public Service Commission's General Order Number 39 requires that a utility file and receive Commission approval of a general diversification plan before entering into a "class II transaction." Class II transactions include the formation of a corporate subsidiary, a public utility holding company, certain other acquisition and agreements, and divestiture of a corporate subsidiary. Commission approval of the general diversification plan is given only if the Commission finds that the level of investment involved in the transaction appears to be reasonable and that the utility's ability to provide adequate utility service at just and reasonable rates is not adversely or materially affected by the transaction. The General Order lays out eight additional requirements that the utility must meet to gain Commission approval of its general diversification plans. One of the more interesting requirements is that

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[4]See footnote 1, above.

[5]See footnote 2, above.

the utility have an allocation study or a management audit performed, when required by the commission, at the utility's own expense by a consulting firm chosen by and under the direction of the Commission. The New Mexico Commission's approval is also conditioned on the utility providing the Commission with (1) notice of all new or expanded lines of business entered into by the utility or its affiliate, (2) notice of any transfer of rights, obligations, or assets between the utility and the affiliate, and (3) a detailed annual report. The detailed annual report not only updates the information contained in the general diversification plan, but also provides information that the Commission needs to be certain that its imposed conditions are being observed.[6]

Implicit Authority

Even if a commission does not believe that it has explicit authority to authorize or disallow the establishment of an electric utility's subsidiary or affiliate, a commission might find that it has an implicit power to require implementation of safeguards to protect the ratepayers from the potential abuses that could result from a subsidiary or affiliate being established. One example of a commission asserting this right to require safeguards is a recent Idaho Public Utilities Commission order.[7] The Idaho Commission concluded that although it did not have jurisdiction to regulate the formation of a nonutility subsidiary, it did have the authority to require safeguards to be implemented to ensure that the formation of a subsidiary did not have a detrimental impact on the utility's regulated operations.

State commissions might also have an implicit authority to order the divestiture of an affiliate or subsidiary if the continued existense of

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[6]See footnote 3, above.

[7]See In the Matter of the Application of Utah Power & Light Company for (1) An Order Disclaiming Jurisdiction, or (2), in the Alternative, an Order Authorizing it to Form and Finance a Wholly-Owned Subsidiary, Order No. 18784, Case No. U-1009-4 (Id. PUC, April 4, 1984). This order is abstracted in appendix C.

the entity would cause harm to the utility or its ratepayers. Recall that a few state commission staffs recognized in their survey responses that such an implicit authority might exist, particularly in circumstances where the financial health of the utility was threatened.

Limited or Indirect Authority

Many state commissions have a limited or an indirect authority to approve or disapprove the establishment by an electric utility of a subsidiary, a holding company, or an affiliate. As shown in table 4-1, most state commissions require their approval prior to merger or consolidation, the issuance of new common stock, the purchase of the securities of other utilities, and the purchase or issuance of securities by utilities operating in the state but incorporated in another state. This is in stark contrast to the scope of state public utility commission authority that existed at the time that the Public Utility Holding Company Act of 1935 was enacted. As noted earlier, in chapter 1, few state commissions had authority over securities issuance prior to 1935.

If a state commission does not have explicit authority to approve or disapprove the establishment of subsidiaries and does not want to rely upon an implicit authority to do so, it could look to its limited authority to approve or disapprove mergers or consolidations, or to approve or disapprove the underwriting, issuance, sale, or purchase of common stock. State commissions usually have similar powers with respect to most other forms of securities, such as mortgage bonds, debentures, preferred stock, and long-term commercial notes. Most state commissions do not have the authority to require their prior approval of an issuance of a short-term note with a maturity period of less than one year.[8] The establishment of a new subsidiary or the formation of a holding company usually requires the issuance of stock or other securities. When a

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[8]See National Association of Regulatory Utility Commissioners, 1983 Annual Report on Utility and Carrier Regulation (Washington, D.C.: by the author, 1984), pp. 514-515.

TABLE 4-1

STATE COMMISSION[1] AUTHORITY TO REQUIE PRIOR APPROVAL BEFORE ELECTRIC UTILITY MERGERS, CONSOLIDATIONS, NEW STOCK ISSUANCES, AND THE SALES OR PURCHASES OF THE SECURITIES OF OTHER UTILITIES

State Commission	Merger or Consolidation	New Common Stock	Purchase of Securities of Other Utilities	Purchase of Securities by Utilities Operating in the State, but Incorporated in Another
Alabama PSC	Y	Y	Y	Y
Alaska PUC	Y	N	Y[3]	Y
Arizona CC	Y	Y	Y	Y
Arkansas PSC	Y	Y	Y	Y
California PUC	Y	Y	Y	Y
Colorado PUC	Y	Y	N	Y
Connecticiut DPUC	Y	Y	Y	Y
Delaware PSC	Y	Y	N	Y
D.C. PSC	Y	Y	Y	Y
Florida PSC	N	Y	N	Y
Georgia PSC	Y	Y	Y[4]	Y
Hawaii PUC	Y	Y	Y	Y
Idaho PUC	Y	Y	N	Y
Illinois CC	Y	Y	Y	Y
Indiana PSC	Y	Y	Y	Y
Iowa SCC	Y	N	N	N
Kansas SCC	Y	Y	Y	Y
Kentucky PSC	Y	Y	N	Y
Louisiana PSC	Y	Y	Y	N
Maine PUC	Y	Y	Y	Y
Maryland PSC	Y	Y	N	N
Massachusetts DUP	Y	Y	Y	N
Michigan PSC	Y	Y	N	Y
Minnesota PUC	Y	Y	N	Y
Mississippi PSC	Y	N	N	N
Missouri PSC	Y	Y	N	N
Montana PSC	N	Y	N	Y
Nevada PSC	Y	Y	Y	Y
New Hampshire PUC	Y	Y	Y	Y
New Jersey BPU	Y	Y	Y	Y
New Mexico PSC	Y	Y	Y	Y
New York PSC	Y	Y	Y	Y
North Carolina UC	Y	N	Y	Y
North Dakota PSC	Y	Y	Y	Y
Ohio PUC	Y	Y	Y	Y
Oklahoma CC	Y	Y	Y	N
Oregon PUC	Y	Y	Y	Y
Pennsylvania PUC	Y	Y	Y	Y
Rhode Island PUC	Y	Y	Y[5]	Y
South Carolina PSC	Y	Y	Y	Y
South Dakota PUC	Y	Y[2]	N	N
Tennesee PSC	Y	Y	N	Y
Texas PUC	Y	N	Y	N
Utah PSC	Y	Y	Y	Y
Vermont PSB	Y	Y	Y	Y
Virginia SCC	Y	Y	Y	N
Washington PSC	Y	Y	Y	Y
West Virginia PSC	Y	N	Y	N
Wisconsin PSC	Y	Y	Y	N
Wyoming PSC	Y	Y	Y	Y

Source: National Association of Regulatory Utility Commissioners, 1983 Annual Report on Utility and Carrier Regulation (Washington D.C.: by the author, 1984), table 34 at pp. 514-515.

[1]For our purposes state commission includes the District of Columbia Public Service Commission. No commission is listed for Nebraska because there is no regulation of electric utilities. Y means "yes, the commission does have such authority. N means "no, it does not."

[2]The Black Hills Power Light Company only.

[3]The purchase of a controlling interest of a utility is certified by the Alaska PUC.

[4]If purchased as a part of a merger.

[5]Approval is required for the purchase of stock only.

utility requests approval of the issuance of such a security, a state commission might take that opportunity to determine whether it wishes the subsidiary ought to be established or, what safeguards ought to be put in place at that time to protect the ratepayer.

Many state commissions also assert the right to participate as a party in any reorganization proceeding by a utility.[9] The occasion of a corporate reorganization is an opportunity to question whether the establishment of a proposed subsidiary or holding company with affiliates is in the best interests of the ratepayer. The commission might, at that time, set up the appropriate regulatory safeguards to isolate and prevent cross-subsidies from occurring.

Exempt Holding Companies: A Special Concern

The creation by electric utilities of exempt holding companies can create special problems that may require a commission to have explicit statutory authority over the establishment of subsidiaries and affiliates. For example, an (exempt) intrastate holding company can assert that its out-of-state nonutility subsidiaries are not under state commission jurisdiction and that neither the holding company nor its out-of-state subsidiaries need to supply information on its affiliated transaction or how it allocates joint and common costs. Similar problems could arise if the exempt holding company in question has a "predominantly a public utility" type of exemption under section 3(a)(2) of the PUHCA. As noted

[9]These commissions are the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Indiana Public Service Commission, the Louisiana Public Service Commission, the Maine Public Utilities Commission, the Michigan Public Service Commission, the New Hampshire Public Utilities Commission, the New Jersey Board of Public Utilities, the North Dakota Public Service Commission, the Oregon Public Utility Commissioner, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, the Washington Utilities and Transportation Commission, and Wisconsin Public Service Commission. See the National Association of Regulatory Utility Commissioners, 1983 Annual Report, p. 515. The New York Public Service Commission requires agency approval of a corporate reorganization.

earlier in chapter 1, such an exempt holding company is itself predominately a public utility. It is allowed to have its own utility operations in the state in which it is organized and in the contiguous states. The section 3(a)(2) holding company is allowed to set up "minor" utility subsidiaries in other states. Because the holding company is itself a regulated utility, the issue of whether to allow it to set up nonutility subsidiaries is approached no differently than if the issue had been raised by any other regulated electric utility. The problem with a section 3(a)(2) holding company is trying to account for the allocation of joint and common costs. The holding company might assert that its out-of-state utility subsidiaries are outside the commission's jurisdiction and that the commission has no right of access to the out-of-state books and records.

Because of the possible new difficulties that a state commission may face when dealing with exempt holding companies, a commission might find it desirable to have explicit statutory authority to regulate both the establishment of an exempt holding company and its subsidiaries.[10] The enactment of an explicit holding company statute can also have the virtue of putting to rest controversies that could otherwise linger for years.[11]

Commission Authority to Prevent Cross-Subsidies and Other Abuses

The sources of commission authority to prevent cross-subsidies and other abuses in affiliate transactions and to allocate common costs are discussed here.

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[10] A recent case tested the constitutionality of state statutes that would allow a state to block the formation of holding companies. The United States Court of Appeals for the Fourth Circuit upheld the Maryland law at issue. The United States Supreme Court refused to hear the case. 760 F.2d. 1408 (1985).

[11] See, for example, "Tough Wisconsin Holding Company Bill Headed for Governor's Signature," Electric Utility Week, October 28, 1985, pp. 9-10.

Commission Authority Concerning Affiliate Transactions

There are two sources of commission authority. They are regulating affiliate transactions on the basis of explicit statutory authority or on the commission's own implicit authority.

Explicit Statutory Authority

Most commissions appear to rely on an explicit statute to enable them to identify and control any cross-subsidies that result from affiliate transactions. The most frequently utilized type of statute appears to be an affiliated-interest statute. About half the states have these statutes which define what constitutes an affiliated interest and then provide procedures that are applicable for affiliate transactions.[12] There are two types of affiliated-interest statutes. There are those statutes that provide for a reporting of all affiliate transactions: the affiliated-interest filing or reporting statutes. Other statutes require a contract between a utility and an affiliate be submitted to and approved by the state utility commission before the contract becomes effective: the affiliated-interest contractual preapproval statutes.

An affiliated-interest reporting statute is the more common. An example is the Illinois Public Utilities Act, abstracted in appendix C.[13] These statutes are useful because they highlight the existence of an affiliate transaction to state regulators so that the transaction can receive special attention during a rate case.

Affiliated-interest reporting statutes often explicitly authorize a commission and its staff to have access to and the right to inspect the books and records of affiliated companies. Appendix C contains examples of several of these statutes. One of the more interesting examples is the North Carolina statute which authorizes the Commission, the

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[12]See Douglas W. Hawes, Utility Holding Companies (New York: Clark Boardman Company, Ltd., 1984), chapter 10, for a good discussion of state and federal regulation of affiliated transactions.

[13]See footnote 1, above.

Commission staff, and the public (advocate) staff to have access to and to inspect the books and records of affiliated companies. The right to inspect the books and records applies to all accounts, agreements, and transactions between the North Carolina utilities and their affiliates where the records relate directly or indirectly to providing intrastate service. This right extends to books and records located outside North Carolina, as well as within. The enforcement provision of the statute is particularly noteworthy. It provides that if any affiliated company refuses to permit inspection of its books, then the Commission is empowered to order the North Carolina utility to show cause why it should not secure the books and records from its affiliated corporation or why their franchise as a public utility in North Carolina should not be cancelled.[14]

The other type of affiliate transaction statute is the affiliated-interest contractual preapproval statute. There are several examples in appendix C. One is discussed here. The Pennsylvania statute provides that, unless and until a contract or arrangement between a public utility and an affiliated corporation has received written approval from the Commission, the contract or arrangement is not valid or effective. The statute provides that the Commission can approve a contract or arrangement only if, upon investigation, it is clearly established that the contract or arrangement is reasonable and consistent with the public interest. This last clause could be interpreted expansively. A commission might choose to examine not only the terms and conditions of a contract, but also the type of contract to determine if it was consistent with the public interest. If it chose to do so, the commission might look at whether the contract had an anti-competitive effect, such that it would tend to restrain trade and destroy existing markets; or, a commission could choose to look at generic types of contracts or arrangements to see if the contract would produce synergies for the utility and its affiliate that could lower the utility's operating costs. Indeed the statute allows the commission to approve prospectively a class or category of transactions.

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[14]General Statutes of North Carolina, § 62-51, abstracted in appendix B.

The Pennsylvania statute demonstrates recognition that the small size of some transactions can make this form of regulation not cost-effective. The statute provides a remedy: no commission approval is required where the amount of consideration involved is not in excess of \$10,000 (or 5 percent of the par value of outstanding stock, whichever is smaller.) However, regularly recurring or continuing transactions that would aggregate to a greater annual amount cannot be disaggregated to come under this exception.

The Pennsylvania statute provides that the Commission has continuing supervisory control over the terms and conditions of the approved contracts so far as is necessary to protect and promote the public interest.

Further, the Pennsylvania statute expressly provides that the Commission is not precluded from subsequently disallowing or disapproving expenditures made pursuant to contracts that were approved by the Commission if actual experience shows that the payments were unreasonable. This provision allows the Commission a second look at each expenditure so that it is not foreclosed from reconsidering whether each expense is reasonable. The provision also puts the utility on notice that it cannot justifiably rely on prior Commission approval of a contract to permit into rates a subsequent unreasonable expenditure.[15]

Implicit Authority

Even without explicit statutory authority, state commissions have an implicit authority to identify and control any cross-subsidies that result from affiliated transactions. This implicit authority is implied by a commission's expressed authority to set rates that are "just and reasonable" and to assure that the utility "provides adequate service at the lowest reasonable cost." A commission can, of course, then use its general ratemaking authority to exclude from rates the portion of the expenditure in excess of the market rate.

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[15]See Pennsylvania Consolidated Statutes, §§ 2101-2107. This statute is abstracted in further detail in appendix C.

Commission Authority Concerning the Allocation of Common Costs

All state commissions have the authority to allocate common costs. This authority is often based on statutory provisions like the Illinois one which allows a state commission to "inquire as to and to prescribe the apportionment of capitalization, earnings, debts, and expenses between regulated and nonregulated activities."[16] Other sources of state commission authority may be less direct.

When common costs between a utility and a subsidiary engaged in a nonregulated activity are involved, the portion of the common costs that are not related to providing service are excluded from rates. In the next three chapters, the authors analyze the strengths and weaknesses of various tools which a state commission can use to prevent cross-subsidies from being passed on to ratepayers.

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[16]See Illinois Public Utilities Act, § 12, which is abstracted in appendix C. See also Mo. Ann Stat. 393.140(12) (Vernon, 1982). See generally Hawes, Utility Holding Companies, pp. 9-1 - 9-9.

CHAPTER 5

IDENTIFYING AND MONITORING COSTS

Most commissions do not assert authority to regulate the establishment of subsidiaries of electric utilities. Nearly all commissions, however, regulate the utility-subsidiary relationship once a subsidiary has been established. To do so, commissions use a variety of methods to identify and monitor costs that result from the utility-subsidiary relationship. This chapter addresses the methods that commissions do use or could use to better identify and monitor such costs.

The chapter is divided into two sections: the first focuses on techniques available to state commissions ancillary to their ratemaking authority which can be used to identify and track costs associated with affiliate transactions. It also discusses various methods for allocating joint costs among the utility and its subsidiaries.

The second section presents various methods for monitoring diversified utilities that might allow state commissions to improve the thoroughness of the regulation of diversified utilities. The policies discussed include changing the corporate structure, audits, affiliated interest filing requirements, and accounting and recordkeeping procedures.

Cost Identification

One of the many regulatory problems raised by the diversification of regulated utilities into nonregulated areas of business is monitoring the flow of costs[1] from parent to subsidiary (and vice versa) in order to

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[1]In theory, all "costs" start out as assets, which are expended--and thus become "costs"--as they are depleted or used in the production process. What regulators are really trying to identify is the flow of assets--both monetary and nonmonetary--from the utility to its affiliates. Thus while the term "cost transfer" is used throughout much of this discussion, it is not meant to narrow the focus of the inquiry to those transactions wherein the flow of assets from a parent utility would appear as a "cost" on the parent utility's income statement. Rather, it is meant to include all asset transfers.

prevent cross-subsidization of the nonregulated subsidiary by the regulated parent. Conceptually this problem is no different from that faced by regulators of utilities engaged in one or more lines of nonregulated activity. However, where a subsidiary is involved, there may be a separate legal entity with a separate accounting system. The key is to identify the cost flows from regulated to nonregulated endeavors, so that these costs can be reviewed for reasonableness and excess "unreasonable" amounts assigned to "below-the-line" accounts.

Cost Transfers and Common Costs

Cost transfers between a utility and its subsidiary may occur in a variety of ways and in a variety of transactions. For convenience sake, we divide these into two categories of cost transfer: (1) formal transfers and (2) casual transfers.[2] Formal transfers involve the transfer of assets, goods, or services in an identifiable transaction between separate legal entities. In a formal transfer, the transfer is recorded on the books of both companies. Examples of formal transfers include the purchase of coal from a mining subsidiary (goods transfer), the sale of land to an affiliated real estate company (asset transfer), and the provision of transportation services by a subsidiary short-line railway (services transfer). Thus, a formal transfer involves a readily identifiable transaction, whereby an asset, good, or service is exchanged between two separate legal entities for explicit consideration. In all cases involving formal transfers, the transaction is recorded by both companies and can thus be readily traced in the course of an audit.

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[2]Any division and categorization of cost transfers is admittedly arbitrary. This categorization is consistent with that used in discussions by others. See, for example, J. Robert Malko, Gregory B. Enholm and Theodore M. Jaditz, "Energy Utility Diversification, Holding Companies and Regulation," paper presented at the Fourth Annual Public Utilities Conference, New Mexico State University, El Paso, Texas, October 1981, p. 61.

Casual transfers, on the other hand, involve either of the following situations: (a) transfers of goods or services between two separate legal entities, where the transfer is not formally recorded and does not appear on the books of either company; or (b) transfers of goods or services between regulated and nonregulated activities of a single corporate entity, which may be similarly unrecorded. Situation (a) typically arises where there is a close working relationship between regulated parent and non-regulated subsidiary. Where such close relationships between affiliated entities exist, casual transfers can occur in a variety of ways. Casual transfers would include occasional rent-free use of office space, time spent on work related to nonregulated activity by an officer of the utility, and cash advances or informal loans made to a nonregulated subsidiary.

In addition to identifying and tracking cost transfers, regulators must also determine the proper allocation of joint or common costs. The question of joint costs most frequently arises where a public utility engages in both regulated and nonregulated activities.

Casual Transfers and the Cost Identification Process

Casual cost transfers between utilities and subsidiaries or between regulated and nonregulated portions of a utility's business are perhaps the most difficult type of cost transfers to detect and monitor. This is because these kinds of transfers typically do not involve economic "exchanges" (that is, they are not purchases or sales for consideration) and, hence, do not appear on the books of either the utility or its subsidiary.[3]

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[3]Whenever a utility transfers goods or services to a subsidiary or affiliate without consideration or below market value, this constitutes an increase in the utility's investment in the utility or affiliate and should be, in theory, indicated by a debit entry in the proper investment account (either 123 or 123.1).

Casual transfers occur where a utility is engaged in both regulated and nonregulated lines of business, necessitating the apportionment of costs between regulated and nonregulated ventures. Casual transfers can also occur where there is a close working relationship between two or more affiliates. Casual transfers between affiliates are especially likely in any situation where there are shared overhead or other joint costs, or where the affiliates are vertically integrated.

Although a commission can (and typically does) prescribe procedures for the internal recordkeeping and accounting for casual transfers of goods and services between utility and nonutility operations, such procedures are often difficult to enforce, especially when the transfers are infrequent or sporadic, and involve nominal monetary amounts. In such cases, the omission of isolated transactions can rarely be detected. However, where casual cost transfers occur frequently and are part of a general scheme of close cooperation between parent and subsidiary, they can involve amounts which in the aggregate are significant. A regular pattern of casual cost transfers might be detected in the course of a well-designed management or special audit.

Because unrecorded cost transfers can only be detected in the course of an audit, vigilant regulation of diversified utilities requires the use of periodic and frequent audits in circumstances where these transfers are most likely to occur. Determining whether and how often such audits are appropriate would involve some form of cost-benefit analysis on the part of the commission, in order to weigh the cost of such procedures against the benefits (i.e., cost-savings to the ratepayers).

When a utility's nonregulated activities are small in proportion to the total, it is likely that the dollar amounts of such cross-subsidies are insignificant in relation to the utility's total operating revenues. In such cases, regular staff or management audits for the sole purpose of detecting cost transfers would likely not be warranted. However, when a utility's nonregulated revenues bear a larger proportion of the company's total revenues, the use of periodic auditing procedures to monitor casual cost transfers may well be warranted.

Similarly, where there are few recorded intercompany transactions between a utility and its affiliate, there is little reason to suspect the presence of casual transfers. But when there is a close working relationship between a utility and its affiliate, regulatory authorities may need to employ measures (i.e., audit procedures) to detect the existence of (unrecorded) casual cost transfers.

Table 5-1 lists some factors which are indicative of the kind of close working relationship between parent and subsidiary in which casual cost transfers are likely to occur. While the presence of one or more of these factors does not mean that unrecorded cost transfers are, in fact, being made, it does indicate the need for vigilance on the part of regulatory authorities.

TABLE 5-1

FACTORS INDICATING CLOSE INTERRELATIONSHIP BETWEEN AFFILIATED CORPORATIONS

* Supplier-purchaser relationship
* High volume of recorded cost transfers (in relation to total revenues)
* Transactions involving the sale of non-inventory items (assets) not sold in the ordinary course of business
* Shared physical facilities
* Shared managerial personnel
* Shared informational/computer expenses
* Other shared overhead expenses

Source: Authors

Allocation of Common Costs

One of the difficulties posed by diversification is the necessity of allocating overhead and other common costs between the regulated utility and nonregulated subsidiary. This overhead allocation problem arises whenever a utility engages in both utility and nonutility operations. However, the need to allocate overhead or other common costs can also arise where a utility and its subsidiary share equipment, facilities, management expertise, or other resources. This need to allocate common costs is not a function of the parent-subsidiary relationship, per se, but rather depends upon the degree of physical "interrelatedness" between the regulated and nonregulated ventures.

Since many public utilities, regardless of their corporate structure, are engaged in some form of nonutility operations requiring the allocation of overhead, taxes, and other common costs between above-the-line and below-the-line expense accounts, regulators are accustomed to encountering such cost allocation problems. The problem of allocating common costs between a utility and its subsidiary is conceptually no different from that of allocating common costs between divisions of a single legal entity.

The necessity for allocating common costs can be minimized by requiring--where feasible--the physical separation of regulated and nonregulated activities. However, the separation of regulated and nonregulated activities is often not feasible. In many cases, this may be because the commission lacks the authority to order the physical separation of nonregulated activities from the utility's premises. In other cases it may be because the utility's nonregulated activities are so insignificant in relation to the company's operating revenues that it would not be economically feasible--i.e., practical--to order separation. In any event, the commission can never completely avoid the necessity of dealing with cost allocation problems, since these arise--in one form or another--even in the "purest" of operating utilities. Thus, the following discussion and methods can be applied to the cost allocation problem in the context of the single corporate entity engaged in one or more nonregulated activities, as well as to the case of the parent utility and subsidiary that share certain common costs.

Before discussing specific cost allocation methodologies, a brief discussion of allocation criteria may be helpful. Cost allocation divides the expenses of a complex entity into individual segments--those segments representing different products or services. Although cost allocation is to some extent an inexact and arbitrary process, allocation methods vary as to their degree of apparent preciseness. Typically there is a trade-off between the preciseness of a given cost allocation method and the size of the costs associated with its use, since the more precise cost allocation methods typically require more time and information to use effectively.

Guidelines for the allocation of specific costs generally do not exist. However, in order to be effective a cost allocation mechanism must satisfy the following broad criteria:[4] (1) cause-and-effect logic, (2) consistency, and (3) additivity.

When economically feasible, costs should be allocated to products or services by using some cause-and-effect logic. When direct cause-effect relationships are infeasible to establish, however, other methods must be used. These would include using allocation bases such as number of employees, floor space, man-hours worked, etc. The choice of an allocation mechanism should be based on achieving an allocation which if not directly, at least indirectly recognizes cost causation. In regulated industries, therefore, revenues should not be used as an allocation basis for a diversified electric utility.[5]

An allocation must also meet the criterion of additivity. Additivity means that any amount allocated is equal to the sum of the parts into which the original amount was allocated. This assures that the expense is neither over- nor underabsorbed. Accordingly, methods of allocation not meeting this criterion are not acceptable allocators.

Consistency, of course, is of fundamental importance. One of the basic principles of accounting is to assure comparability of financial

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[4]This discussion is based generally on Charles T. Horngren, ed., Cost Accounting: A Managerial Emphasis, 5th ed., Section Five: "Cost Allocation in a Variety of Roles" (Englewood Cliffs, N.J.: Prentice-Hall, 1982), pp. 475-628.

[5]In nonregulated industries, common costs are sometimes allocated on the basis of revenues, or "net realizable value." Such allocation bases can be useful to firms faced with production and allocation decisions in two or more competitive markets. However, this allocation basis is inappropriate for a regulated monopoly. It not only violates the cause-and-effect principle, but it leads to a circularity of reasoning (i.e., prices used to set costs and costs then used to set prices). See Horngren, Cost Accounting, p. 539.

information over time. If a method of allocation is inconsistent over time, or is applied inconsistently, comparison of historical data is no longer meaningful; and there is no longer any assurance that the originally established goals of the allocation are being met.

In light of these general criteria, the cost allocation methods most recommended for use by electric utilities are listed below, in order of preference:[6] (1) direct charge, (2) functional accounting, (3) overhead studies, and (4) formulas.

Direct Charge

One method that can be used is a direct charge system. Whenever a readily measurable cost can be directly attributed to an operation, it should be. This method can be used to allocate payroll and other readily measurable costs. However, there are certain disadvantages in using a direct charge system. One disadvantage is that the system is fairly expensive to develop and often needs to be implemented on a computer. (The details that would be involved in manually implementing such a system would be overwhelming.) A simplified version of the direct charge method that might be less costly to implement would be an exception reporting system. This system would operate by noting changes from (exceptions to) a designated distribution of time or costs. One problem that exists in implementing either system is that few electric utilities presently use such systems, so that devising proper separations would be difficult.

Functional Accounting

A less costly alternative to a direct charge system would be functional accounting. Use of this system would require supplemental accounting and reporting on a functional cost center basis; standard

[6]The following discussion is based in large part on a two-volume study prepared for the Virginia Utility Legislative Committee by Ernst & Whinney. Ernst & Whinney, Accounting Procedures for Transactions Between a Regulated Utility and its Affiliates, vol. 1: Conceptual Framework (Virginia Utility Legislative Committee: 1983), pp. III 6-8.

formulas could then be prescribed for functional costs. Use of this system would permit the functional allocation of costs between the regulated utility and its subsidiary based on objective measures of activity. Although a functional accounting system is not as precise as a direct charge system, it is still preferable to the use of formulas. One advantage that a functional accounting system does have is that some utilities currently maintain and use this information for their own internal management purposes. Utilities should be encouraged to utilize this information for cost allocation purposes to the extent that their internal accounting systems permit.

Overhead Studies

Another, albeit less preferable, method that can be used to allocate costs is the use of overhead studies. Overhead studies can be based on questionnaires or actual records. Although less precise than either the functional accounting or direct charge methods, overhead studies are less costly to develop and implement. Study methods can differ depending on the data available from a utility's accounting systems; thus utilities with more elaborate systems could use overhead studies more effectively than utilities with less-developed accounting systems.[7]

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[7]The problem of properly allocating the costs associated with managerial effort admits of no easy solution. Although in theory it could be allocated according to a direct charge system for upper level management, this is hardly a satisfactory solution: not only is it impractical to require top-level management to charge off time to specific accounts, but it implicitly assumes that the value of the managerial work product is directly related to time expended, and it does not account for differences in quality. A better method would be to allocate costs for each individual (or job classification) based on pre-determined ratios. Such ratios could be based on prior overhead studies and analysis of actual work product. Such a system would alleviate the necessity for top-level management to charge off their time to specific uses. The drawback of such a system is that it would require the use of periodic management audits to verify the accuracy of the allocation basis.

Formulas

The least precise and least preferred method that can be used to allocate costs is the use of generalized formulas. This method has a few virtues, nonetheless. It is not costly to use, it is easily verifiable, and it can be used whenever the direct or indirect charge methods cannot be used due to data constraints. Generalized formulas are particularly useful where the dollar amounts to be allocated are minor. However, the other methods of cost allocation just noted are more precise and are appropriate, when feasible.

As the preceding discussion illustrates, there is no single "best" allocation method which will be appropriate in all circumstances. Selecting the appropriate cost allocation method, or combination of methods,[8] involves careful consideration of various factors, including the nature of the costs to be allocated (are they chargeable or measurable?), the materiality of the costs involved (in relation to the firm's operating revenues), the constraints imposed by the firm's existing accounting and management information systems (is the necessary data readily obtainable?), and the additional costs of implementing a more precise cost allocation system (i.e., what is the incremental cost of the next better alternative?). Although the initial choice of cost allocation methods is typically made by the utility, regulators may choose to assume an active role in reviewing the cost allocation methods used and, where appropriate, requiring the use of methods that meet regulatory needs. Where a utility has filed a request for commission approval of a proposed reorganization or acquisition of an operating affiliate, the commission could prescribe beforehand the cost allocation methods to be used.

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[8]The utility may frequently use different methods for allocating different costs. For instance, the firm might use a direct charge method for allocating payroll and managerial costs and a formula method for allocating facilities overhead expenses.

Thereafter, the utility could periodically review its choice of allocation methods in light of changed circumstances (e.g., has the scope of the utility's nonregulated activities increased substantially in relation to the utility's regulated activities, or have the utility's accounting and information systems been improved--permitting the use of a preferable alternative method?).

Finally, as in the case of monitoring casual cost transfers, vigilant regulation of the allocation of common and overhead costs requires the use of periodic audits. Audits can be useful in detecting intentional and unintentional errors in the given allocation process. More importantly, the auditor can determine whether the cost allocation process is appropriate under the circumstances, or whether the company's existing informational systems could readily be adapted to support the use of a more appropriate cost allocation method.

Methods for Monitoring Diversified Utilities

Various efforts may be undertaken to improve the thoroughness of the regulation of diversified utilities. While the implementation of any of these methods may not be warranted in all cases, the commissions may wish to consider the implementation of at least some of these policies where this would be in the public interest. Thus some kind of cost-benefit analysis is involved. Clearly, if the costs of implementing a given measure outweigh the potential benefits, the measure should not be presently adopted. However, with ever increasing diversification activity on the part of electric utilities, a policy that is not cost-justified today may be in five or six years. Thus regulators may periodically reassess their cost-benefit appraisal in light of changed circumstances within their regulatory jurisdictions.

The policies which may be implemented to improve the regulation of diversified utilities fall into the following four categories:

* corporate restructuring audits
* audits
* affiliated interest filing requirements
* accounting & recordkeeping procedures

Each of these is discussed in turn.

Corporate Restructuring

A frequently cited rationale for permitting the formation of public utility holding companies and the spinning-off of unregulated diversified activities into separate subsidiary corporations is that such corporate reorganizations provide "greater separation of utility from nonutility operations." Thus when a utility derives a substantial portion of its income from nonutility activities, it may be advantageous for state regulatory officials to order the "spin-off" of the diversified nonutility activities into one or more separate subsidiaries. Such a corporate reorganization can be justified on the following grounds:

* It will result in greater separation of utility from nonutility operations.

* It will facilitate the regulatory process (since less staff time will be consumed in reviewing the corporation's nonutility activities).

The utility can also benefit from a "clean" separation of its utility and nonutility operations in a corporate reorganization. This is particularly true where the utility wants to avoid allegations of unfair competition in competitive markets through cross-subsidization by the utility's regulated activities. A "clean" separation of the firm's utility and nonutility operations also eliminates the need for management to employ complicated cost allocation procedures to divide operating revenues from nonoperating revenues in compliance with regulatory requirements. Similarly, the newly spun-off subsidiary derives tangible benefits from reduced compliance costs resulting from the need to comply with fewer regulatory reporting requirements. Separation of the subsidiary from the utility also enables the subsidiary to devise and implement its own accounting system, which would be better-suited to the unique informational requirements of its management than the Uniform System of Accounts.

As illustrated by the immediately preceding discussion, the separation of corporate entities, in and of itself, will not result in the minimization of unrecorded casual cost transfers. Where the resulting corporate structure would establish merely a legal separation of the two entities, i.e., separation in form but not in substance, regulators could expect to encounter the same kinds of difficulties with respect to unrecorded casual transfers as they would find had the utility remained a single legal entity. The major benefit to be derived from this type of legal separation is that it would result in separate accounting and bookkeeping by the utility and the subsidiary, and this would facilitate cost tracking and auditing procedures. However, this would not aid in detecting any unrecorded flows of funds from the utility to the subsidiary--which would escape the books altogether.

Where reorganizations have been requested by the utility, state commissions should satisfy themselves that the resulting corporate entities will, in fact, be separate. Thus, a commission may wish to permit reorganization, contingent upon the condition that the two corporate entities will occupy separate facilities and will be separately managed and staffed. The commission may also wish to seek assurances that intercompany transactions between the resulting corporate entities would be minimized--to the extent that this would not impinge upon a normal vendor-supplier relationship between the utility and its subsidiary. Thus where synergistic benefits can be derived by maintaining a vertically-integrated supplier-vendor relationship, as in the case of a captive coal mine, such transactions should be permitted since they are predicated upon the supplier-vendor relationship and not upon a parent-subsidiary relationship. For instance, a mining subsidiary would be expected to sell coal to its parent; however, the sale of computer-time from the parent to its subsidiary would not be predicated upon their vendor-supplier relationship and should therefore be discouraged or, at least, be given "special attention" on the part of regulatory authorities. Finally, in any instance where the utility files for commission approval of a proposed reorganization, the commission should predicate its approval upon assurances by the utility that the commission can have access to the subsidiary's books upon request.[9]

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[9]We recognize that some state commissions may not have the statutory authority to demand concessions of this type from the utility, thus obtaining through their conditioned approval additional authority and concessions that the commission would not otherwise have. The focus of this section is, however, on what are the preferable monitoring practices, not on what is currently permissable, given current legal constraints on commission authority.

Audits as a Tool in Monitoring Diversified Utilities

The use of periodic audits is perhaps the single most effective means of safeguarding the public interest with regard to diversified utilities. However, the single major drawback of auditing as a regulatory tool is its cost--either in terms of money (if an outside consultant is used) or in terms of commission staff time (if staff performs the audit or participates in the audit process). The extent to which a commission decides to rely on audits as a regulatory tool would depend on the potential benefits. Said another way, the commission needs to consider the extent of diversification and the potential for abuse (i.e., diversion of funds from the ratepayers to the utility's shareholders) in any given situation.

Developing an effective audit policy will involve consideration of the following issues: (1) targets, (2) frequency, (3) scope and objectives, and (4) implementation.

The first issue is targeting. A commission faced with a variety of utilities in its jurisdiction might wish to focus its efforts on the more diversified utilities, since this is where there is the greatest potential for abuse. A commission's audit policy needs to be flexible if the commission is to review and reasses its regulatory goals on a regular basis instead of tying itself down to a fixed and unchanging routine.

While in most cases it is probably not necessary for the commission to audit a subsidiary, in some cases this may be advisable. Such an instance would be where a utility and its subsidiary shared physical facilities or where a subsidiary's transfer prices are regulated on the basis of its or the utility's rate-of-return. In these cases, periodic audits of the subsidiary may be appropriate--assuming the commission can gain access to the subsidiary's books and facilities.

Related to the issue of which firms to audit is the issue of how regularly the audits should be performed. Here again, the commission would evaluate its own policies with respect to the nature of the utilities in its regulatory jurisdiction and consider such factors as the extent of diversification, the presence of shared facilities, the frequency and nature of affiliated transactions, and fuel procurement practices. Where a utility obtains a substantial portion of its fuel from affiliated suppliers (e.g., "captive" coal mines), a commission might require periodic audits focused primarily on the utility's fuel procurement practices and its transactions with subsidiaries--particularly where the utility's affiliated fuel contracts contain automatic fuel adjustment clauses.

A crucial issue for consideration is the objective or goal of the audit. In setting the objectives or goals for an audit program, regulators might choose to focus on those areas where the potential for abuse is greatest. The necessary scope of the audit will in turn be decided by these predetermined objectives or goals. Once again, the commission would want to avoid falling into a "pattern" in its approach to regulating diversified utilities. Rather, a commission might examine each diversified utility on a case-by-case basis. Thus, the goals and objectives for a given audit could be determined by the unique characteristics of a given corporate structure.

In developing its program, the commission may wish to consider the relative advantages of the following audit types: (1) comprehensive management audit, (2) reconnaissance audit, (3) fuel procurement practices audit, (4) executive management audit, and (5) affiliated transactions audit.

Although a large majority of the audits presently performed have been comprehensive studies, for purposes of monitoring problems related to diversification, a narrower, focused audit may be more cost effective. In general, however, the first commission-ordered examination of any utility would probably have a comprehensive scope. The comprehensive audit could identify major problem areas that can be examined in a second-stage focused study. In subsequent years, the audit can be focused on those specific areas identified in the original comprehensive audit.

An alternative approach for setting the scope of an audit--subsequent to the original comprehensive audit--is the use of a reconnaissance audit. The purpose of a reconnaissance audit is to identify those aspects of a company's operations requiring further study. Although a reconnaissance audit typically involves the same breadth of coverage (i.e., it does cover as many functional areas) as a comprehensive audit, it does not involve as much in-depth scrutiny in any one area. Because a reconnaissance study offers the strong assurance that no major problems have gone unnoticed and because it is less costly than a comprehensive audit, the combination of reconnaissance audits and subsequent focused studies can be useful in monitoring diversified utilities--particularly in periods when the firm's structure and operations are undergoing change.

Once the problem areas have been identified, the appropriate focused audits could be performed on a periodic basis. Although the pre-identified problem areas may vary with each utility, certain problem areas are typical to diversified electric utilities. Thus, an affiliate transactions audit will typically be appropriate whenever the utility engages in a significant number of transactions with its subsidiaries, and a fuel procurement practices audit may be needed whenever a utility purchases a substantial portion of its fuel from company-owned or controlled facilities.

Other types of focused audits may also be used in detecting and monitoring certain types of abuses associated with diversified operations. In particular, the corporate support services audit may be used to detect the presence of casual cost transfers, especially where there is a "close" working relationship between parent and subsidiary involving the use of common facilities.

Another area requiring special vigilance pertains to the allocation of managerial time and effort between utility and nonutility activities. The danger here is that the cost allocation basis selected by the utility may not accurately reflect the <u>value</u> of the executive's contribution to the utility's operations as opposed to that of the utility's diversified, non-regulated activities.[10] By carefully analyzing and focusing on managerial work product, an executive management audit will help to indicate whether the costs associated with managerial efforts are being properly allocated between a firm's utility and nonregulated operations.

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[10]Malko, Enholm, and Jaditz, "Energy Utility Diversification, Holding Companies and Regulation," pp. 27-28.

A final consideration for regulators is implementation of the audit, whether the audit should be performed by outside auditors, by commission staff, or some combination of staff and outside consultants. This choice will depend largely on the resources available to the commission---both financial and personnel. A related issue for consideration is the degree to which the auditor (staff or outside) is familiar with the operations of the entity being audited. For instance, commission staff may have considerably more expertise in electric utility operations than an outside auditor; on the other hand, for purposes of auditing a captive coal mining subsidiary, an outside auditor might have more knowledge and background concerning coal operations than would a commission staff member.

Commissions should avoid relying solely on outside consultants to perform the audits. By performing (or at least observing) the audits, commission accounting staff can become more familiar with a utility's accounting systems and operations (including potential problem areas) than they would by reading the auditor's report. Commission staff members may also be more likely to catch discrepancies or abnormalities than would an outside auditor.

On the other hand, reliance solely on commission staff to perform audits may also be inadvisable. The commission might occasionally hire outside consultants to perform the audits (using their own audit program), assisted by the commission's audit staff. This may possibly expose the commission staff to new insights and innovative approaches to the audit, which they may wish to incorporate in their own audit programs. It might also have the advantage of making the audit process less predictable (from the utility's point of view) and therefore more effective for regulatory purposes.

Affiliated Interest Filing and Preapproval Procedures

Affiliated interest filing requirements are another effective regulatory policy. Most states already require--either by statute or by commission order--the filing of all contracts between a utility and an affiliated corporate entity. The purpose of such filing procedures is to provide the commission staff with information concerning prices and contract terms in transactions between a utility and its subsidiaries. Affiliated interest filing requirements also serve the more general purpose of providing commission staff with information concerning the nature and frequency of the transactions between a utility and its subsidiaries and providing notice of potential problem areas. Since there is often no de minimis exception for these filing requirements,[11] affiliated interest filings (if enforced) will inform commissions of the full extent to which a utility's operations are interrelated with those of an unregulated affiliate. Since a large number of filings involving small dollar amounts tends to indicate a high degree of interrelatedness between the utility's operations and those of its subsidiary, this may serve as a "red flag"-- putting staff on notice about areas where there are also likely to be unrecorded casual cost transfers between the utility and its subsidiary. Such areas could be targeted as a focus for inquiry in subsequent audits. Similiary, a substantial number of affiliated fuel procurement contracts could indicate the need for a fuel procurement practices audit. Affiliated interest filing requirements are therefore a very useful regulatory tool for monitoring diversified electric utilities.

Affiliated interest contract preapproval procedures typically require that all contracts between a utility and an affiliate be filed with the commission before they are entered into. The contracts must then be reviewed and approved by the commission staff before they become effective; contracts not obtaining commission approval must be either revised (per commission instructions) or cancelled.[12]

Requiring preapproval of affiliated contracts appears to be an aggressive regulatory policy since it preempts any affiliate transactions which do not meet with commission approval. However, the actual usefulness

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[11]Unlike affiliated contract preapproval requirements, most affiliated interest statutes do not provide an exception for contracts involving insignificant dollar amounts; rather, all affiliated interest contracts must be filed, regardless of the amount involved.

[12]For example, see Wisconsin, Section 196.52, which is abstracted in appendix C.

of preapproval procedures depends on the extent of the commission's authority to regulate affiliate transactions. If the commission has the statutory authority to regulate the types of contracts (as opposed to just the contract terms) between utilities and affiliates (i.e., if the commission has the authority to disallow certain types of affiliate transactions), preapproval can be a useful regulatory tool, since the preapproval procedure could be used to disallow or preempt affiliated contracts not predicated on a well-established vendor-supplier relationship. The commission could disallow those affiliate transactions that are not economically justified (in terms of synergistic benefits predicated on the parent-subsidiary relationship). As a side benefit, the commission could thus reduce its overall regulatory load. The usefulness of the preapproval procedure for this purpose, however, is effectively limited to the evaluation of newly proposed contractual relationships between a utility and its subsidiary); once a contract is initially approved, a utility might expect that subsequent renewals of the same contractual relationship would be approved in the future.[13]

State commissions may sometimes lack the authority to regulate the types of transactions between utilities and subsidiaries, their authority being limited to approving or disapproving the terms of the affiliated contracts under review. Where the authority of the commissions is clearly restricted to merely approving or disapproving the price and/or terms of affiliated interest contracts, preapproval procedures would be less cost-effective as a regulatory device. In such cases, it might be argued that the same objectives could be accomplished through other, less costly

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[13]For this reason, a commission using preapproval may wish to have special procedures for filing, reviewing, and approving "first-time" affiliated interest contract filings. Filing regulations could require the utility to conspicuously denote "first-time" contracts as such at the time of filing so that these contracts would be earmarked for special consideration during the review process. By thus placing the burden of designating a "first-time" contract on the utility, the utility could be estopped from arguing justifiable detrimental reliance in a subsequent preapproval proceeding if it had previously failed to designate the contract as a "first-time" filing.

means.[14] Thus, where regulatory authority is clearly limited to passing on the contract terms, commissions might wish to carefully weigh the costs (especially in terms of staff time) of preapproval against any expected benefits to determine if the procedure is cost-justified or even necessary.

In addition to the tangible costs of preapproval, commissions might also consider the potential risks associated with preapproval procedures in general: the possibility of co-optation and the possibility of regulatory estoppel. The risk of co-optation is inherent in any preapproval procedure wherein the commission takes part in the utility's decision-making process: if the commission previously approves a decision on the part of the utility, it may be reluctant or unwilling at a later date to determine that the decision was, in fact, imprudent or unreasonable. Thus, in the context of affiliated interest preapproval, if a commission approves an affiliated interest contract, it may have a tendency to rely on its prior determination of reasonableness in a subsequent rate case; even if the commission were to reexamine these previously approved affiliated interest contracts in the course of the rate case, it might be reluctant to overturn

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[14]For instance, the objective of informing commissions concerning the nature and terms of affiliate transactions could be achieved through affiliated interest filing requirements, and the objective of assuring the reasonableness of costs incurred in affiliate transactions could be achieved by requiring careful review of affiliated contracts during a rate case. Contract preapproval--if performed effectively--might require the review of all previous preapproval requests and affiliated contracts for the utility in question. This could be a painstaking and time consuming process. Thus a preferable approach might be to require affiliated interest filing, but to review these contracts only in the course of a rate case. This could permit the thorough examination of all affiliated interest contracts in the course of a single, comprehensive review rather than on a case-by-case basis. A single review would not only be more efficient in terms of staff time, but trends and patterns would more likely be detected in a comprehensive review, than in a more piecemeal preapproval process. For a general discussion of preapproval procedures, albeit in a somewhat different context, see Russell J. Profozich et al., Commission Preapproval of Utility Investments (Columbus, Ohio: National Regulatory Research Institute, 1981).

its prior determination of reasonableness. Thus having sanctioned an affiliated interest contract, the commission may find itself (implicitly) bound by a prior decision which may have been made in a routine and perfunctory manner.[15]

Another related risk associated with preapproval procedures generally is regulatory estoppel. Regulatory estoppel may occur if a utility acts in reasonable reliance on a commission's determination in a preapproval proceeding; if the commission later withdraws its finding of reasonableness in a subsequent proceeding, the utility may estop the regulatory authority on equitable grounds, by showing that it acted in reliance on the commission's prior determination of reasonableness. However, because the reliance interests of the utility are typically not as great with respect to affiliated interest contracts, it can perhaps be argued that there is no danger of regulatory estoppel with respect to affiliated interest preapproval procedures. Nonetheless, this is a potential snag of which commissions should be aware: they might be legally bound by a determination of reasonableness made in a preapproval proceeding.

A preapproval procedure does have one significant advantage over an affiliated interest filing requirement, however. The preapproval procedure, when properly implemented, can more fully protect the ratepayers from both the direct and indirect adverse affects of potential imprudent (above-market rate) purchases, by a utility from its affiliate or subsidiary, by preventing the purchase from ever occurring. As noted earlier in this report in chapter 1, if a state commission has the power only to disallow from rates the expense of imprudent purchases after they occur, then the utility's financial position could become unsound. The only way to prevent such expenses from appearing in rates may be to prevent an imprudent purchase from ever occurring.

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[15]Since affiliated interest preapproval may become routine in nature, there is a risk that an overworked commission staff might perform their reviews without adequate investigation or review, thus rendering the preapproval process a mere formality.

To briefly summarize, affiliated interest filing requirements are a cost-effective and logical first choice for monitoring affiliate transactions. Preapproval procedures, on the other hand, may be far more costly to implement. Depending on the purpose for which it is used, preapproval may not be cost-effective, in comparison with alternative measures for regulating the price and terms of affiliated contracts. With any preapproval procedure there is the risk that the commission may later be bound--either through the effects of co-optation or by regulatory estoppel---by its finding of reasonableness in the preapproval process. Commissions using preapproval might therefore require that every request for approval be analyzed and reviewed in a thorough and systematic manner. However, a preapproval process might be the only method available that will assure that the cost of imprudent purchases does not end up in rates through the utility's cost of capital.

Accounting and Recordkeeping Procedures

A Uniform System of Accounts (U.S.O.A.) for electric utilities was promulgated by the National Association of Regulatory Utility Commissioners (NARUC) in 1936. The following year, the Federal Power Commission adopted the system for electric utilities under its jurisdiction and control.[16] With the exception of some minor revisions made in the 1950s and early 1960s, these same systems of accounts are used today.

The U.S.O.A., which is based on functional accounting concepts, is comprised of specific accounts in which all formal transactions are recorded at cost and--with a few exceptions--in accordance with generally

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[16]The FERC and the NARUC systems of accounts are similar, the major differences being the classification of certain advertising expense items and the interpretation of the accounts. A third uniform system of accounts is used by electrical cooperatives under the jurisdiction of the Rural Electrical Administration. See generally James E. Suelflow, Public Utility Accounting: Theory and Application (East Lansing: Michigan State University Press, 1973), chap. 3, and Robert L. Hahne and Gregory E. Aliff, Accounting for Public Utilities (New York: Matthew Bender & Company, 1984), chap. 11.

accepted accounting principles (G.A.A.P.).[17] The accounts were devised with the object of facilitating the regulatory process by state and federal agencies. Thus a key feature of the system is the segregation of the balance sheet accounts between utility and nonutility property for ready determination of rate base and non-rate base assets. Similarly, the income accounts are divided into operating income and other income account categories, for the ready determination of operating and nonoperating income by regulatory authorities. (These accounts are typically referred to as "above-the-line" and "below-the-line," respectively.) Although the U.S.O.A. may have been adequate for the informational needs of utilities and regulatory authorities in the 1930s and 1940s, many observers contend that they no longer provide sufficient information for either utility management or regulators in today's complex regulatory and nonregulatory environments.[18] Since the 1960s, utility managers confronted with unprecedented inflation rates, increasing environmental restraints and complex tax regulations, have faced serious informational constraints. In many cases, utility managers have responded to the need for improved information by developing and implementing complex dual-purpose accounting and reporting systems designed to meet the informational needs of management and at the same time satisfy their various regulatory reporting requirements.

There has been no such innovation on the part of regulatory authorities, and in today's complex regulatory environment the U.S.O.A. is no better suited to the informational needs of contemporary regulatory agencies than to the needs of utility managers. The possible inadequacy of the

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[17]The major differences between accounting under the U.S.O.A. and under G.A.A.P. relates to the timing of when various items enter into the determination of net income in accordance with the principle of matching expenses and revenues. See generally Financial Accounting Standards Board, Statement No. 71: Accounting for the Effects of Certain Types of Regulation (Stamford, Conn.: Financial Accounting Standards Board, 1982).

[18]See generally Hahne & Aliff, §15.02. See also, Serge Matulich and Charles M. Becker, "Regulatory Accounting Problems Facing Public Utility Managers," Public Utilities Fortnightly, December 22, 1983, pp. 30-34.

U.S.O.A. in regulating diversified electric utilities was recognized by the NARUC Ad Hoc Committee on Utility Diversification in its 1982 report.[19]

One example of how regulators face informational constraints with the U.S.O.A. is in the area of cost allocation. Since the U.S.O.A. does not require the maintenance of cost data on a functional cost center basis, utilities (and thus regulators) typically lack the necessary data to allocate overhead costs between regulated and nonregulated activities on a functional basis. Utilities (and regulators) lacking this kind of information must resort to other, less precise, cost allocation methods such as the application of overall (firm-wide) formulas.

Another problem for regulators is posed by the aggregation of accounts relating to transactions with affiliated companies. A list of accounts pertaining to affiliated transactions appears in table 5-2. Of the nine accounts listed, seven are balance sheet accounts. The only two accounts appearing on the utility's income statement are account 418.1 ("Equity in Earnings of Subsidiary Companies") and account 430 ("Interest on Debt to Associated Companies"). Since there are no separate income/expense accounts for payments to/from subsidiaries in affiliated transactions, these expenses or revenues are recorded in the utility's functional revenue/expense accounts, along with expenses/revenues paid/received in arms-length transactions with nonaffiliated entities. Thus, the aggregate amounts of payments and receipts from subsidiaries are "buried" in the functional income and expense accounts. The end result is that the utility's financial statements have little useful informational content for regulatory authorities. Under the current system of accounts, information useful in regulating affiliated transactions can only be obtained in the course of an in-depth review of the utility's books--which is both costly and time consuming.

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[19]National Association of Regulatory Utility Commissioners, 1982 Report of the Ad Hoc Committee on Utility Diversification (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1982), p. 82.

TABLE 5-2

U.S.O.A. ACCOUNTS PERTAINING TO
AFFILIATED ENTITIES

Account Number	Account Title
	Balance Sheet Accounts
123	Investment in associated companies.[1]
123.1	Investment in subsidiary companies.[2]
145	Notes receivable from associated companies.
146	Accounts receivable from associated companies.
223	Advances from associated companies.
233	Notes payable to associated companies.
234	Accounts payable to associated companies.
	Income Accounts
418.1	Equity in earnings of subsidiary companies.
430	Interest on debt to associated companies.

Source: 18 C.F.R. Part 101 (1984)

[1]"Associated (affiliated) companies" means companies that "directly or indirectly...control, or are controlled by...the accounting company." ..."Control" means "the possession, directly, or indirectly, of the power to direct or cause the direction of the management and policies of a company...."

[2]"Subsidiary companies" means companies which are controlled by the utility through ownership of voting stock.

Because of the recent activity in electric utility diversification, this problem has again attracted the attention of regulators in the accounting field whose time and attention have been to some extent preoccupied with the revision of the U.S.O.A. for telephones. To date, therefore, little time and attention has been given to the issue of the adequacy (or inadequacy) of the U.S.O.A for regulating diversified electric utilities and the possible means (if needed) for enhancing the informational content of existing accounting systems using the U.S.O.A.

One possible solution, which is presently under consideration by the California Public Utilities Commission staff, would be to require the use of a separate clearing account for all transactions with affiliates, as well as common cost allocations. This account would be divided into various subaccounts classified according to some consistent methodology (e.g., expense type, affiliated payee, etc.). By accumulating all information pertaining to affiliated transactions in one centralized location, classified in a consistent and meaningful way, the clearing account would greatly facilitate the auditing and tracing of various costs (both transfer costs and common costs) associated with the utilities' subsidiaries.

An alternative approach--along a similar vein--would be to require utilities to journalize all transactions with subsidiaries in a single, consolidated monthly entry, thereby reducing the time necessary to locate individual entries and expense items in the course of an audit.

Finally, for purposes of quick review, the commission could require the filing of supplemental schedules pertaining to affiliate transactions. Such filings could contain lists of expenditures by supplier, by expense account, or by any other classification useful to the commission staff. This method, while more subject to manipulation, omission and clerical errors--and hence not reliable--would provide staff with summary information to be used as the basis for subsequent in-depth review or desk audits of the utility's books. If proven reliable on the basis of the prior year's audits, such information could be used as a basis for decisionmaking in subsequent proceedings.

CHAPTER 6

ESTIMATING THE COST OF CAPITAL

Thus far, this report has dealt with problems associated with affiliate transactions such as transfer pricing, cross subsidization, and common cost allocation. An additional difficulty, addressed in this chapter, is that estimation of a company's cost of capital becomes complicated if the company has equity interests in other companies or if its equity is owned by other companies. Hence, if an electric company has subsidiaries or is itself owned by a parent company, its cost of capital most likely will be difficult to separate from that of the associated companies. The reason is that the separate companies do not issue equity; instead, a single entity, either a holding company or the parent company, issues all common stock.

The issue of estimating the cost of equity in such cases has been associated historically with holding companies and the regulatory experience with the American Telephone and Telegraph system, in particular. The difficulties associated with estimating the cost of equity are essentially the same for holding companies and for regulated utilities that own subsidiaries. In the latter case, the utility usually does not issue debt on behalf of a subsidiary, which is conceptually similar to a holding company that is 100 percent equity financed. Most of the literature about this subject has been written in the context of holding companies. The discussion in this chapter is framed in terms of holding companies also, partly to be consistent with the existing literature, and partly because no special treatment of the strict subsidiary structure is needed since this is financially similar to a 100 percent equity-financed, holding company. The discussion of holding companies in the chapter, then, is a natural consequence of the subject matter and is not a departure from the narrow focus on subsidiaries taken elsewhere in this report. Note also that the term holding company pertains to organizations other than those that hold several operating electric companies. As discussed in chapter 1, several electric utilities have adopted a holding company format for a single electric company and associated affiliates such as fuel supply or transportation companies. In such cases, the term "holding company" is an accurate description of the corporate struture, but it falls within this report's scope nonetheless.

Because the holding company or the parent electric company issues all common stock, the market return on this equity, which is observable or at least can be estimated from market data, reflects some kind of amalgamation of differing returns on equity. Disentangling the separate components from the observable market return generally requires information in addition to that about the parent company's return on equity. In practice, it is usually only the equity portion of a regulated utility's capital structure for which this ambiguity exists. Typically, debt is issued by individual operating companies, or subsidiaries, and hence the cost-of-debt portion of a company's weighted average cost of capital is known with some certainty.

Two general approaches are taken in the regulatory community to the estimation of the cost of capital in such circumstances. These can be generally described as those that rely on comparisons to similar, regulated companies and those that depend on some variation of a double leverage method. Most of this chapter is devoted to a discussion of the double leverage methods. This emphasis springs not so much from an admiration of these methods, as it does from our perception that double leverage is imperfectly understood. The intent, here, is to explain the various double leverage concepts clearly using a somewhat novel perspective. The need for a similar description of risk-comparison techniques in this report is not nearly so great, partly because such comparative methods are well understood among state commission financial analysts, partly because the issue is quite general and is not raised specifically by the topic of this report, and partly because these techiques have been discussed thoroughly elsewhere.[1] Consequently, the discussion of these comparative methods is limited to broad distinctions that can be drawn between them and double leverage techniques.

The terminology "double leverage" refers to a financial arrangement whereby one company purchases the common equity of another with funds consisting partly of equity and partly of debt. Hence, the operating company is levered once by the issuance of its own debt, and levered for a second time, in effect, by the parent's debt issue. The technique is most commonly used when one company holds the common stock of more than one operating company.

The double leverage method of determining the cost of capital can be narrowly defined as one that "prescribes the use of the cost of total capital (the composite cost of debt and equity) to the parent company as the measure of the cost of common equity to the operating subsidiary."[2] A somewhat broader perspective is taken in this chapter where the double leverage concept is interpreted as including any method of estimating the cost of capital that is based on the returns on a parent company's assets.

The viewpoint taken in this chapter is to question whether or not double leverage techniques provide good estimates of an operating subsidiary's cost of capital. The emphasis is on the quality of the estimation. This viewpoint is central to understanding double leverage concepts. A substantial amount of confusion and controversy in the literature, in our opinion, can be traced to attempts to place the discussion in an equity framework. For example, the Public Utilities Fortnightly reported that one state commission supports the double leverage method since "to ignore the effect of debt-equity leverage at the parent

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[1]See, for example, Charles River Associates, Methods Used to Estimate the Cost of Equity Capital in Public Utility Cases: A Guide to Theory and Practice, (Boston: Charles Rivers Associates, March 1982).

[2]See Charles F. Phillips, Jr., The Regulation of Public Utilities (Arlington, VA: Public Utilities Reports, 1984).

level would result in a windfall return of GTE's stockholders."[3] In an early article, Brown characterizes public utility commissions' arguments in favor of double leverage as "Why indeed should the customers of one company help pyramid the earnings of the stockholders in another company simply because of a financial arrangement over which these customers have no control? And should not this be particularly offensive in the case of public utilities whose primary objective is to provide adequate public utility services at fair prices?"[4]

This emphasis on social equity has tended to focus the discussion away from the central issue which is the extent a parent company's observable (or at least estimable) cost of equity capital can be useful in estimating a subsidiary's unobservable cost of equity. Skipping ahead to the end of this chapter, the conclusion is that such estimates are fundamentally flawed and almost certainly have errors in practice. The estimation errors, however, are not necessarily so large as to make the concept useless, especially if combined with other market-based estimates. It is always good to recall that all cost of capital methods yield only estimates, about which there is some uncertainty. In this context, double leverage methods can serve as useful benchmarks that the financial analyst may wish to consider along with other independent estimates.

The chapter has four sections. In the first, some fundamental financial equilibrium conditions are described and suggestions made about ways to combine such conditions with independent equity cost estimates in order to unravel a holding company's observed equity return into its component parts. The properties of four double leverage methods are discussed in the second section, which is presented from the viewpoint of estimation. With this perspective, a brief literature review is presented in the third section to illustrate a few ways that controversy has arisen. Some brief conclusions are in the last section.

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[3]Public Utilities Fortnightly, August 2, 1984, p. 55 reporting on General Telephone Co. of the Southeast, Docket No. U-83-7247, February 21, 1984.

[4]James E. Brown, "Double Leverage: Indisputable FACT or Precarious THEORY?", Public Utilities Fortnightly, May 9, 1974, pp. 26-30.

Financial Equilibrium and Market-Based Comparison Methods

To make the discussion manageable, issues regarding a firm's optimal capital structure are ignored, for the most part. The optimal amount of debt and equity is not a topic that financial analysts have solved either in theory or in practice. With this abstraction, consider a firm with $1000 in assets, financed entirely by equity, and no taxes.[5] Suppose its required rate of return on its assets is 12 percent. Equity owners earn 12 percent. If instead, this firm were financed by $500 of equity and $500 of 9 percent debt, the required return to the assets is still 12 percent. Nothing has changed in the firm's risky economic environment, so 12 percent is still the required overall return. The existence of the superior claim of bondholders, however, means the equity owners must now earn 15 percent. The weighted average of the 9 percent bonds and 15 percent equity returns is the required overall return of 12 percent. This is the fundamental financial equality that is enforced by the market. Stated differently, this equality requires that the weighted average cost of capital must be equal to the required return on the assets. The overall return is affected by the company's operating risk, whereas the return to equity is affected in addition by the financial leverage chosen by management.

A corollary to this fundamental financial equality is that a parent company's overall rate of return is a weighted average of the returns on all the assets it owns. If it owns the equity in two or more subsidiaries, its overall rate of return equals a weighted average of the equity costs of its subordinate operating companies. This corollary is true for the nondiversifiable portion of each subsidiary's risk premium. That is, financial theory holds that observed risk premiums for publicly traded companies have already been purged of any diversifiable components by the action of investors in creating optimal portfolios. The remaining,

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[5]The assumption of no taxes makes the exposition easier, but could be relaxed with no important consequences to the presentation here.

observable, portion has the property that required returns for combinations of companies can be found as a weighted average of the individual company returns. No synergistic effect, that is, nothing better than this weighted average, is possible because investors have already exhausted such possibilities. A holding company can improve upon the market average if some real economic advantage is involved, but not by merely combining the finances of two companies.

Because of this second financial equilibrium condition, the weighted average cost of capital of the holding company can be expressed as

$$\sum_i \frac{E_i}{T_p} e_i = C_p$$

$$= \frac{D_p}{T_p} r_p + \frac{E_p}{T_p} e_p \qquad (1)$$

where the subscript i refers to subsidiary i, and p to the parent company,

E_i is the value of equity for subsidiary i,

T_p is the total value of the parent company,

D_p is the value of the parent company's debt,

r_p is the parent company's percentage cost of debt,

e_i is the percentage cost of equity for subsidiary i, and

C_p is the parent company's weighted average cost of capital.

Note the assets of the parent company consist of the equity values of its subsidiaries, hence the simple accounting identity $\sum E_i = T_p$ must be true. Consequently, the left hand side of equation (1) is a weighted average of the equity costs of the subsidiaries. This means that

$$\sum w_i e_i = C_p \qquad (2)$$

where w_i is the fraction of the parent company's value represented by the equity of subsidiary i.

Financial analysts at state commissions use a variety of methods to estimate equity costs. These include discounted cash flow, the capital asset pricing model, comparable risk, and so on. Generally speaking, any such method could be used to estimate the equity cost of the holding company. Whichever method or methods are chosen, the parent company's weighted average cost of capital, C_p, then can be found using equation (1). The subsidiaries' equity costs, e_i, in equation (2), however, can not be estimated directly from such market data. Instead, two general strategies could be followed to estimate a particular e_i, say e_1. First, the analyst could use a comparable company for which market data are available and infer e_1 from the estimate of the comparable equity cost. Second, the analyst could find comparable equity costs for all subsidiaries other than e_1. With estimates of e_2, e_3, and so on, equation (2) could be used to estimate e_1 since the analyst has estimated the parent's weighted average cost of capital as well as the equity costs of all subsidiaries other than the regulated utility. Either or both of these methods could be used to provide information about a particular subsidiary's equity costs. For that matter, either could be used routinely to check the consistency of the estimates made using the other method.

The second method, in practice, may add little to the analyst's arsenal of financial estimation tools. If the electric company's equity cost can be estimated indirectly by comparison with similar electric utilities, the incremental value of estimating the equity cost of a real estate enterprise, for example, and then using this to unravel C_p in equation (2) may be quite small. The purpose here is to point out the nature of the problem, which is that the observed return to the parent company somehow must be disaggregated into its component parts. Independent, market-based information for all but one of the subsidiaries could be combined with equation (2) to estimate the equity cost of the remaining one.

Estimation Properties of Four Double Leverage Methods

Double leverage methods use a quite different basis to estimate the equity cost of a subsidiary. No information outside of the parent and its subsidiaries is brought to bear. As we shall see, without such information equation (2) cannot be successfully solved, having as it does more than one unknown value. To demonstrate this point, the fundamental financial equality and its corollary are used extensively in this section. The argument is presented by means of hypothetical examples. Each example obeys the requisite financial market equilibrium conditions. The issue then becomes how well the various double leverage methods estimate a subsidiary's unobservable cost of equity. The rudiments are presented in table 6-1 for a holding company, the parent, with a single subsidiary.

TABLE 6-1

A SINGLE SUBSIDIARY

	Cost of Capital (%)	Capital Structure		
		Consolidated Company	Operating Subsidiary	Parent
Debt-Parent	10	$25		$25
-Subsidiary	10	50	$50	
Equity-Parent	18	25		25
-Subsidiary	14	--	50	--
		$100	$100	$50
Weighted Ave Cost of Capital (%)	$\uparrow$	12 $\xrightarrow{\text{Method 2}}$	12	14
	$\xleftarrow{\text{Method 1}}$			

Source: Authors' calculations.

In table 6-1, an operating company, in the column labeled operating subsidiary, with $100 of assets issues $50 of debt at 10 percent and $50 of equity that earns 14 percent. Its weighted cost of capital is 12 percent. This company's equity is then purchased by a parent company. The parent issues $25 of debt and $25 of its own common stock. Only the parent's cost of equity, then, can be observed. That is, once the operating company is purchased by the parent, the operating company's common stock is no longer publicly traded and, hence, neither the 14 percent equity cost of the subsidiary nor its 12 percent overall cost of capital can be observed or estimated directly. These two numbers, 12 and 14 percent, have been circled in the table to denote that they are not observed in the market. We wish to estimate these costs, however.

Two indirect estimation methods, proposed in the literature, can be illustrated with this example. (Two others, described later, require a more complicated example and can not be illustrated with this one.) The first is the "Equity Cost Assignment" (ECA) method. The 18 percent return on the parent's equity can be estimated from market data. Averaged with its 10 percent debt, the parent's overall cost of capital can be estimated as 14 percent. The cost-of-equity assignment method assigns this 14 percent as the subsidiary's otherwise unobservable cost of equity, which is then averaged with the subsidiary's 10 percent debt cost to deduce the overall operating rate of return as 12 percent. This is the most commonly used double leverage technique. It is doubly levered because the parent's 50/50 leverage, in effect, is relevered again when accounting for the debt-equity ratio of the subsidiary. When there is only one subsidiary, the cost-of-equity assignment correctly estimates the subsidiary's capital costs.

A second technique is the "Capital Cost Assignment" (CCA) method. In this case, the capital structure of the consolidated parent-subsidiary company is used to find the consolidated, weighted average cost of capital (WACC). As before, market data are used to estimate the cost of the parent's equity as 18 percent. The consolidated company has $75 of debt, $50 from the operating company and $25 from the parent, and $25 of equity. The weighted average of these costs is 12 percent. This overall, consolidated rate of return is assigned directly as the subsidiary's cost of capital. After this assignment is made, the subsidiary's equity cost can be inferred as 14 percent by reversing the arithmetic in the weighted average cost of capital formula. This second method of estimation is also correct when there is only one subsidiary.

These two cost assignments are the only two which are consistent with the fundamental financial equality. Most of the early controversy regarding double leverage can be traced to cost assignments that were not compatible with this market equilibrium condition. A brief elaboration of this point appears in the next section. Even more briefly, it would not be consistent with market conditions, for example, to assign the parent's 18 percent equity cost as the subsidiary's cost of equity. The opposite assignment, of the subsidiary's equity cost (perhaps estimated from market data on independent, similar operating companies, although this is not clearly explained by those authors who have made this error) to the parent is equally inconsistent with market conditions. Importantly, the cost of equity of the parent differs from and is usually higher than that of its operating companies. The reason is the parent's equity owners realize their investment is more risky, standing in line, as it does, behind the debt claims of both the operating and parent companies' bondholders. This simply reflects that the return to equity, in part, is based on financial risk which is, in turn, influenced by the degree of leverage.

Both double-leverage, cost-assignment methods provide good estimates of a subsidiary's cost of capital, consistent with market equilibrium, when the parent holds a single operating company. In reality, holding companies almost always have more than one subsidiary. With two or more subsidiaries, the issues become slightly more complicated and in addition, there are two other methods that can be used to estimate the cost of capital. In both of these, an artificial capital structure is first imputed to a subsidiary which is then used to compute a cost of capital. These imputed capital structures are illustrated in tables 6-2 and 6-3.

Table 6-2 shows the first step of the "Consolidated Capital Structure Assignment" (CCSA) method.[6] The example in the table has two subsidiaries each with $100 of assets, but differing amounts of debt. The total equity

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[6]This method is described by William L. Beedles, "A Proposal for the Treatment of Double Leverage," Public Utilities Fortnightly, July 5, 1984, pp. 31-36.

TABLE 6-2

THE CONSOLIDATED CAPITAL STRUCTURE ASSIGNMENT METHOD

	Consolidated Company	Subsidiary 1 Actual	Subsidiary 1 Inferred	Subsidiary 2 Actual	Subsidiary 2 Inferred	Parent
Debt-Parent	$50		$12.5		$37.5	$50
-Subsidiary 1	50	$50	50			
-Subsidiary 2	25			$25	25	
Equity-Parent	75					75
-Subsidiary 1		50	37.5			
-Subsidiary 2				75	37.5	
	$200	$100	$100	$100	$100	$125

Source: Authors' calculations.

TABLE 6-3

THE PROPORTIONAL CAPITAL STRUCTURE ASSIGNMENT METHOD

	Consolidated Company	Subsidiary 1 Actual	Subsidiary 1 Inferred	Subsidiary 2 Actual	Subsidiary 2 Inferred	Parent
Debt-Parent	$50		$20		$30	$50
-Subsidiary 1	50	$50	50			
-Subsidiary 2	25			$25	25	
Equity-Parent	75					75
-Subsidiary 1		50	30			
-Subsidiary 2				75	45	
	$200	$100	$100	$100	$100	$125

Source: Authors' calculations.

of both companies is $125 which is owned by a parent that has issued $50 of debt. The consolidated company has $75 of equity and $200 total value. The CCSA method imputes the consolidated company's fraction of equity to each subsidiary, which is 37.5 percent in this case. This inference usually reduces the apparent amount of equity in each operating company. The parent's debt is next allocated to each subsidiary so as to keep the total capital of each the same. The next step, not shown in table 6-2, is to calculate a weighted average cost of capital (WACC) using the inferred capital structure, substituting the parent's cost of equity for the unobserved equity cost of the subsidiary. The results of this next step are described after first introducing the second method of this genre.

A fourth, and final, technique may be called the "Proportional Capital Structure Assignment" (PCSA) method.[7] In this technique, the equity of each subsidiary is reduced such that the aggregate, inferred equity equals that of the parent, and also such that the proportion of inferred to actual equity of each subsidiary is the same. In table 6-3, the example shows subsidiary 1 with $50 out of $125 of total equity, or 40 percent. The inferred capital structure reduces the aggregate equity from $125 to $75 and assigns 40 percent of this to the first subsidiary, the remaining 60 percent to the second. As before, the parent's debt is assigned to each operating company so as to keep the total capitalization constant. The computation of the weighted average cost of capital proceeds as before.

Reviewing briefly, there are four methods of estimating a subsidiary's cost of capital based on the observed market performance of a parent company's common stock. Two of these assign capital costs and two are based on an assignment of capital structure. These can be called the equity cost assignment method (ECA), the overall capital cost assignment method (CCA), the consolidated capital structure assignment method (CCSA), and the proportional capital structure assignment method (PCSA). The

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[7]This method has not been formally introduced in the literature. It is not novel, in the sense that it is implicit in several reported rate cases and court decisions. The discussions here, however, may be the first explicit, analytical treatment of it.

purpose here is to evaluate how well each of these four methods estimates a subsidiary's capital costs. The strategy employed is to present four hypothetical examples of a parent company owning two subsidiaries. These are shown in tables 6-4, 6-5, 6-6, and 6-8. Each example has been constructed so as to obey the fundamental financial market equilibrium conditions. In each, the subsidiaries' cost of equity and overall cost of capital are not directly observable. To remind the reader of this, each of these numbers has been circled in the tables. The four examples differ in the relative riskiness of the two subsidiaries.

The first example is presented in table 6-4. It illustrates how each of the four double leverage methods estimates the cost of capital if the operating risk of the two subsidiaries is the same. Hence, the weighted average cost of capital of the two operating companies is assumed to be 13 percent in table 6-4. From this, the unobserved equity cost of each can be deduced. Financial equilibrium requires that the parent company's overall cost of capital equal the weighted average of these component equity costs. In table 6-4, the parent's 15 percent overall return equals the average of 16 and 14.34 percent, using the respective equities as weights. Also, the equilibrium market conditions require that the consolidated company's overall cost be a weighted average of the subsidiaries' overall costs of capital. Since each subsidiary has a weighted average cost of capital (WACC) of 13 percent, this requires that the consolidated company's WACC be 13 percent also, which it is.

The estimated WACC and equity cost from each of the four double-leverage methods are listed in table 6-4. The capital cost assignment (CCA) method naturally is a perfect predictor because the example has been arranged to have equal WACC's for each operating company. Using the consolidated company's WACC to estimate the unobserved subsidiaries' WACCs is precisely the correct thing to do in such circumstances. This estimation takes advantage of one of the two financial market equilibrium conditions. The remaining three methods all have some error. It is not obvious from the example, but the consolidated capital structure assignment (CCSA) method is very similar to the capital

TABLE 6-4

EQUAL OPERATING RISK: FOUR DOUBLE-LEVERAGE METHODS

	Cost of Capital (%)	Capital Structure			
		Consolidated Company	Subsidiary 1	Subsidiary 2	Parent
Debt-Parent	12	$50			$50
-Subsidiary 1	10	50	$50		
-Subsidiary 2	9	25		$25	
Equity-Parent	17	75			75
-Subsidiary 1	16		50		
-Subsidiary 2	14.34			75	
		$200	$100	$100	$125
Weighted Ave. Cost of Capital (%)		13	13	13	15
Estimated Cost of Capital (%):					
Equity cost assignment (ECA)			12.5	13.5	
Capital cost assignment (CCA)			13.0	13.0	
Consolidated structure assignment (CCSA)			12.875	13.125	
Proportional structure assignment (PCSA)			12.5	13.5	
Estimated Equity Cost (%):					
Equity cost assignment (ECA)			15.0	15.0	
Capital cost assignment (CCA)			16.0	14.34	
Consolidated structure assignment (CCSA)			15.75	14.5	
Proportional structure assignment (PCSA)			15.0	15.0	

Source: Authors' calculations.

cost assignment (CCA) method. The estimates differ only to the extent that the debt costs of the parent and subsidiaries differ. If all debt had the same cost, the CCSA and CCA estimates would be identical. The originator of the CCSA method, Professor Beedles, used such an example in his exposition of the method.[8] Since his example also had equal operating risks, as is the case for the example in table 6-4, he would have obtained the correct estimates by using either the simpler CCA method or his CCSA method. His proposed CCSA method has no advantage over the CCA method, and indeed provides incorrect estimates when debt does not cost the same for all companies, as illustrated in table 6-4.

The remaining two estimation methods are inaccurate in the example illustrated in table 6-4. Both the equity cost assignment (ECA) method and the proportional capital structure assignment (PCSA) method estimate the cost of capital to be 12.5 percent for subsidiary 1 and 13.5 percent for the second. In general, these two methods always provide the same estimates. In effect, both of these methods use the parent company's WACC as the estimate of the subsidiaries' equity costs, which is 15 percent as shown in table 6-4. Since both use the same equity cost estimate, the estimated WACCs are also the same, of course. Whenever the unobserved equity costs of the subordinate operating companies differ from one another, both the ECA and PCSA methods will provide inaccurate estimates. Note that using the parent's WACC to estimate the subsidiaries' equity costs is not fundamentally wrong. In some sense, the idea is traceable to one of the fundamental financial market conditions described previously. The difficulty is that the market conditions require that a weighted average of subordinate equity costs equal the parent's WACC. The individual component equity costs are not observable, whereas the parent's WACC is observable. It is not possible, generally, to infer the components on the basis of the observed aggregate. Hence, there is no way of inferring the relative riskiness of the operating companies from information solely about the parent company.

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[8]See Beedles, "A Proposal for the Treatment of Double-Leverage," pp. 31-36.

If, by coincidence, the equity costs of the various subsidiaries happened to be the same, then the ECA and PCSA methods provide accurate estimates. These circumstances are illustrated in table 6-5. Since the equity costs are the same for each operating company and since each has different debt costs and leverage, the overall WACCs for each subsidiary are now different from one another. Since the capital cost assignment (CCA) method allocates the consolidated company's WACC to each operating company, it naturally is inaccurate in the current circumstances. The consolidated capital structure assignment (CCSA) method, as before, provides estimates that are quite similar to the CCA method, and hence it also is inaccurate. Fortuitously, the CCSA estimates are slightly better than those of the CCA method, in the example shown in table 6-5. This is not generally true, however. The difference between the two methods will sometimes work in favor of one or the other, depending on the direction of the relative riskiness of the two operating companies.

Table 6-6 shows the four sets of estimates that emerge from an example in which the two operating companies have different riskiness, both when measured by equity costs and also by the respective WACCs. All four methods are incorrect. It happens that the equity cost assignment (ECA) method and its equivalent, the proportional capital structure assignment (PCSA) method, provide slightly superior estimates. This will not generally be true, however. There is no way of knowing which method will be more accurate, in general.

Apart from numerical examples, some insight about the four double leverage methods is gained by expressing the estimated value of the equity cost in terms of information observable in the market. Table 6-7 summarizes the results of this algebraic exercise. The first formula in table 6-7 shows that the equity cost assignment (ECA) method estimates a subsidiary's equity cost in a manner similar to that of a Capital Asset Pricing Model (CAPM) formula. In particular, the ECA and PCSA methods estimate an operating company's cost of equity as the parent company's debt cost plus some fraction of the risk premium associated with the parent's equity cost. This risk premium is the difference between the

TABLE 6-5

EQUAL EQUITY RISK: FOUR DOUBLE-LEVERAGE METHODS

	Cost of Capital (%)	Capital Structure			
		Consolidated Company	Subsidiary 1	Subsidiary 2	Parent
Debt-Parent	12	$50			$50
-Subsidiary 1	10	50	$50		
-Subsidiary 2	9	25		$25	
Equity-Parent	17	75			75
-Subsidiary 1	15		50		
-Subsidiary 2	15			75	
		$200	$100	$100	$125
Weighted Ave. Cost of Capital (%)		13.0	12.5	13.5	15.0
Estimated Cost of Capital (%):					
Equity cost assignment (ECA)			12.5	13.5	
Capital cost assignment (CCA)			13.0	13.0	
Consolidated structure assignment (CCSA)			12.875	13.125	
Proportional structure assignment (PCSA)			12.5	13.5	
Estimated Equity Cost (%):					
Equity cost assignment (ECA)			15.0	15.0	
Capital cost assignment (CCA)			16.0	14.34	
Consolidated structure assignment (CCSA)			15.75	14.5	
Proportional structure assignment (PCSA)			15.0	15.0	

Source: Authors' calculations.

TABLE 6-6

UNEQUAL RISKINESS: FOUR DOUBLE-LEVERAGE METHODS

	Cost of Capital (%)	Capital Structure			
		Consolidated Company	Subsidiary 1	Subsidiary 2	Parent
Debt-Parent	12	$50			$50
-Subsidiary 1	10	50	$50		
-Subsidiary 2	9	25		$25	
Equity-Parent	19.67	75			75
-Subsidiary 1	14		50		
-Subsidiary 2	18.33			75	
		$200	$100	$100	$125
Weighted Ave. Cost of Capital (%)		14	12	16	16.6
Estimated Cost of Capital (%):					
Equity cost assignment (ECA)			13.3	14.7	
Capital cost assignment (CCA)			14	14	
Consolidated structure assignment (CCSA)			13.875	14.125	
Proportional structure assignment (PCSA)			13.3	14.7	
Estimated Equity Cost (%):					
Equity cost assignment (ECA)			16.6	16.6	
Capital cost assignment (CCA)			18	15.67	
Consolidated structure assignment (CCSA)			17.75	15.83	
Proportional structure assignment (PCSA)			16.6	16.6	

Source: Authors' calculations.

TABLE 6-7

FORMULAS FOR THE COST OF EQUITY ESTIMATES
OF FOUR DOUBLE LEVERAGE METHODS

Method	Cost of Equity Formula
Equity Cost Assignment (ECA)	$\hat{e}_i = r_p + \frac{E_p}{T_p} (e_p - r_p)$
Capital Cost Assignment (CCA)	$\hat{e}_i = r_p + \frac{E_p/T_c}{E_i/T_i} (e_p - r_p) + \left\{ \frac{D_i}{E_i} (r_p - r_i) + \frac{T_i}{E_i} \left(\frac{\Sigma D_i r_i}{T_c} - \frac{\Sigma D_i r_p}{T_c} \right) \right\}$
Consolidated Capital Structure Assignment (CCSA)	$\hat{e}_i = r_p + \frac{E_p/T_c}{E_i/T_i} (e_p - r_p)$
Proportional Capital Structure Assignment (PCSA)	$\hat{e}_i = r_p + \frac{E_p}{T_p} (e_p - r_p)$

Notation: e_i is the cost of equity capital for subsidiary i,

$\hat{e}_i$ is the estimated value of e_i,

T_p is the parent company's total value, including both debt and equity, and the subscript i refers to subsidiary i, p to the parent company, and c to the consolidated company.

r_p is the parent company's percentage cost of debt, and

E_p is the parent company value of equity,

Source: Authors' calculations.

parent's equity and debt cost, which is multiplied by a factor that depends on the parent's leverage. The factor is the fraction of equity in the parent company's capital structure. This formula is not, in reality, consistent with the CAPM formulation of a riskless interest rate plus a Beta coefficient times the market risk. A leverage factor consisting of a parent company's equity divided by its total value, E_p/T_p, does not measure risk relative to that of the overall market, as does the CAPM. Also, the formula makes clear that equity cost is estimated to be the same for all subsidiaries, regardless of their relative riskiness. Despite these drawbacks, and these are quite serious, the formula may be useful if the various subsidiaries have about the same riskiness or if this estimate is combined with other market information about comparable companies.

The formula for estimating equity cost by Professor Beedles' consolidated capital structure assignment (CCSA) method, in table 6-7, has a structure similar to that of the ECA and PCSA methods. The only difference is that the leverage coefficient is more complicated, and now depends on subsidiary-specific information. The coefficient is the ratio of two equity fractions. The numerator is the fraction of equity in the entire corporate structure, that is the consolidated company. The denominator is the fraction of equity on a particular subsidiary's books. This ratio of two equity fractions may be smaller or greater then unity, although it happens to be smaller than one in the example used in tables 6-4 to 6-6. The construction of the leverage fraction implies that the CCSA method estimates a lower equity cost for subsidiaries with higher equity fractions. The example in table 6-6 confirms this. It is tempting to interpret this as sensible since companies with more equity have less financial risk and consequently should have lower equity costs. This interpretation ignores operating risk, however. That is, the cause and the effect may be reversed. A company may have more equity precisely because it is a riskier venture and bondholders want to make sure that the owners have a substantial risk exposure. This issue involves the nature of a firm's optimal capital structure, which is an unresolved area. The point to be emphasized here is that the leverage coefficient in the CCSA formula does not reflect the business risk of the operating company, only its leverage compared to that of the entire company. As such, the formula necessarily needs to be supplemented with information about the relative riskiness of companies in a similar business.

The equity cost estimation formula associated with the capital cost assignment (CCA) method is the same as that of the CCSA method, plus a complicated expression (shown in braces in table 6-7) involving the debt costs of the various companies. As such, it suffers from the same drawbacks as those described previously.

In the opinion of the authors, a fair characterization of the recent literature on double leverage methods is that most commentators suggest not using such methods when the unobserved, underlying riskiness differs among the subordinate operating companies.[9] That is, most writers on this topic have constructed examples similar to that in table 6-6 and concluded that under circumstances of unequal riskiness double leverage methods are inaccurate. The analysis and perspective adopted in this chapter corroborate this conclusion. Despite this, some analysts nonetheless may be tempted to continue to use such double leverage estimation methods. After all, as we know from statistics, it is sometimes preferable to use an estimator that is known to be biased if it has some other redeeming feature. In the case of double leverage, it is at least based on the market experience of an entity that owns the operating company, whereas the market experience of some unrelated, but similar company may be totally misleading, the argument might go.

What is needed is a way of driving home the point of just what it means for the double leverage formulas to neglect relative riskiness. This is missing, or at least has not been central, in the literature to date. The example in table 6-8 is intended to make clear the nature of

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[9]This recent literature includes Beedles, "A Proposal for the Treatment of Double Leverage"; Robert S. Stick, "The Four Fables of Double Leverage," Public Utilities Fortnightly, August 8, 1985, pp. 36-40; and Robert J. Sweeney, "Limitations on the Use of the Modified Double Leverage Approach," Public Utilities Fortnightly, April 4, 1985, pp. 41-44.

the fundamental deficiency of all double leverage estimation techniques. The example in table 6-8 is precisely the same as that in table 6-6 except that the relative operating risk of the two subsidiaries has been reversed and extremely so. The average of the two operating companies continues to require a 14 percent overall return to the consolidated company, as before. Because the WACC of the consolidated company does not change, the WACC of the parent also remains the same. Hence, all observable market information about the parent is the same as before, and because of this, all four double-leverage methods yield the same estimates as those in table 6-6. (The reader is invited to replicate the necessary arithmetic.)

Stating this even more strongly, any combination of operating risks of the various subsidiaries that has the same overall WACC for the consolidated company will result in the same capital cost estimates by any one of the four double leverage methods. That is, as the relative riskiness of the subsidiaries changes as just described, the estimate produced by each method does not change. There is some difference in the estimates among the four methods, of course, which has been the topic of this section. To illustrate this invariance to relative riskiness, as long as the consolidated company's WACC is 20 percent, it doesn't matter whether two equal size subsidiaries have unobserved WACCs of 10 and 30 percent, or 15 and 25 percent, or 20 and 20 percent, or 30 and 10 percent. In all of these cases, some of which are extreme opposites of one another, each method's estimate of each subsidiary's cost of capital does not change. Whatever minor differences there might be between the four techniques (Professor Beedles argues that his CCSA method is preferable because it is "in concert with the prescriptions of financial economics,"[10] for example) are totally and completely overshadowed by an absolute lack of ability to even so much as identify which of two companies is the more risky. All double leverage methods provide no

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[10]See Beedles, "A Proposal for the Treatment of Double Leverage," p. 36.

TABLE 6-8

UNEQUAL RISKINESS: FOUR DOUBLE-LEVERAGE METHODS

	Cost of Capital (%)	Capital Structure			
		Consolidated Company	Subsidiary 1	Subsidiary 2	Parent
Debt-Parent	12	$50			$50
-Subsidiary 1	10	50	$50		
-Subsidiary 2	9	25		$25	
Equity-Parent	19.67	75			75
-Subsidiary 1	26		50		
-Subsidiary 2	10.33			75	
		$200	$100	$100	$125
Weighted Ave. Cost of Capital (%)		14	18	10	16.6
Estimated Cost of Capital (%):					
Equity cost assignment (ECA)			13.3	14.7	
Capital cost assignment (CCA)			14	14	
Consolidated structure assignment (CCSA)			13.875	14.125	
Proportional structure assignment (PCSA)			13.3	14.7	
Estimated Equity Cost (%):					
Equity cost assignment (ECA)			16.6	16.6	
Capital cost assignment (CCA)			18	15.67	
Consolidated structure assignment (CCSA)			17.75	15.83	
Proportional structure assignment (PCSA)			16.6	16.6	

Source: Authors' calculations.

guidance whatsoever as to which company requires more and which company requires less of a return to capital than the observed, average required return of the consolidated company. Since the issue of double leverage seldom if ever arises except in a context where two or more operating companies have been combined, the analyst must always confront this utter lack of guidance. Without some other market information, possibly about comparable companies or possibly suggesting that all subsidiaries have the same risk (being careful to specify whether this is operating risk or equity risk), this is a fatal flaw, in our opinion. Any technique that purports to be able to estimate capital costs at the very least should be able to distinguish very high from very low risk companies. When such companies are combined under a single parent company, no double leverage technique can distinguish them, in fact.

In conjunction with estimates derived from independent market information, double leverage may be useful in establishing certain benchmarks as discussed in the first setion of this chapter. In the absence of such independent estimates, all double leverage methods basically attribute the consolidated company's WACC to all subsidiaries, with some correction for differing degrees of leverage. Financial analysts at PUCs need independent risk assessments to adjust up or down from this average. The leverage corrections provide no guidance and are as likely to be misleading as they are to be helpful.

Double leverage methods have long been criticized. Much of the criticism is misplaced, in our view. For example, on careful reading much of the criticism takes the form that if a particular type of cost assignment is made from parent to subsidiary (which often violates the fundamental market equilibrium conditions), ratepayers will benefit. This type of equity argument is not helpful in understanding whether or not double leverage methods provide good estimates of capital costs. This section has focused on the properties of double-leverage estimators and whether these provide any guidance in unraveling the underlying, unobserved, relative riskiness of the various subsidiaries. The answer is simply no.

A Brief Critique of the Literature

Much of the recent literature has correctly identified the major deficiency of double leverage concepts as an inability to estimate differing relative degrees of riskiness among the subsidiaries of a holding company. The subject still seems to be controversial, however, and for this reason a brief review of some well-known literature may be worthwhile. The purpose is to place some frequently encountered arguments into the estimation perspective developed in this chapter.

The early literature on double leverage focused on a holding company with a single subsidiary, although this was not made clear typically. Some of the arguments against double leverage presented in this early literature persist today, despite the fact that all double leverage concepts can accurately estimate a subsidiary's capital cost when only one company is owned by the holding company.

Perhaps the most popular case against double leverage was the *reductio ad absurdum* argument framed by Professor Brown.[11] Professor Brown states that double leverage "must be carried to its ultimate conclusion or lose its validity by stopping the argument in midstream."[12] Using a 13 percent return to equity, Professor Brown presents an example that begins with double leverage reducing an operating company's WACC from 9.5 to 7.1 percent. He then asks whether or not triple leverage should be considered to account for the fact that some stockholders may have used borrowed funds to purchase the company's common stock. He gives an example where triple leverage reduces the company's WACC even further, down from the already depressed level of 7.1 to 5.1 percent. Brown concludes that all investors, whether they be holding companies or individuals, are entitled to the same treatment at the hands of the PUC. Since the PUC would never investigate the leverage of an individual

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[11]See Brown, "Double Leverage: Indisputable FACT or Precarious THEORY," pp. 26-30.

[12]Ibid., p. 28.

investor, fairness requires that a holding company's leverage be similarly ignored, in Brown's view.

Before showing the fallacious nature of Brown's argument, it is constructive to recall that Brown was answered three years later by Basil Copeland, Jr.[13] Copeland's argument, although not incorrect, does not reveal the real problem with Brown's logic. Copeland focuses on the equilibrating process that ensures that the marginal investor will earn no more on his weighted average cost of funds, including any borrowed funds, than the market yield on the holding company's stock. The discipline of the market in preventing the individual investor from earning more than his own weighted average cost of capital convinced Copeland that there is no need to worry about triple leverage.

Copeland's reply is as unsatisfying as Brown's original argument. The difficulty, in part, comes from the focus on equity. Copeland's correct insight about the financial equilibrium of the marginal investor, is used only to conclude that the market prevents individuals from earning more than the normal return. This does not answer the question of whether to account for the triple leverage, however. To answer the question fully requires that we look at this triple-leveraged equilibrium. That is, Copeland stopped short of addressing the central issue.

Suppose the example introduced in table 6-1 is expanded to the case of triple leverage. That is, a wealthy investor purchases the holding company that has a single, regulated operating company. At this point, the emphasis in the previous section placed upon estimation and observability becomes critical. The equity viewpoint is to prevent any investor from earning more than the market return. This is a laudable goal, but it is not helpful in understanding leverage in these circumstances. The estimation perspective, on the other hand, reminds us to carefully state which financial instruments have observable market yields. If the private investor purchases the holding company's stock and then

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[13]See Basil L. Copeland, Jr., "Double Leverage One More Time," Public Utilities Fortnightly, August 18, 1977, pp. 19-24.

either holds it for a short time or resells it, it is still the holding company's equity which is being traded in the market place.[14] We observe the market yield of the doubly-levered holding company and make a correct estimate of the operating company's required WACC as shown in table 6-1.

If the private investor purchases the holding company and then forms a new company with publicly traded equity, the situation changes completely. In this case, the common stock of the holding company disappears from the market. Its yield is no longer observable, which creates precisely the same problem that occurs when the operating company's stock disappears into the treasury of a holding company. At this point, the double leverage methods are no longer viable because there is no information about the market yield of the holding company.

Is there a triple leverage technique that can be used in these circumstances to estimate the operating Company's WACC? The answer is trivially yes and is illustrated in table 6-9. The market yield on the equity of the parent of the holding company would be 26 percent, in order to be consistent with the fundamental financial equilibrium. This can be used to deduce the WACC of the parent of the holding company as 18 percent. This, in turn, becomes the estimate of the holding company's unobserved equity cost. The holding company's calculated WACC is 14 percent which next is used as the estimate of the operating company's unobserved equity cost. With this information, the operating company's WACC can be computed to be 12 percent, as before. The final estimate is accurate because the example obeys the market equilibrium condition and because there is only a single subsidiary.

The focus on estimation naturally leads to identifying which information is available in markets and which is not. Triple leverage does not pose an estimation issue until an investor, such as a holding

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[14]If the private investor buys all the stock of the holding company and holds it forever, then the shares would never be traded publicly. The financial analyst's problem then becomes the same as that encountered with privately placed stocks or family owned businesses. Information on the performance of the financial instrument is not publicly available. This is not a triple-leverage problem, however.

TABLE 6-9

A SINGLE SUBSIDIARY WITH TRIPLE LEVERAGE

	Cost of Capital (%)	Capital Structure: Consolidated Company	Operating Company	Holding Company	Parent of Holding Company
Debt-Parent of Holding Company	10	$12.5			$12.5
-Holding Company	10	25		$25	
-Operating Company	10	50	$50		
Equity-Parent of Holding Company	26	12.5			12.5
-Holding Company	18			25	
-Operating Company	14		50		
		$100	$100	$50	$25
Weighted Ave. Cost of Capital (%)		12	12	14	18

Source: Authors' calculations.

company, issues its own common stock and retires all shares of its subsidiaries. Hence, the leverage position of private investors is not an issue as long as the holding company's stock is actively traded.

In addition to the estimation viewpoint, it is important that the arguments made about double leverage also be consistent with the fundamental financial equilibrium described earlier. The examples used by Brown do not obey this condition. This is also true of the argument presented by Fitzpatrick who combines a debt cost of 6 percent and an equity cost of 15 percent in equal parts to determine a WACC of 10.5 percent.[15] If this were then doubly levered (50-50 at the holding company

[15]Dennis B. Fitzpatrick, "Subsidiaries' Capital Costs--A Compromise Approach," Public Utilities Fortnightly, June 23, 1977, pp. 23-30.

level), he finds the operating company would have a WACC of only 8.25 percent. He finds this because he assumes that the cost of equity is somehow constant. It is not. When the holding company settles on a 50 -50 capital structure, investors will require a higher return to its equity reflecting its greater financial risk. The operating risk remains the same, however. The holding company's return on equity must be 24 percent in the market place. The holding company's WACC then would be 15 percent (consisting of equal parts of 6 percent debt and 24 percent equity), which would be used as the estimate of the operating company's equity cost. Combining this with the subsidiary's 50 percent of 6 percent debt results in the same 10.5 percent WACC, as before.

The mistake was to assume that the equity cost remains the same, regardless of leverage. Greater and greater leverage seemingly has the effect of reducing the overall required return if equity cost were to remain the same. In reality, greater leverage has the effect of increasing the return to equity to whatever level is needed so that the overall opportunity cost of investors' funds equals the return from the underlying real assets.

That equity cost is constant regardless of leverage is a common fallacy and it takes several forms. Professor Brown, for example, states that leverage saves consumers several million dollars per year and that "the demonstrated benefits of leverage have historically been passed on to consumers in the form of lower utility rates."[16] This is the common viewpoint that financing with less costly bonds reduces a company's WACC. Bonds are actually cheaper, however, because bondholders have a superior claim to a company's assets relative to equity owners. Equity owners require a higher return as more and more bondholders are allowed to line up in front of them.

Conclusion

In reality, the issue of whether equity cost remains constant or whether the overall WACC remains constant as more debt is issued is not

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[16]Brown, "Double Leverage: Indisputable FACT or Precarious THEORY," p. 27.

completely straightforward. The viewpoint taken in this chapter has been that the truth is much closer to the latter rather than the former. The tax deductible status of interest payments complicates the argument. But the same conclusion can be reached by expressing matters in terms of the overall after-tax return required by investors. Also, the issue of the optimal capital structure is important. There may be limits on how much leverage will be tolerated before bondholders require a higher yield.

These complications, however, are not inconsistent with the viewpoint taken in this chapter, which is that the fundamental financial equilibrium condition must be satisfied. This requires an equality between the WACC of investors' funds and the required return on an asset. The asset's required return is determined by its business or operating risk, which is not affected by the company's financial leverage. This condition must be satisfied even if an operating company is owned by a holding company. If the holding company has but one subsidiary, the parent company's observed market yield on equity can be used to accurately estimate the subsidiary's WACC. In these circumstances, the fundamental financial equality will prevent any systematic estimation errors such as those feared by early critics like Brown and Fitzpatrick.

If a holding company owns more than one subsidiary, however, the double leverage method provides no guidance on how to sort out and estimate the relative operating risk of the component companies. All four double leverage techniques necessarily estimate the WACCs of all of the subsidiaries as some sort of average based upon unlevering the parent company's WACC. This average is further corrected for the relative leverage of the individual subsidiaries in two of the four methods discussed in this chapter. These corrections for leverage, however, completely neglect, as they must, any differences in operating risk among the subsidiaries. Because all double leverage methods are based solely on the observed market yield of the parent company (which is an aggregate of the component companies' equity costs), none of these methods contains any information about the relative operating riskiness of the subsidiaries. An infinite number of combinations of such riskiness could have resulted in the same observed market yield of the parent. There is no way of identifying which combination most likely has caused the observed return, or even which combination is more likely than any other. All are equally plausible candidates until some independent information is brought to bear.

Such information might be market yields for companies that are comparable to some subset of the subsidiaries. Or it might be an observation that the subsidiaries have about the same operating risk or about the same equity cost. Whatever the source, all double leverage methods require an independent source of information to establish the relative riskiness of the individual subsidiaries.

CHAPTER 7

EVALUATING TRANSFER PRICES

This chapter focuses on the economic issues surrounding the proper valuation for ratemaking purposes of cost transfers between an electric utility and its affiliates that occur during affiliate transactions.

The chapter is focused primarily on the proper valuation of transfer prices in affiliate transactions, and contains a brief discussion of the various approaches and methods for evaluating transfer prices in affiliate transactions, examining the pros and cons of each. The chapter has five sections. The first contains an analysis of the market-price approach, while the second discusses the potential difficulties of applying the market-price approach. The third and fourth contain analyses of two rate-of-return approaches: the profit-comparison and the utility-rate-of-return approaches, respectively. The fifth discusses how to apply these rate-of-return approaches. Before discussing the various approaches and methods for valuating transfer prices, the authors next briefly discuss the transfer price issue.

A transfer price is the price charged by one segment of an organization for a product or service that it supplies to another segment of the same organization. Because transfer prices arise in transactions between related entities, they are not the result of an arms's-length bargaining process and thus may not reflect the true or fair market value of the goods or services being transferred. However, because the effects of inter-company transactions are eliminated in the course of consolidated financial reporting procedures required under G.A.A.P., the validity of transfer prices in transactions between affiliated entities is seldom of interest to parties outside the consolidated corporate structure; the transfer price is only of interest to the company's top-level management, who are concerned with such issues as goal congruence and performance evaluation. The validity of transfer prices only becomes an issue when the performance of one of the corporate segments is being separately evaluated by a governmental agency or regulatory authority. For our purposes, this situation occurs where a regulated utility is affiliated with a nonregulated firm. In this situation the transfer prices between the affiliated entities must be subjected to careful scrutiny, since top-level management will have an incentive to use the transfer prices as a means of manipulating the income or expenses of the segment being evaluated.

Thus whenever a regulated utility engages in formal transactions with a subsidiary or affiliated entity, commissions monitor these transfer prices to ensure that they are not a device for siphoning funds from the regulated utility to the nonregulated subsidiary. Although a few states require prior commission approval of all contracts with subsidiaries, in most states the monitoring process usually takes place after-the-fact in the context of the ratemaking procedure. At this time the regulators review the utility's costs of service--including those costs incurred in transactions with subsidiaries--to determine whether they should be included as a recoverable cost of service.

Although the resurgence of electric utility diversification is a relatively recent phenomenon, state commissions are not, of course, unaccustomed to dealing with various issues of transfer price valuation. In the telecommunications rate cases the transfer pricing issue has typically involved the purchases of equipment by AT&T affiliates from the Western Electric Company, also an AT&T subsidiary. With electric utilities, the transfer pricing issue most frequently involves the purchase of coal by an electric utility from an affiliated coal mine. Because this is the most common context in which the transfer pricing issue arises, the authors generalize from affiliated coal purchase examples.

There are already well established methods for evaluating transfer prices from affiliated entities. Each of these methods establishes a benchmark price, against which transfer prices in affiliated transactions can be compared to determine whether or not the transfer price is unreasonable or excessive. These methods can be grouped into three theoretical approaches:

* market-price approach
* profit-comparison approach
* utility-rate-of-return approach

Under the market-price approach, the affiliate's transfer prices are deemed reasonable if they are less than or equal to those charged by nonaffiliated suppliers of the same goods or services. Under the profit-comparison approach, the subsidiary's prices are considered reasonable if the return on capital i.e., "profit" earned by the subsidiary does not exceed that earned by nonaffiliated suppliers of the same goods or services. Finally, under the utility-rate-of-return approach,[1] the prices are considered unreasonable, and thus not recoverable from customers, to the extent that the subsidiary earns more than the sum of its costs and a return on capital based on the rate of return that the regulated public utility is allowed to earn.

These methodologies for allocating costs between electric utilities and their subsidiaries must be examined in light of the fundamental objectives of regulatory policy. These objectives are fourfold: (1) to prevent the utility from earning supra-competitive profits, (2) to allow diversification only to the extent that it produces economic benefits, (3) to encourage efficiency in the operations of both the utility and its subsidiary, and (4) to encourage the efficient utilization (i.e., conservation) of scarce energy resources.

Analysis of the Market-Price Approach

The market-price approach is one of the approaches used by the FERC and various state commissions in determining the reasonableness of expenditures made by utilities to their subsidiaries.[2] This approach involves a comparison of the price actually paid by the utility to an affiliated supplier with the price the utility could have paid to a nonaffiliated supplier under similar terms and conditions. Costs in

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[1]The utility-rate-of-return approach is also sometimes called the "California approach". The term "California approach" appears to have been coined in a 1976 law review article: "Note, Treatment of Affiliated Transactions in Utility Ratemaking: Western Electric Company and the Bell System," 56 B.U. L. Rev. 558 (1976). The term "California approach" has been subsequently used by many commentators, though several states now use this approach.

[2]See Public Service Co. of New Mexico (Phase II) (PNM II), 13 FERC ¶63,041 (1980), aff'd, 17 FERC ¶61,123 (1981).

excess of the market price benchmark are not recoverable for ratemaking purposes.

The market-price approach is premised on the concept that the utility's subsidiary is an "independent entity"--separate and apart from the utility. The market-price approach is consistent with the approach for allocating financial capital costs which calls for the elimination of all investments in nonutility businesses from the equity component of the consolidated company's capital structure. The market-price approach thus treats the subsidiary as an independent entity and does not attempt to regulate its profits or rate-of-return.

One of the practical drawbacks of the market-price standard is that it presumes the existence of a competitive market for the good being transferred. The test will not be effective if the affiliate exercises sufficient oligopolistic or monopolistic power to be able to influence prices for the good being sold. If this were the case, the market-price test would be little more than a meaningless comparison between a price set directly by the subsidiary (the transfer price) and an array of market prices indirectly influenced by the subsidiary due to its dominance in the market. Thus the market-price approach was deemed to be of little use in an earlier telephone rate case, because Western Electric, at that time, exercised a dominant position in the relevant market.[3] In the context of captive coal mining, since coal markets are regional--rather than national --in scope, there may be situations where an affiliated coal producer could exercise considerable influence over the prevailing price in a regional coal market--thus rendering the market price test an unsatisfactory standard. In such instances, the commission would have to apply an alternate transfer pricing method--such as the profit-comparison test or the utility-

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[3]See Pacific Tel. & Tel. Co. v. P.U.C., 401 P. 2d 353, (Calif. 1965), where the court stated: "The advantage that the Bell System has...[as] operator of 80 percent of the telephone business in the entire continental United States makes it impossible to compare one phase of its operations, that of Western Electric, with outside companies who have none of the same spread of operations and control either in utility businesses or with respect to any business within which the outside companies operate."

rate-of-return approach--in order to regulate affiliate transactions between the utility and its subsidiary.

Another key assumption underlying the use of this approach is that the utility's investment in the subsidiary is financed <u>entirely</u> out of the utility's retained earnings and not from any contributions from the ratepayers. If this implicit assumption is violated--i.e., if the subsidiary is financed partly by ratepayer contributions--the use of the market price approach may not be preferred. Then it may be argued on fairness grounds that the ratepayers should be allowed to benefit from any cost savings resulting from this investment.

A corollary of the assumption that the utility's original investment in the subsidiary was not underwritten by ratepayer contributions is the implicit assumption that there is no cross-subsidization of the subsidiary by the utility in its day-to-day operations. If ratepayer contributions were being routed to the subsidiary, then--once again--the argument could be made on fairness grounds that the ratepayers should be allowed to share in the benefits of these reduced costs. In this case the profit-comparison test may be more appropriate than the market price test since under the profit-comparison test the profits resulting from the cross-subsidization would be passed on to the ratepayers in the form of lower rates (assuming the subsidiary was otherwise competitive with other firms in its industry).

The market-price approach is conceptually appealing from an economic point of view, since the market price reflects the relative scarcity or opportunity cost of the good in question. The competitive market-price standard therefore encourages the "best" use (from a societal point of view) of our scarce resources. In the context of affiliate transactions between electric utilities and their coal mining affiliates, this means that a market-price standard for coal prices would, for example, encourage ratepayers to conserve energy whereas a price below the market price--which would be passed on to consumers in the form of lower rates--would encourage the inefficient and wasteful use of energy.

The market-price approach also encourages efficiency of production by captive subsidiaries. A captive subsidiary is one which sells all or a substantial portion of its output to the parent utility. By allowing captive subsidiaries to retain their profits (i.e., the difference between their production costs and the prevailing market price), the market-price standard creates the proper incentive for the subsidiaries to minimize production costs. In contrast, a rate-of-return approach would only encourage efficient production by a captive subsidiary to a limited extent. Producers would have an incentive to keep the sum of their costs plus the allowed rate of return equal to the market price; captive subsidiaries would have no further incentive to achieve greater cost savings, since these would all be passed on to the utility's ratepayers.

Finally, the market-price approach encourages the efficient allocation of the utility's financial resources. This is due to the fact that under the market-price standard (as opposed to the other two allocation methods) the subsidiary is allowed to retain all of its profits regardless of the subsidiary's rate of return. Thus the subsidiary (and ultimately the utility's shareholders) will benefit from any competitive advantage that it might have over its competitors. Those advantages could be associated with a variety of factors, including greater efficiency, superior mineral resources, or synergistic benefits from the parent-subsidiary relationship. To the extent that the utility's investment in a "related" business activity does, in fact, result in some form of synergistic benefit, the market price approach encourages utilities to invest in "related" as opposed to wholly "unrelated" businesses, thereby encouraging the most beneficial use (from a societal point of view) of society's scarce resources.

Application of the Market-Price Approach

One of the practical advantages of the market-price test is that this standard does not require an in-depth cost-of-service study. Thus, at first glance, the market-price test may appear easier to apply in practice than either of the rate of return methods. However, the market-price standard may be more difficult to apply effectively than either the profit-comparison test or the utility-rate-of-return approach.

There are two necessary conditions for the effective application of the market-price standard--one theoretical and the other practical. The theoretical condition is that the market-price standard will not be effective if the affiliate controls a large enough share of the relevant market to dictate prices.[4] The practical condition is that the commission must be capable of identifying the applicable market, and of computing the applicable comparative market prices to be used in applying the standard. Thus, in the case of coal, effective application of the market price standard requires: (1) identification of the relevant regional coal market(s); (2) calculation of comparable market prices from the utility's perspective; and (3) assurance that the affiliated coal producer is not in a position to be able to influence market price.

The coal resources of the United States are distributed among five major coal basins. These coal basins are illustrated in Figure 7-1. Due to the regional insulation created by high transportation costs, the basins traditionally have been associated with coherent regional coal markets. However, there is no consensus as to the size or number of these regional coal markets; the precise definition of these markets would vary according to the method being used for market delineation.[5]

Of the various methods for defining regional coal markets, some focus primarily on supply-side autonomy; these methods analyze the percentage of imports into a region to determine whether the region is self-sufficient

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[4]See footnote 3 and accompanying text.

[5]See generally Kenneth G. Elizinga and Thomas F. Hogarty, "The Problem of Geographic Market Delineation Revisited: The Case of Coal," 23 Antitrust Bulletin 1 (1978), and articles cited therein. See also Department of Justice, Competition in the Coal Industry (Washington, D.C.: U.S. Government Printing Office, 1978); General Accounting Office, The State of Competition in the Coal Industry (Washington, D.C.: U.S. Government Printing Office, 1977); Tennessee Valley Authority, The Structure of the Energy Markets: A Report of TVA's Antitrust Investigation of the Coal and Uranium Industries (Washington, D.C.: U.S. Government Printing Office, 1977).

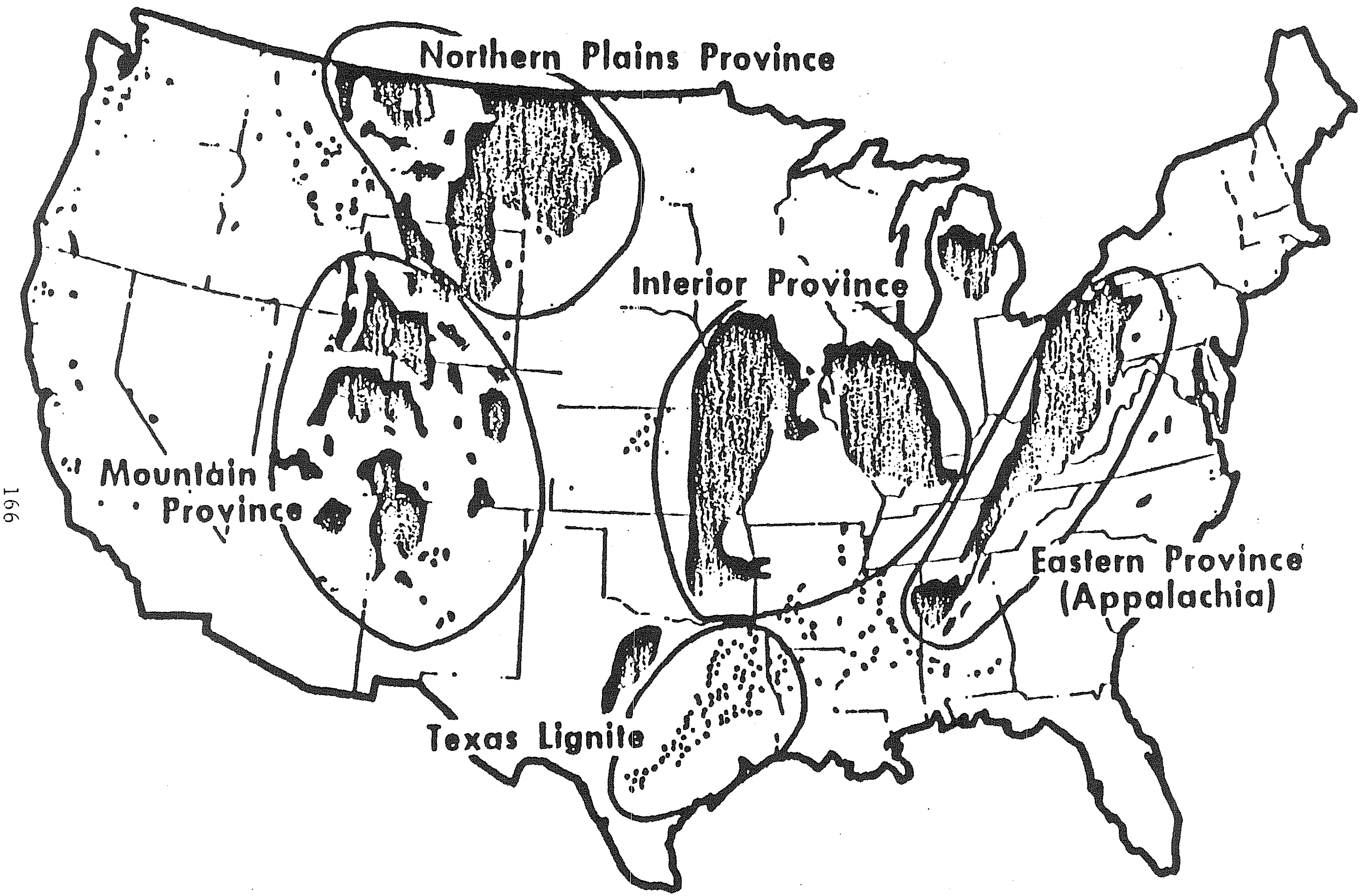

Figure 7-1. Five major coal basins of the United States

Source: Department of Energy, Coal Competition: Prospects for the 1980's, p. 334

with respect to supplying its own coal needs.[6] Other methods stress both supply-side and demand-side autonomy; these methods analyze both imports into and exports from various regions to determine whether the region is self-contained.[7] There is no single correct methodology for delineating coal markets. For purposes of applying a market price test--a methodology which encompasses both supply and demand influences may be more useful--since it will yield a smaller number of large, well-defined, discreet markets, than will a strictly supply-sided methodology.[8] On the other hand, for purposes of determining the ability of a coal mining affiliate to influence prices in a given market, a supply-side methodology may be preferable, since it will better capture the ability of a regional monopolist to charge more than competitive prices to the consumers in the region.[9]

By way of illustration, Figure 7-2 shows four discreet coal regions defined using the LOFI-LIFO methodology of Elzinga and Hogarty. Table 7-1 shows captive coal deliveries as a percentage of the total for each of these four regional markets.

Once the commission staff has defined the appropriate regional coal market, it must then determine whether a given coal-producing affiliate exercises sufficient monopoly power in that regional market to be able to influence prices. For such purposes, the commission staff would want to consider the subsidiary's regional market share, in light of the characteristics of that particular market.

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[6]See e.g., P. Giffen and J. Kushner, "Geographic Submarkets v. Bituminous Coal: Defining a Southeastern Market," 21 Antitrust Bulletin 67 (1976); Ronald E. Shrieves, "Geographic Market Areas and Market Structure in the Bituminous Coal Industry," Appalachian Resource Project, University of Tennessee, Number 45 (no date).

[7]See e.q., Kenneth G. Elizinga and Thomas F. Hogarty, "The Problem of Geographic Market Delineation in Antimerger Suits," 18 Antitrust Bulletin 45 (1973).

[8]Department of Energy, Coal Competition: Prospects for the 1980's, Appendix G: Delineation of Regional Coal Markets, pp. G-1 - G-2.

[9]Ibid.

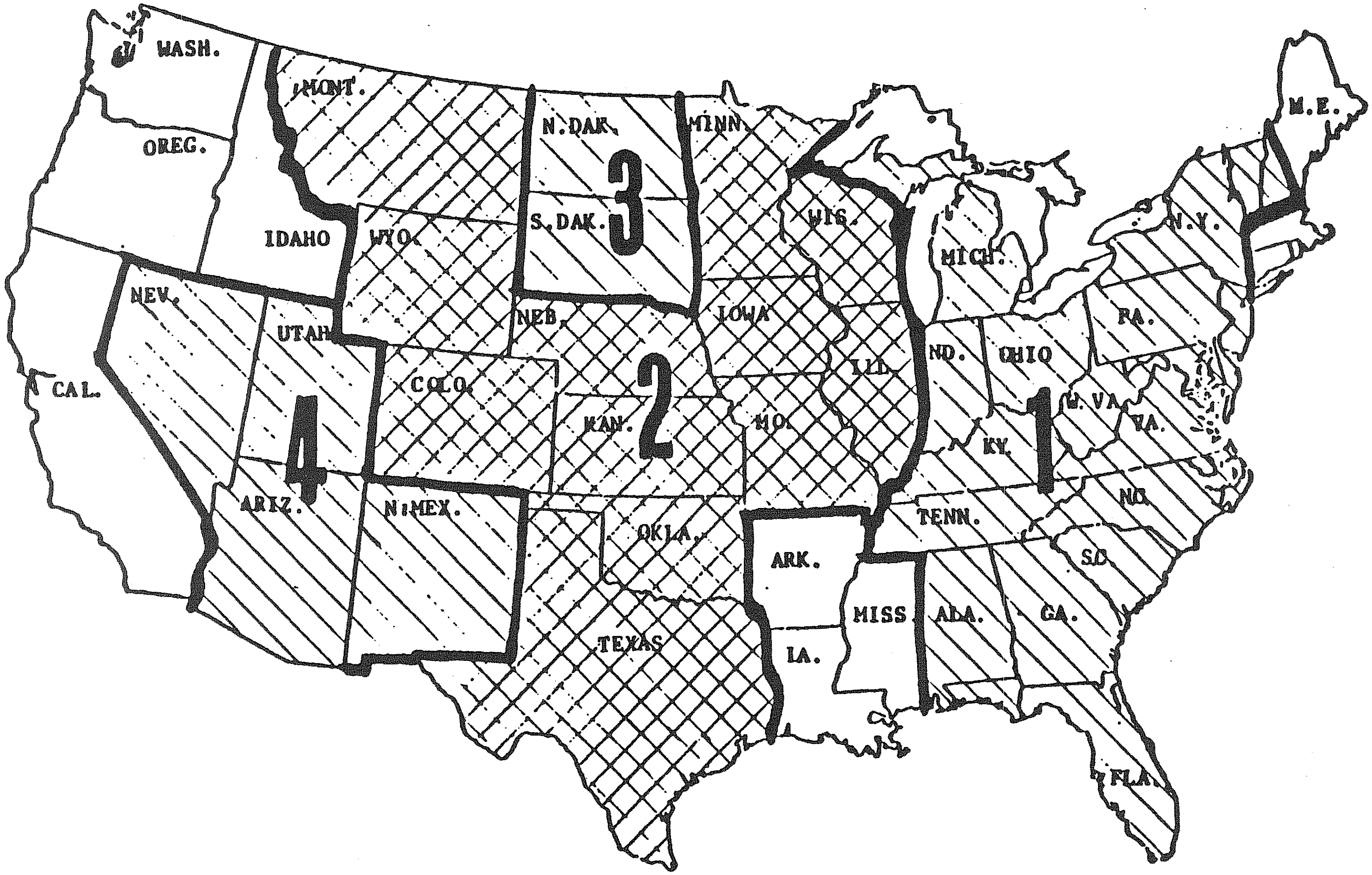

Figure 7-2. Four discreet regional coal markets

Source: Department of Energy, Coal Competition: Prospects for the 1980's, p. 346.

TABLE 7-1

CAPTIVE COAL AS A PERCENTAGE OF TOTAL COAL DELIVERED TO THE REGIONAL COAL MARKETS IN 1978 AND PROJECTED TO 1985*

Regional Coal Markets	Total 1978 Coal Deliveries in 10^3 Tons	1978 Captive Deliveries in 10^3 Tons	Captive % of Total	Projected 1985 Total Coal Deliveries in 10^3 Tons	Projected 1985 Captive 10^3Tons	Captive % of Total
No. 1 (Eastern)	288,154	29,620	10.3	355,584	47,700	13.4
No. 2 (Central)	145,977	29,189	20.0	273,427	67,400	24.7
No. 3 (Dakotas)	11,565	1,055	9.1	24,465	1,900	7.8
No. 4 (Southwest)	22,498	5,131	22.8	42,748	16,300	38.1
TOTAL	468,194	64,995	13.9	696,224	133,300	19.1

Source: U.S. Dept. of Energy, Coal Competition: Prospects for the 1980s, p. 327.

* These data do not include coal deliveries to the states which were not part of the 4 regional coal markets delineated in Map #1. In 1978 these states used relatively small quantities of coal; in total they received only 8 million tons of coal that year. The projected 1985 total electric utility coal consumption quantity of 696,224 thousand tons does not include the coal which will be consumed in the states outside of the four coal market areas.

Since different regional markets have varying degrees of concentration, regulators would need to take this fact into consideration when determining whether the market-price test should be applied in a given instance. Regulators would also need to bear in mind the dynamic nature of coal markets: not only are the degrees of concentration changing within the individual regional markets,[10] but the markets themselves are undergoing constant change. Thus, there is a need for periodic reassessment of the market structure and of the subsidiary's ability to influence price within that market.

Once the commission staff has determined that the market-price standard can appropriately be applied, it must then determine the comparable market prices. The major difficulty is that coal is not a fungible good. Rather, coal deposits have unique properties and characteristics with respect to ash, moisture, sulphur, and Btu content, as well as grindability, fusion temperature and volatility.[11] Thus, in any given regional market, coal prices may vary by as much as 25 cents/10^6 Btu, depending on sulfur content and other characteristics.[12] However, in order to apply the market-price approach effectively, the commission must be able to isolate and quantify the effects of each of these individual characteristics on the product's price. This is necessary in order to

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[10]The D.O.E. study indicates that at the present time, utility-owned captive coal operations do not have a significant anti-competitive impact on regional coal markets. However, future projections for rapid growth in captive coal use, together with the increasing numbers of electric utilities acquiring coal reserves, suggest that captive coal operations may reduce the level of competition in the coal industry in the future. Department of Energy, Coal Competition: Prospects for the 1980's, pp. 293-94.

[11]Department of Energy, Coal Competition: Prospects for the 1980's, p. 354. See also, Marie R. Corio and Alice E. Condren, "Which Coal at What Cost?" Public Utilities Fortnightly March 15, 1984: pp. 32-36.

[12]Department of Energy, Coal Competition: Prospects for the 1980's, p. 321.

use a given market price as a basis of comparison with a transfer price for coal with different characteristics. Unfortunately, many state commissions would probably lack the resources and the expertise to undertake such a monumental task, assuming such factors were capable of estimation. Thus a Department of Energy study concluded: "With so many factors affecting coal prices it would be difficult to isolate and quantify the effects of varying concentrations of sulfur on coal prices....the only conclusion that can be drawn is that lower sulfur coal does command a higher price than higher sulfur coal, all other things being equal."[13]

Yet another factor which commission staffs must consider when making market price comparisons is the cost of transportation. A Department of Energy study points out that "the costs of transporting coal from a mine to a given power plant eliminates most national coal deposits and even deposits within a coal market region from consideration by a given utility. The ultimate transportation costs utilities pay range from nearly nothing to over half the delivered price of coal, depending upon relative proximities of mine and plant, and available transport modes".[14] Thus, commission staffs must make adjustments for differences in location and transportation costs--taking into consideration the available modes of transportation--when comparing coal prices.[15]

Finally, commissions must account for differences in contract terms--particularly contract size and duration. Captive coal prices should be compared to coal prices for long-term supply contracts (never to spot market prices) since a captive coal mining operation is, in essence, a substitute for a long-term supply contract. Moreover, regulators would also need to take into account differences in the contract start-up date between the captive-coal contract and the market contract, since newer contracts typically have higher prices due to the increasing costs of opening new mines.

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[13]Ibid.

[14]Ibid., p. 354.

[15]Ibid., p. 320.

As the preceding paragraphs suggest, accurately computing comparable market prices is a task of extreme difficulty, which suggests that use of alternative methods might be reasonable. Ideally, in applying the market price test, the regulator would have to consider the prices of all alternate suppliers in the market, making appropriate adjustments for differences in physical properties, transportation costs and contract terms. After all alternative market prices had been adjusted, the commission would determine whether the transfer price appeared to be reasonable.

Making the necessary adjustments for differences in physical properties, transportation costs and contract terms, may be very difficult and impractical to implement. A recent Department of Energy study suggests that this may be true. The study, which compared the economic and price efficiency of noncaptive mines with that of captive mines, subject to various forms of transfer pricing regulation, revealed that mines regulated under the market-price test were the least efficient--both in terms of price and technical efficiency.[16] This result, of course, was counter to the results expected based on economic theory. The authors of that study concluded, however, that a plausible explanation for this result was that regulators using the market price approach were sometimes unable to determine a representative market price--the result being that affiliated coal companies are permitted to charge higher prices than they could if the "correct" market price were known by the regulatory authorities.[17] Another plausible explanation is that the Department of Energy study was not long-term and might have suffered from a "snap shot" effect. One might expect that over a long period of time, captive coal mines would be more efficient in terms of price and tehnical efficiency than noncaptive mines. But in any particular year, the captive mines might be more or less efficient and have prices above or below the market, hence the "snap shot" effect.

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[16]Ibid., p. 316.

[17]Ibid.

Analysis of the Profit-Comparison Approach

The profit-comparison approach was first used in the context of telecommunications cases, involving transactions between AT&T affiliates and Western Electric. The market-price approach was deemed to be of limited applicability in these cases because, at that time, Western Electric dominated the market for most of the equipment it supplied.[18] Regulators thus resorted to the analysis of the affiliate's rate of return in an effort to determine what the market price would be. Thus the profit-comparison approach first evolved as a proxy for the market-price approach, and was not originally regarded as a separate or distinct transfer pricing method. Only recently, in the context of energy-related transfer pricing issues, have courts and regulators distinguished between the market-price approach and the profit-comparison approach.[19]

Under the profit-comparison test, as currently applied, the subsidiary's rate of return is compared with the rate of return for similar firms in the same industry. If the subsidiary's rate of return exceeds that of similar firms, the transfer price is deemed to be excessive even though it may be less than or equal to the competitive market price.

The profit-comparison test is based on the assumption that if the subsidiary's profits are higher than those of other firms in its industry, then these profits are the result of either synergistic benefits from the parent-utility relationship, or some kind of implicit subsidization of the subsidiary by the utility. For example, some would argue that a captive subsidiary benefits from the utility-subsidiary relationship more so than the utility because the captive subsidiary has an assured market for its product. This assured market, which is a result of the utility-subsidiary relationship, in effect shifts a portion of the subsidiary's riskiness onto the utility. This shifting in the risk has value, and represents an implicit subsidization of the subsidiary by the utility. To the extent that synergistic benefits are derived from the application of the utility's

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[18]See footnote 24 and accompanying text.

[19]See e.g., Central Louisiana Electric Co., Inc. v. Louisiana Public Service Comm., 373 S. 2d. 123,129 (La. 1979).

management expertise to a related field or business endeavor, a form of cross-subsidy results, since some of the time and efforts of the utility's management are devoted to the subsidiary that otherwise would have been devoted exclusively to the utility. Such cross-subsidies, however, are virtually impossible to measure with any degree of precision in the accounting or auditing process. Also, where the utility finances its subsidiary with retained earnings that would otherwise have been used for capital expenditures and then borrows capital for its capital expenditures, the utility's debt-to-equity ratio increases. As a result, the cost of capital for the utility increases--since future utility financing will have to be composed of a higher percentage of more costly equity than would otherwise be the case. Proponents of the profit-comparison test argue that the ratepayers should be allowed to benefit from this synergism in the form of reduced rates--particularly where the subsidiary's profitability may be due to some form of implicit cross-subsidy from the utility, or where the parent's investment in the subsidiary is highly leveraged.

Another plausible cause for the subsidiary's excessive rate of return is a possible competitive advantage which is wholly unrelated to the subsidiary's relationship with the utility. Such an advantage could be related to superior resources (ownership of a particularly rich mine), superior management, or any of a variety of factors. While it can be argued on fairness grounds that ratepayers should be allowed to share in the benefits of synergism, an argument can be made that the subsidiary's owners (i.e, the utility's shareholders)--not the ratepayers--should benefit from the profitability of the utility's investment in the subsidiary--particularly when the investment is financed solely out of the utility's retained earnings. However, probably due to the fact that the amounts of such rents--if any--cannot be measured,[20] proponents of the profit-comparison test prefer to discount their significance as a component of the subsidiary's profits. On the other hand, when the investment in the subsidiary does not come solely out of retained earnings and the ratepayers

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[20]The existence of rents as a component of excess profits could perhaps be indicated by comparing the subsidiary's pre-acquisition rate of return with that of other firms in the industry.

have contributed to the investment, it would be appropriate for ratepayers to share in the profitability of the subsidiary.

One drawback associated with the profit-comparison standard is that it does not lend itself to a consistent application in all transfer pricing situations. Although application of the profit-comparison test results in lower rates for ratepayers in cases where the subsidiary is more profitable than most of the firms in its industry, the application of this standard in cases where the subsidiary's rate of return is less than average would result in higher rates for the ratepayer than if the utility had purchased from a nonaffiliated supplier. Thus if the profit-comparison standard were applied on a consistent basis, both the ratepayers and stockholders would benefit from the subsidiary's profitability, but they would also bear the risk of the subsidiary being unprofitable. Rather than applying the profit-comparison test in all cases, therefore, regulators are inclined to switch to a market-price standard when a subsidiary is inefficient and charges more than the market price for its product, and switch to the profit-comparison test where the subsidiary is profitable and is able to beat the market price.[21] Such treatment allows the utility to recover from customers only the lower of market price or cost of production, and would therefore discourage utility diversification into related areas (i.e. fuel production) regardless of potential benefits. On the other hand, application of the profit-comparison test in all cases could encourage the continued operation of inefficient subsidiaries and would provide little incentive for efficiency on the part of either the utilities or their subsidiaries. Another aspect of the inconsistency associated with the profit-comparison test is that unlike the market-price test, the profit-comparison test is only applied in situations involving upstream sales (i.e., sales by the subsidiary to the utility). In downstream sales (i.e., sales from the utility to the subsidiary) involving the sale of assets or equipment, regulators are inclined to apply a fair market value standard

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[21] See discussion of survey results in chapter 3. Several states indicated that they apply some form of rate-of-return standard, using the market price as a ceiling.

(which is equivalent to the market-price test) since to do otherwise would effectively prevent the utility--and thus the ratepayers--from realizing the full value of the appreciation on assets as carried on the utility's books at historical (and sometimes original) cost.

Analysis of Utility-Rate-of-Return Approach

A variant of the profit-comparison test is the utility-rate-of-return method. Like the profit-comparison test, the utility-rate-of-return approach examines the subsidiary's rate of return (rather than comparable market prices) in determining the reasonableness of transfer prices. However, under the profit-comparison test the subsidiary's rate of return is compared with that of similar firms in the same industry, whereas under the utility-rate-of-return approach a transfer price is deemed to be excessive if it permits the subsidiary to earn a rate of return higher than that allowed to the parent utility.

Each method had its genesis in the context of telephone rate cases. They evolved from a line of decisions by the California Supreme Court, which having previously rejected the applicability of the market-price test in telephone cases,[22] adopted the California Public Utility Commission's position that transfer prices in affiliate transactions between a regulated utility and its affiliates were to be deemed reasonable, only if the transfer price allowed the affiliate to earn "no greater rate of return than would be reasonable for a regulated utility."[23] The court explained its position in City of Los Angeles v. P.U.C., stating that where a utility enjoys a dominant market position, "it may not through the use of corporate diversification obtain a greater rate of return than [it] would be entitled

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[22]Pacific Tel. & Tel. Co. v. P.U.C., 401 P.2d 353 (Cal. 1965).

[23]City of Los Angeles v. P.U.C., 497 P.2d 785,795 (Cal. 1972).

to in the absence of the separate corporate entities."[24] Thus the court's underlying rationale was that a utility "should not be permitted to break up the utility enterprise by the use of an affiliated corporation and thereby obtain an increased rate of return for its activities."[25] The utility-rate-of-return approach is therefore based on the premise that the utility's affiliate is, in fact if not in law, a part of the public utility and therefore should be regulated as a utility for purposes of determining reasonable rates of return on affiliate transactions with the utility.

In the context of the pre-divestiture telephone industry, the California approach had substantial justification. Since the terminal equipment market was at that time subject to regulation, and the Bell System companies had been the sole supplier of terminal equipment, it was logical to speak in terms of the Bell System attempting to evade regulation by "breaking up the utility enterprise" through the use of affiliated corporations. The same analysis, however, may not be so easily applied in the context of captive coal mining by electric utilities.

Unlike the telephone industry, in the electric industry, coal mining has not been a traditional function of most electric utilities; the increase in "captive" coal mining by electric utilities is a relatively recent phenomenon.[26] Electric utilities have traditionally bought their coal from independent, nonaffiliated suppliers, relying primarily on long-term contracts to obtain coal in the quantity and quality needed. However, in the last two decades, such circumstances as changing environ-

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[24]Ibid., p. 795.

[25]Ibid.

[26]A recent D.O.E. study shows an increase in captive coal deliveries from 13.4 million tons in 1965--or 5.5% of the total--to a projected 143.2 million tons in 1985--or 19.5% of the total coal deliveries to utilities. U.S. Department of Energy, Coal Competition: Prospects for the 1980's, p. 300.

mental regulations[27] for both coal producers and utilities, rapidly increasing costs of coal production, and rapidly increasing coal prices (not always cost-related) resulted in a situation where coal suppliers and utilities were reluctant to sign long-term coal supply contracts which might prove disadvantageous in the future. Many utilities may have turned to captive coal production as a means of hedging against price fluctuations while at the same time avoiding payment of the "risk premium" typically associated with long-term contracts to the coal supplier. Thus the recent increase in captive coal mining by electric utilities need not necessarily be interpreted as an attempt solely to evade regulation but rather as an attempt to obtain an assured supply of coal in the face of uncertain market conditions.[28] In the case of coal mining subsidiaries of electric utilities, therefore, the same justification for restricting the subsidiary's rate of return as in the telephone cases may not necessarily apply.

Another difficulty of the utility-rate-of-return approach from an economic perspective is that it may discourage utilities from investing in newly "related" or vertically-integrated activities, such as coal production, where utilities are most likely to realize some form of synergistic benefits from their investment. Since one of the objectives of regula-

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[27]Tighter regulatory restrictions may be a significant factor influencing electric utilities to invest in coal--particularly low ash, low sulphur coal. With more and more generating plants being designed or reconverted to burn low sulphur coal, there is an increasing concern on the part of utility management about the need to assure a steady supply of the utility's design coal--either through long-term supply contracts or through captive mining--since use of a different grade or quality of coal will result in more frequent breakdowns and overall performance losses. See e.g., Corio and Condren, "Which Coal at What Cost?" pp. 32-36. See also Francis Kovalcik, "New Flexibility in Fuel Planning," EPRI Journal, July/August 1985, pp. 22-37.

[28]In a 1977 survey of electric utilities with captive coal operations, security of supply was the most commonly cited justification for integration into coal production. Federal Power Commission, Bureau of Power, Electric Utilities' Captive Coal Operations, (Washington, D.C.: U.S. Government Printing Office, June 1977) cited in U.S. Department of Energy Coal Competition: Prospects for the 1980's, p. 301.

tory policy is to encourage the "best" use of society's scarce resources, it follows that state regulatory policy with respect to diversified subsidiaries might best be one which encourages (or at least does not penalize) utility investment in "related" or vertically integrated industries, where economies of scope or some form of synergistic benefit is likely to result from the integration.[29] However, since these synergistic benefits are a result of the functional interrelationship between the utility and its vertically integrated subsidiary, they can only be realized to the extent that there is mutual cooperation between the two entities--either through a sharing of common costs or sharing managerial expertise or establishing a vendor-supplier relationship. Unfortunately, the very kind of interrelationship between utility and subsidiary that would be necessary to fully realize synergies and economies of scope, pose major problems from a regulatory point of view, since extra vigilance is required to ensure that costs are being properly allocated between the utility and its subsidiary, and that the utility's ratepayers are not subsidizing the utility's investment. Thus the regulatory objective of preventing cross-subsidization can be at odds with the broader economic objectives of promoting the best (most efficient) use of society's resources. In many cases, it is understandable that where the risk of cross-subsidization posed by a given corporate structure is too great, the

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[29]"Economies of scope" refers to a property of cost functions where joint production of some set of products is less costly than producing them individually. Although economies of scope are most often associated with production technology, they can also result from managerial technology or shared managerial expertise. It is important for regulators to keep in mind that economies of scope result not from the nature of the investment <u>per se</u>, but from the resulting interrelationship and cooperation between the parent and its affiliate in the joint production process. Thus to the extent that the regulatory policies stifle or discourage a close working relationship between a utility and an affiliate, the ability of the utility and its affiliate to fully realize potential economies of scope is reduced. Commissions are therefore faced with two competing regulatory policies: that of promoting technological efficiency in the production and utilization of energy, and that of protecting the ratepayers from the risk of cross-subsidization. See generally, G. B. Enholm, T. M. Jaditz, and J. R. Malko, "Electric Utility Diversification in the 1980's: A Challenge for Applied Regulatory Economics," <u>Journal of Energy and Development</u>, 8 (Autumn 1982):124-125.

commission might choose to adopt a regulatory policy which effectively penalizes this type of interrelationship between the utility and its subsidiary.

Where economies of scope can be realized solely through the maintenance of a vertically-integrated vendor-supplier relationship--assuming the two operations are otherwise functionally independent--(i.e., there are no other shared costs, except those costs being minimized through the established vendor-supplier relationship), the risk of cross-subsidization (assuming transfer prices are properly monitored) would be outweighed by the overall benefits accruing from the economies of scope. In this case, state regulatory authorities might encourage such vertically integrated investments rather than discourage them by adopting a policy that denies the utility or its subsidiary the profits resulting from these synergies. Thus, a major problem with the utility-rate-of-return approach might be that it discourages utilities from investing in "related" or vertically-integrated industries, where possible economies of scope can be realized,[30] and instead encourages the utility to either invest wholly in unrelated ventures where there are no economies of scope or else to have its vertically-integrated subsidiaries sell a substantial portion of their output to nonaffiliated third parties.

This necessarily raises the issue of where does a regulator draw the line. Assuming that the utility-rate-of-return approach does have substantial justification when the subisdiary is in fact a public utility, where does a regulator draw the line to decide what is a functional part of the utility and what is not? For example, a regulator would probably wish to treat an electric utility subsidiary that provides transmission services

[30]The question arises why so many utilities continue to be actively involved in captive coal mine operations--despite the restrictive regulatory policies of a majority of respondents with respect to transfer prices. One possible explanation is that the benefits accruing to the utility--stemming from assured security of supply--outweigh the costs in terms of foregone profits on regulated affiliated transactions. Another explanation is that where a coal mine is profitable, the profits on nonregulated sales to nonaffiliated third parties compensate for the limited returns on sales to the affiliated utility--thus rendering the mining operation--on balance--an attractive investment from the utility's point of view.

as a part of the utility and would tend to regulate it as a utility for purposes of determining reasonable rates of return on affiliate transactions with the utility. A regulator would probably, but not necessarily, come to same conclusion for meter reading and billing services. In each case, the regulator would need to distinguish: (1) whether the subsidiary provides the utility services because of economics of scope implying that joint production is less costly than producing them separately, and (2) traditionally where has the utility performed this function. A regulator might want to discourage a utility from spinning-off subsidiaries that are in fact part of the utility since it might raise the cost of the service. If utility funtions are spun-off, then the utility-rate-of-return approach seems appropriate.

The application of the utility-rate-of-return approach to coal transfer prices might be inconsistent with the regulatory treatment of the utility's other nonregulated activities. As previously noted, the utility-rate-of-return approach is premised on the following principle: the subsidiary is, in fact, an extension of the public utility--therefore, its rate of return should be limited to that of the parent utility. However, state regulatory authorities may not always apply the same rationale to nonregulated below-the-line income generated by activities engaged in by the utility itself. Thus, for instance, if a utility was to engage in the retail sale of appliances as a nonregulated in-house business venture, then state commissions would not restrict the allowed rate of return from this nonregulated activity (assuming all costs were properly allocated between the regulated and non-regulated activities) but rather would simply subtract the capital committed to this nonregulated activity from the utility's rate base. With a coal-mining subsidiary, on the other hand, the commission would not only subtract the utility's investment from the rate base, but the commission presumably would limit the subsidiary's rate of return on any affiliate transactions with the parent utility.

It is hard to reconcile these apparently inconsistent policies. It could be argued that the coal mining subsidiary is no more a part of the utility than the utility's in-house nonregulated activities. Nor must the risk of cross-subsidy stemming solely from affiliate transactions between two separate functionally independent corporate entities exceed the risk of cross-subsidy inherent in the in-house operation of a nonregulated activity by the utility, requiring complicated cost allocation procedures and the possibility of casual cost transfers.

The utility-rate-of-return approach might be sub-optimal from an economist's point of view, because it is essentially a "cost-plus" standard. Utilities subject to this form of regulation may have little incentive to improve efficiency or reduce the costs of operations. As long as their costs plus the allowed rate of return are below the market price, there is no incentive for a captive mining subsidiary to further reduce costs, since this will not result in any increased profits. Thus the utility-rate-of-return approach could encourage inefficiency in coal production.

As with the profit-comparison test, some states applying the utility-rate-of-return approach often use a dual regulatory standard, imposing a market price ceiling on transfer prices. Thus the transfer price can be no greater than the prevailing market price for coal, even if this does not permit the subsidiary to recover its full costs of production.[31] While such a commission policy can be defended on the grounds of being reasonable (e.g., it would be unreasonable for the utility to buy coal at more than the prevailing market rate), assuming that the utility funded the investment solely out of its retained earnings, the policy could be viewed as unfair to the utility's shareholders on the grounds that under such a regulatory policy they must bear the sole risk of loss but are not able otherwise to realize a fair rate of return on their investment.

A fundamental principle of financial theory and "break-even analysis" is that the cost of capital is positively related to the elements of risk

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[31]See "Note, Captive Coal Pricing and the Regulation of Utility-Affiliate Transactions," 68 Virginia Law Review 1423 (1982).

involved.[32] Thus, the riskier a potential business venture, the greater the associated cost of capital, since the investor (and creditors) will demand a higher rate of return to justify the acceptance of additional risk. If a commission adopts the utility-rate-of-return approach, with a market price ceiling on transfer prices, the risk from that investment could be correspondingly higher than the risk associated with traditional utility operations, where the utility is assured recovery of all "reasonable" or "prudent" costs. Thus the proper rate of return for the utility's subsidiary would arguably be higher--since the risk of loss is correspondingly greater. Commissions applying the utility-rate-of-return approach, however, typically do not take this factor into consideration in establishing a "fair" rate of return for the subsidiary.

Application of Rate-of-Return Approaches

There are two issues generic to rate-of-return methods (i.e., either the profit comparison test or the utility-rate-of-return approach) which deal with how these methods are applied in practice. The first issue concerns how commissions determine the amount of the subsidiary's recoverable costs: i.e., does the commission use a "cost-plus" approach or does the commission base its cost estimates on a cost-of-service study? The second issue concerns the basis used for determining the subsidiary's allowed rate of return: specifically, is rate of return based on the book value or the fair market value of the subsidiary's plant, property, and equipment?

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[32] "[E]ach investment opportunity has its own individual cost of capital depending on its risk. So for purposes of evaluating investment opportunities, the cost of capital must be interpreted as a set of market-determined opportunity rates that vary with the risk." E. Solomon and J. Pringle, An Introduction to Financial Management, 2nd ed. (Santa Monica, Calif: Goodyear, 1980), p. 388.

One of the practical disadvantages of rate-of-return methods is in order to be most effective, they require an in-depth cost-of-service study. This is frequently infeasible when commissions lack access to the subsidiary's records and facilities. Even when commissions do have access to books and facilities, the staff may lack the requisite background or expertise in coal operations to adequately perform an in-depth cost of service study. Thus, according to a Department of Energy survey, nearly half of the respondents applying a rate-of-return method to captive coal transfer prices used a cost-plus pricing mechanism in applying this standard;[33] Moreover the survey authors estimate that a majority of the respondents purporting to use a cost-of-service approach, were in fact using a "cost-plus" approach.[34]

Under a "cost-plus" methodology, the subsidiary is allowed to recover all costs incurred plus the allowed rate of return. The "cost-plus" methodology is retrospective in application: under this method the commission need only determine which costs were actually incurred. With cost-of-service pricing, however, the transfer price of the subsidiary's product is regulated in the same manner in which a utility's cost-of-service is regulated: the transfer price is set at a level which will cover anticipated costs of production (based on a prior cost-of-service study) plus the allowed rate-of-return on capital. Thus the cost-of-service method is prospective in its application, since it is based on a commission's projections of the subsidiary's future production costs, rather than on costs previously incurred.

One of the major objections to cost-plus pricing is that it eliminates incentives for efficiency by the subsidiary. Since most or all of the costs are automatically passed on in the price of coal (subject only to the market-price limitation), there are few incentives to minimize production

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[33]D.O.E., Coal Competition: Prospects for the 1980's, p. 307.

[34]Ibid. See footnote 26 on that page.

costs.[35] Furthermore, earning a fixed rate of return would provide incentives for the subsidiary to over-capitalize or to pay inflated costs for capital in order to increase the investment base against which the rate of return is applied.[36] The Public Service Commission of West Virginia addressed this point in its comments on cases involving the Appalachian Power Company and two of its coal subsidiaries: Cedar Coal Company and Southern Appalachian Coal Company. The Commission stated:

> At this point it should be noted that a 9.8% or a 10.8% return on Appalachian's equity investment as part of a "cost-plus" price formula is entirely different than the return on rate base used in the making of specific unit rates for electric service. The "return on equity" in a coal price formula is not subject to attrition that sometimes occurs to the allowed "rate of return on rate base" used in setting utility rates. Moreover, the "return" element in "cost-plus" coal price is applied to a dollar base which can be expanded immediately and at will by Appalachian's additional equity investment (capital contributions) in its coal subsidiary to the maximum limits that have been allowed by regulatory bodies having jurisdiction. Such equity investment may be used for expansion which, even though it may be accounted for as Construction Work in Progress (CWIP), would realize (1) an immediate return to the coal company, (2) the potential for a higher price of coal to Appalachian and (3) the concomitant need for higher electric rates to offset deterioration of the earnings of Appalachian.[37]

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[35]Here, once more, the subsidiary will have some incentives to minimize production costs to the extent that it sells its products in the open market. However, if a subsidiary is "captive"--selling all or a substantial part of its output to its parent utility--it will have no incentive to cut costs if its costs plus allowed rate of return are already below the market price ceiling.

[36]This is particularly likely to occur in states where the subsidiary's permitted rate of return is based on a standard far in excess of its cost of embedded capital, e.g., an industry average, or the utility's rate of return on equity. See, e.g., D.O.E., Coal Competition: Prospects for the 1980's, p. 306.

[37]Public Service Commission of West Virginia Case Nos. 7930 and 8354, Appalachian Power Company transactions with Cedar Coal Company; Case Nos. 8358 and 8359, Appalachian Power Company transactions with Southern Appalachian Coal Company (quoted in D.O.E., Coal Competition: Prospects for the 1980's, p. 307).

The advantage of cost-of-service pricing, therefore, is that it provides the captive subsidiary with some incentives to operate efficiently, since the subsidiary's allowed rate of return is based on anticipated rather than historical costs of production. Thus, if actual production costs are lower than anticipated, the rate of return actually earned by the subsidiary will be higher (and vice-versa). Use of a cost-of-service standard would also mitigate the tendency of regulated firms to over-capitalize, since regulatory officials would have an opportunity to examine the propriety of various additions to the subsidiary's "rate base" in the course of the cost-of-service study.

The second issue relating to the application of rate-of-return methods concerns the correct basis for applying the standard, i.e., whether the rate of return should be calculated using the book value or the fair market value of the subsidiary's assets. In past cases where this standard has been applied, state commissions have valued the subsidiary's assets at book value (i.e., original cost less depreciation).[38] However, if the subsidiary charges the same price as independent producers, the rate of return computed on the book value of the subsidiary's assets will reflect not only the costs associated with its current operations, but also past changes in the market value of those assets. Because of the changes in the market value of assets, the length of time that a subsidiary has been in business may have more impact on its rate of return when computed on original investment than the cost of its current operations. For example, if two mining companies with the same operating costs and identical assets were operating for a different length of time, the older company, which presumably paid less for its coal leases, would have a higher rate of return. The higher rate of return would be solely the result of past appreciation in the market value of assets.[39]

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[38]"Note, Captive Coal Pricing and the Regulation of Utility-Affiliate Transactions," p. 1427, n. 92.

[39]Ibid., p. 1427.

Should an application of the profit comparison test reduce an older subsidiary's transfer prices below those charged by independent producers in order to reduce its rate of return, the older subsidiary would be prevented from selling its output at the market price, which is related to the current value of its assets, and would instead be limited to a transfer price based on the original cost of those assets. The subsidiary's owners would not benefit from the appreciation in the subsidiary's assets; instead any appreciation would be transfered from shareholders to the ratepayers in the form of decreased rates.[40] The utility and its subsidiary would have an incentive to circumvent these regulatory restrictions in one of two ways: (1) the subsidiary might discontinue sales to its regulated parent and sell only to nonaffiliated buyers at the prevailing market price; or (2) the utility might divest itself of its investment in the subsidiary altogether.

The problem with the rate-of-return approach as applied to the book value of the subsidiary's assets is that it creates disincentives for the utilities to invest in related areas--such as fuel production--when the book value of the subsidiary's assets is substantially below the fair market value. A preferable approach, therefore, may be to use the fair market value of the subsidiary's assets--rather than the book value--as a basis for the profit comparison test. If the subsidiary's assets are valued at fair market value instead of original cost, the rate of return permitted to the subsidiary should be set so that it does not adjust for inflation. In other words, the rate of return should correspond to the "real" interest rate rather than the "nominal" rate. To permit subsidiaries to both earn a return on the current value of their assets and to use a rate of return that includes the current inflation rate would be double compensation for inflation. Since firms are required under FAS #33[41] to state their balance sheets at fair market value, this should not be a difficult standard to apply in practice.

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[40]Ibid.

[41]Financial Accounting Standards Board, Statement of Accounting Standards No. 33, Financial Reporting and Changing Prices (Stamford, Conn.: F.A.S.B., 1979).

APPENDIX A
HISTORICAL PERSPECTIVE

This appendix provides a brief history of the regulation of electric utility diversification since the late nineteenth century. Legal history and authorities, the exercise of that authority by regulators and the abuses leading to the passage of the Public Utility Holding Company Act of 1935 are covered.

In 1888 New Jersey modified its general stock corporation law to allow a corporation formed under the law to hold the stocks of other corporations. New Jersey was the first state to take such action, and it was an important step. Under common law, one company was not permitted to own the stock of another except as a first step in a merger or as a debt payment. The rationale was that a company's stockholders had not intended the company to invest resources in a new and distinct enterprise and the purchase of the second company's stock involved such an investment. As a result of this legal reasoning, holding companies with major operations prior to 1888 operated on the basis of special legislative acts. Holding companies were rare as a form of corporate organization.

The change in the New Jersey statute attracted businesses to incorporate in that state. Other states followed New Jersey's lead so that by 1929 thirty-nine states had made similar changes in their laws with several additional states having court rulings sympathetic to inter-corporate stockholdings.[1]

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[1]See James C. Bonbright and Gardiner C. Means, _The Holding Company: Its Public Significance and Its Regulation_ (New York: McGraw-Hill Book Company, Inc., 1932), pp. 55-57; and Douglas W. Hawes, _Utility Holding Companies_ (New York: Clark Boardman Company, Ltd., 1985), pp. 2-2 - 2-4. The amendment allowed a corporation to purchase the stock of any other company owning or producing materials or property that the first company needed for its business. The acquiring business was also authorized to issue its stock as payment for the purchase. See U.S., Congress, Senate, _Utility Corporations: Report of the Federal Trade Commission to the Senate of the United States_, S. Doc. 92, 70th Cong., 1st sess., 1935, pt. 73A, pp. 8-9. The FTC report notes (p. 10) that part of the motivation for the states changing their laws to allow intercorporate stockholding was the desire to obtain incorporation fees and annual franchise taxes from the holding companies.

The formation of holding companies was not widespread immediately following the passage of these new statutes by New Jersey and other states. Bonbright and Means state in their book on holding companies that

> For some years, only a few corporation lawyers... were bold enough to advise their clients to try out the new and legally untested statutes permitting one corporation to own the stock of another corporation. Outright fusion, rather than the holding company, was therefore the usual mode of combination during the nineties....[2]

After the turn of the century, holding companies became more common.

From 1900 to the Depression, many utility holding companies were established by "all manner of founders, from banks and engineering firms to promoters who knew little about the utility business and whose principal aim seems to have been a promoter's profit."[3] More and more electric utilities became parts of holding company systems. Some holding companies merged, and in some instances holding companies were established over other holding companies. By 1932 three holding companies (Electric Bond & Share Group, Insull Group, and United Corporation) controlled roughly 49 percent of the investor-owned electric utility industry. The next twelve largest holding companies controlled an additional 35 percent of the industry.[4]

Bonbright and Means note that two economic reasons for the establishment of these public utility holding companies were that the large holding company systems were stronger financially than local utility operating companies and that only large holding companies could obtain the efficiency and economy of centralized management or supervision by an organization of highly skilled experts. The authors noted that these two motivations for holding company establishment were advantageous to the public as well as opportunities for profits. However, they state that "it is a serious

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[2]Bonbright and Means, The Holding Company, p. 65.

[3]Hawes, Utility Holding Companies, p. 2-4.

[4]Ibid., pp. 2-4 - 2-5. See pp. 2-5 to 2-11 for a discussion of the three largest holding companies. See also Bonbright and Means, pp. 98-113, 127-138 for a discussion of these three holding companies.

question whether other and less legitimate motives have not so determined the extent and nature of utility combinations, that the public advantages of the holding company have been largely offset by disadvantages."[5]

Bonbright and Means also expressed concern about the freedom of utility holding companies from regulation by state utility commissions. The authors noted that such freedom was a "serious menace--a menace so great that it threatens the whole American scheme of private ownership under governmental regulation."[6]

Utility holding companies did present some major difficulties for state regulators. A report by the Federal Trade Commission (FTC) on utility holding companies, issued in ninety-five volumes from 1928 to 1935, discussed the problems posed for state utility commissions. For example, the FTC report stated that twenty-eight states (contrasting with the thirty-nine states reported by Bonbright and Means) and three territories allowed one corporation to own the stock of another corporation. However, in twenty-five of these thirty-one states and territories regulators had no control over the holding companies that were organized as a result of those statutes. While a few states had laws that attempted to regulate holding companies, other states attempted to control the holding company through regulation of its utility subsidiary. In the latter states, a holding company would have to meet any requirements specified by the state utility commission before the utility operating company could obtain rate relief from the commission. But the report notes that:

> this method has the obvious disadvantage of indirection and the further drawback that ordinarily it can be applied only when the operating company comes before the regulatory body seeking some relief. Moreover, the regulatory commission usually meets jurisdictional difficulties in any effort to ascertain the costs of

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[5]Bonbright and Means, The Holding Company, p. 93.

[6]Ibid.

holding or other affiliated companies under their service and sales contracts.[7]

The jurisdictional problem mentioned here was a major obstacle for state regulators and, as seen below, it was noted elsewhere in the FTC's report.

Monitoring transactions between a utility and its holding company parent or another of the holding company's affiliates presented problems for state regulators. One such problem was that the utility did not always provide the state commission with necessary information on the costs to the holding company parent or affiliate of the goods or services provided to the utility in the affiliate transaction. The FTC report noted that state regulators may have needed to assess the value of a holding or an affiliated company's property in order to determine the costs to it of furnishing the goods and services provided to the utility. However, the holding company or the affiliated company that was involved in the transaction with the utility may have been outside the jurisdiction of the state utility commission, and the commission could then not require the company to furnish the necessary information.[8]

Affiliate transactions between a utility and its holding company parent presented other problems for state commissions. While a commission might not permit a particular charge by a holding company (or an affiliated company) to the utility to be included in the utility's rates, the commision could not prevent the utility from still paying the charge. Paying the charge would inflict the loss upon the utility's stockholders, resulting in potential harm not only to those individuals, but also to the utility's credit.

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[7]U.S., Congress, Senate, Utility Corporations, pt. 73A, p. 2. The difference in numbers of states reported by the FTC and by Bonbright and Means as allowing one corporation to own the stock of another is apparently due to the FTC's total including only states that placed no restrictions on the right of a corporation to own the stock of another. See p. 9 of pt. 73A of the FTC's report.

[8]Ibid., p. 25.

The FTC noted that some states had enacted statutes giving the state utility commission authority to review contracts between a utility under its jurisdiction and any companies affiliated with the utility. State regulatory review was required before a contract could go into effect. Some state commissions were also given the authority to gain access to the books and records (of both the utility and the affiliated company) that would be needed to review affiliate transactions involving a utility. However, state commissions often did not have the power to require a holding company or its affiliated companies to keep a uniform system of accounts. The lack of such authority was an important limitation on a commission's contract review power. In addition, the books and records of a holding company were often located in another state, making it difficult for a commission to gain access to them.[9]

State utility commissions faced jurisdictional problems in cases in which holding companies acquired utilities, particularly at excessive prices. The FTC report noted the existence of a body of administrative law designed to protect the public interest during such acquisitions but "which cannot be said to accomplish that end to any effective extent."[10] A state commission often did not have authority over a holding company acquiring a utility within its state because the holding company was located in another state. Because of the holding company's location elsewhere, the utility commission was not able to gain access to its books and ensure that the excessive price paid by it for the utility was not charged to property accounts or included in operating expenses (and thus included in rates).

The FTC noted other limitations on state regulatory powers during this era. As noted above, state utility commissions often would not require that a uniform system of accounts be kept. Fourteen jurisdictions (including states, territories, and possessions) had no statutory provisions

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[9]Ibid., pp. 25-26.

[10]Ibid., p. 3.

requiring a uniform system of accounts to be kept by all public utilities. In those areas with such a requirement, the FTC noted that the statutes were so vague that they did not indicate the extent to which there was actual regulation of the accounts.[11]

The FTC report discussed some causes of the jurisdictional problem faced by the state regulators. It noted that some states allowed corporations almost unlimited privileges in their charters to persuade those companies to incorporate there. In addition, in some instances corporations were authorized to conduct business only in states other than the one in which they were incorporated. The FTC found that the states were very permissive of corporations formed under the laws of one state doing business in all of the others.

Complicating the problems created by the generous grants of privileges in corporate charters and the permissive attitude of states toward outside corporations doing business within their boundaries was the prohibition against one state exercising its authority, including regulatory authority, within the borders of any other state. The result, according to the FTC, was that effective regulation of the holding companies by state utility commissions was made impossible by numerous conflicts and contradictions between the states.[12]

Other problems for state regulatory authority came from federal preemption of jurisdiction. The U.S. Constitution granted Congress authority over interstate commerce. This federal authority has been interpreted (and expanded) to include intrastate transactions that have a significant impact on interstate commerce. The FTC noted that conflicts of jurisdiction between the federal government and a state could easily occur, and that a utility could avoid state regulation by moving some of its operations across state boundaries. The report noted that both electric

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[11]Ibid., pp. 3-4.

[12]Ibid., pp. 4-5.

and natural gas utilities had sought to hinder state regulators by arguing that they were engaged in interstate commerce.[13]

Another problem with state utility regulation at that time was its lack of supervision of the utilities' security issuances. The FTC found that in twenty states there were no statutes specifically dealing with the regulation of utility security issuances. In addition, the state commissions often interpreted their authority in this area in a restrictive manner. The absence of effective regulation of utility securities resulted in overcapitalization because the prices paid for the securities were based on inflated valuations by the utility of its own property.[14]

The FTC report and studies made by various states and by the U.S. House of Representatives Interstate and Foreign Commerce Committee focused attention in the early 1930s on the problems created by the utility holding companies. President Franklin D. Roosevelt proposed legislation that was ultimately enacted as the Public Utility Holding Company Act of 1935. (Roosevelt wanted to restrain the utility holding companies, if not totally eliminate them.) Holding companies were required to register with the Securities and Exchange Commission (SEC), the agency charged with enforcing the PUHCA, and provide that Commission with whatever information and documents that it may decide were needed to protect the public interest or the interests of investors or consumers. Section 11 of the PUHCA does limit a holding company to a single integrated public utility system (although in certain instances a holding company may have additional

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[13]Ibid., pp. 5, 7-8. The report notes that in twenty-two cases in twelve states, from 1891 to the time of the report (1935), natural gas utilities had thwarted attempted state regulation by arguing that the state was interfering with interstate commerce. The result of the courts ruling against the states in those cases was that the utilities were left unregulated in the areas involved in the disputes. The report notes that there were not as many cases involving electric utilities, but that those found "illustrate the desire of the industry to free itself from State regulation where it could do so." See ibid., pp. 7-8.

[14]Ibid., pp. 13-16. See also Bonbright and Means, The Holding Company, pp. 159-163.

utilities within its system) and only those other businesses that are "reasonably incidental, or economically necessary or appropriate to the operations of" the integrated public utility system. The PUHCA applied only to electric and gas utilities. As noted in chapter 1, a holding company that was mainly intrastate, (i.e., its operations and those of its subsidiaries are conducted substantially in a single state in which the company and its subsidiaries were organized), could be exempted from the provisions of the law by the SEC. It was felt that the intrastate holding companies could be regulated adequately by the state utility commissions.[15]

The SEC did not begin the process of simplifying the holding company systems until 1938. The Holding Company Act mandated a three-year delay in its implementation. By 1955, much of the task of reorganizing the registered holding company systems had been accomplished. During this period of reorganization the number of registered holding companies was reduced from 214 (controlling 922 electric or gas utilities and 1,054 nonutility companies) to 25 (controlling 171 electric and gas utilities and 137 non-

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[15]See Hawes, Utility Holding Companies, pp. 2-15, 2-18; Aaron Levy and Douglas W. Hawes, "Holding Company Act Implications," in Utility Diversification: Strategies and Issues (New York: Public Utilities Reports, Inc. and The Management Exchange, Inc., 1981), pp. 34-35; and the Public Utility Act of 1935, Title I, Sections 2(a)(5), 3(a)(1), 5, and 11(b)(1). The Public Utility Holding Company Act was Title I of the Public Utility Act. It is in Title 15 of the U.S. Code at 15 U.S.C. §79-79z-6. Section 3 (a)(2-5) of the Act lists the other qualifications for exempt holding companies. See footnote 1 and the text in chapter 1 for a discussion of those exemptions. Section 11(b)(1)(A),(B),(C) listed the conditions under which a registered holding company could control more than one public utility system. Those conditions included that the additional systems to be controlled by the holding company could not operate as independent entities without losing substantial economies and that the additional systems were located in one state or in adjoining states. In limiting a registered holding company to controlling only those additional businesses (other than its public utility system(s)) that are reasonably incidental or economically necessary or appropriate, the Act adds in section 11 (b)(1)(C) that the SEC may allow as meeting this requirement any business which it finds necessary or appropriate in the public interest.

utility companies).[16] As of December 31, 1984 the SEC reported that there were 13 registered holding company systems (10 electric, 3 natural gas) controlling 65 electric and gas utilities and 72 nonutility businesses.[17]

While the number of registered holding companies has declined, the number of exempt holding companies, as discussed in this report, has increased. Many of these companies emerged from reorganization proceedings under the Public Utility Holding Company Act, and many of them have been formed mainly for the purpose of diversification.[18]

In reviewing this history of events since New Jersey modified its corporate law in 1888, one can see that state regulators faced major obstacles during the holding company era. Any type of effective regulation ultimately had to come from the federal government under the Public Utility Holding Company Act of 1935. However, many of the issues raised earlier in this century, including regulation of affiliate transactions and access to necesssary books and records, are still alive and continue to confront state utility commissions as they regulate electric utilities with subsidiaries.

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[16]Hawes, Utility Holding Companies, p. 2-18. Hawes also notes some SEC data (on pp. 2-18 and 2-31, n. 52) that between 1935 and 1955 registered holding companies divested 839 subsidiaries with aggregate assets of about $13 billion. This total included 260 electric utilities with over $9 billion in assets, 162 gas utilities with assets of about $1.5 billion and 417 nonutility companies with $2.2 billion in assets. For an account of the reorganization of one holding company, see U.S., Congress, Senate, Select Committee on Small Business, The Public Utility Holding Company Act of 1935: Report of the Securities and Exchange Commission to the Subcommittee on Monopoly of the Select Committee on Small Business, Subcommittee Print No. 4, 82d Cong., 2d sess., 1952, pp. 9-16.

[17]U.S., Securities and Exchange Commission, Division of Investment Management, Office of Public Utility Regulation, Financial and Corporate Report Registered Public Utility Holding Company Systems, December 31, 1984, p. 9.

[18]Hawes, Utility Holding Companies, pp. 2-24 - 2-26.

APPENDIX B
SURVEY INSTRUMENT AND RESPONSES

This appendix contains a compilation of the state commission responses to the National Regulatory Research Institute's survey on commission treatment of electric utility subsidiaries.

Senior staff members of forty state commissions responded to the survey questionnaire. The senior staff members of the forty commissions are Mr. Charles B. Stults of the Alabama Public Service Commission (AL), Mr. Wayne E. Ruhter of the Arizona Corporation Commission (AZ), Mr. Jerrell Clark of the Arkansas Public Service Commission (AR), Mr. Bruno A. Davis and Mr. James D. Pretti of the California Public Utilities Commission (CA), Mr. Harry A. Galligan, Jr. of the Colorado Public Utilities Commission (CO), Mr. Barney E. Spector of the Connecticut Department of Public Utility Control (CT), Mr. E. Dennis Maczynski of the Delaware Public Service Commission (DE), Mr. James E. Kerr of the District of Columbia Public Service Commission (DC), Mr. David L. Swafford of the Florida Public Service Commission (FL), Mr. Horace F. Hartley of the Georgia Public Service Commission (GA), Mr. Melvin S. Ishihara of the Hawaii Public Utilities Commission (HI), Mr. Archie L. Holbert of the Idaho Public Utilities Commission (ID), Ms. Donna Martin of the Illinois Commerce Commission (IL), Mr. James Armstrong of the Kansas State Corporation Commission (KS), Mr. Gary Forman of the Kentucky Public Service Commission (KY), Mr. Louis S. Quinn of the Louisiana Public Service Commission (LA), Ms. Elizabeth Paine of the Maine Public Utilities Commission (ME), Mr. Harold Bertolucci of the Massachusetts Department of Public Utilities (MA), Mr. James A. Mendenhall of the Michigan Public Service Commission (MI), Mr. Randall Young of the Minnesota Public Utilities Commission (MN), Mr. C. Keith Howle of the Mississippi Public Service Commission (MS), Mr. Kevin Thomas Kelly of the Missouri Public Service Commission (MO), Mr. Jim Watson Montana Public Service Commission (MT), Mr. Michael J. Griffin, Sr. of the Nevada Public Service Commission (NV), Mr. Wayne E. Arnold of the New Hampshire Public Utilities Commission (NH), Mr. Anthony J. Zarillo of the New Jersey Board of Public

Utilities (NJ), Ms. Marilyn O'Leary of the New Mexico Public Service Commission (NM), Mr. John J. Kelliher of the New York Department of Public Service (NY), Mr. Joseph W. Smith of the North Carolina Utilities Commission (NC), Ms. Janet A. Elkin of the North Dakota Public Service Commission (ND), Mr. David Hodgden of the Ohio Public Utilities Commission (OH), Mr. Joe Sand with the Oregon Public Utility Commissioner (OR), Dr. Donald L. Birx and Mr. G.J. Gillert of the Pennsylvania Public Utility Commission (PA), Mr. Wayne Burdett of the South Carolina Public Service Commission (SC), Ms. Roberta Lovald of the South Dakota Public Utilities Commission (SD), Mr. Richard Bibb of the Tennessee Public Service Commission (TN), Ms. Marilyn Neff of the Texas Public Utility Commission (TX), Mr. Carl L. Mower of the Utah Division of Public Utilities (UT), Mr. David Rees of the Washington Utilities and Transportation Commission (WA), and Mr. Todd Carden of the West Virginia Public Service Commission (WV). Because the survey questionnaire was answered by a member of each commission staff, the reader should keep in mind that the responses do not necessarily reflect the views of a commissioner on the topic.

Two of the state commissions that responded to the survey questionnaire did so by means of a letter, which described their commission's authority over the establishment of electric utilities and other survey areas. These commissions are the Louisiana Public Service Commission and the Mississippi Public Service Commission. The Tennessee Public Service Commission telephoned in their response to the survey. The responses from these commissions have been integrated with those of other responding state commissions.

The compiled responses to the surveys are set out in this appendix on a question-by-question basis. First, each question (including its introductory comments and instructions) is set out and then, for the most part, the responses to the survey given by each state commission staff are provided on a state-by-state basis, in alphabetical order. However in some instances many of the states responded to several of the questions with "not applicable" or "no answer." For each of the questions, those states giving the answer of "not applicable" or "no answer" are grouped together at the end. The survey questions and answers follow.

I. First, we would like to know about the extent of your commission's authority over the establishment of electric utilities' subsidiaries and affiliates. If your answer to the first part of question #1 is "no", please answer only questions 5, and 14 through 24.

1. Does your commission have authority to approve or disapprove the establishment by electric utilities of subsidiaries and affiliates? __________ If so, how many requests to establish subsidiaries and affiliates has your commission considered within the last ten years? __________ How many were approved? __________ How many were disapproved? __________ How many requests are still pending? __________ What are the reasons electric utilities give for wanting to establish separate companies?

AL -- No.
AZ -- No.
AR -- No.
CA -- No.

CO -- No, unless the subsidiary and affiliate companies also are utilities. In those instances, the subsidiaries or affiliates would be subject to the same regulation as the parent company.
CT -- No.
DE -- No.
DC -- No.
FL -- No.
GA -- No.

HI -- Yes. Note: This jurisdiction has an electric utility that has two subsidiaries engaged in the same type of business, i.e., electric utility, providing service in different areas. We assume that the survey is directed to subsidiaries or affiliates engaged in nonutility businesses.
No requests.

ID -- No.

IL -- Yes.
7 requests.
7 approved.
0 disapproved.
0 pending.

Reasons given by the utilities for wanting to establish separate companies: to augment the supply of gas available from pipeline suppliers, to allow the utility to expand into business ancillary to its electric utility business, to establish foreign markets, and to finance nuclear fuel requirements.

KS -- No.

KY -- No.

LA -- Yes. This Commission is constitutionally created, and its substantiative powers to regulate public utilities are found in the Constitution itself. Consequently, there is little statutory law concerning electric utility vis-a-vis subsidiaries. As a general practice, electric utilities doing business in Louisiana have customarily sought the approval of the Commission on a case-by-case basis where significant dealings with a subsidiary are involved. Such cases might be a reorganization, or the creation of a subsidiary for some specific given purpose. Because of the commission's consitutional basis, the commission has very comprehensive powers to approve or disapprove of virtually any utility arrangement which might bear upon the ability of the utility to render adequate service, or which might result in a change of rates.

MA -- For all of our electric companies of a holding company system, the holding company can form subsidiaries at will subject to any SEC requirement. After formation if any subsidiary has any transactions with one of the operating electric utilities it is required to file an annual return with the Massachusetts Department of Public Utilities ("Department"). The Department can exercise jurisdiction over the subsidiary only to the extent of the transactions between it and any other affiliated company.

If the utility is not a holding company but an operating utility then the utility is required to get approval of the Department to establish such a company. For example, Boston Edison Company (which is an operating utility and not a holding system member) was permitted with the approval of the Department to form a nuclear fuel financing subsidiary. Boston Edison Company tried to form a holding company for diversification purposes, but was denied by the Department primarily because they submitted no detailed plans.

MS -- Yes.
0 requests.

MI -- Uncertain. Never fully tested in the courts.

MN -- No.
MO -- No.

MT -- Uncertain. This is untested in Montana at the present time and these questions on commission authority cannot be answered. A bill was recently introduced in the legislature, but died on the floor of the House. The bill would have clarified and established the authority of the Montana commission over the utilities subsidiaries. There has also been recent litigation between the commission and at least two utilities concerning subsidiaries and holding companies, no outcome of this litigation is yet at hand.

NV -- No.

NH -- Yes. 8 requests.
8 approved.
0 disapproved.
0 pending.
Reasons given by utilities for wanting to establish separate companies: to separate areas of responsibilities, to identify responsibilities by task organization, to separate regulated from unregulated enterprises, and to improve technical expertise.

NJ -- No.

NM -- No. However, the commission has certain specified authority to examine the books and records of business entities that are affiliates of public utilities. In 1982, a law was enacted that placed a moratorium on diversification activities by public utilities. An interim legislative committee was established to study the diversification issue and the commission was ordered to adopt regulations governing diversified activities by November 30, 1982; the commission adopted General Order No. 39. In 1983, the legislature allowed the moratorium to expire.

NY -- Yes, to the extent that the electric utility uses utility revenue to directly provide funds for or guarantee the debt of the subsidiary or affiliate.
8, excluding 4 requests that were subsequently withdrawn.
8 approved.
1 disapproved.
0 pending.

The specific reasons electric utilities give for wanting to establish separate subsidiaries such as the one formed by Niagara Mohawk Power Corporation are
(a) it protects the ratepayer,
(b) it gives the proper incentives to the management in the subsidiary to be productive, and
(c) it helps to ensure the development of cost-effective energy resources in the State.

Orange & Rockland justified its entering the real estate business on the grounds that it would be able to enhance the development of real estate in its area, thereby increasing the load on its system which would reduce the fixed costs borne by other ratepayers.

Other utilities invested in uranium ventures to secure uranium at a reasonable price. Still others, such as Central Hudson's "CH Resources" have cited tax, legal and administrative reasons.

NC -- No.
ND -- No.
OH -- No.

OR -- Yes.
We can't answer the questin of how many requests to establish subsidiaries and affiliates has the commission considered, without exhaustive research.
Most applications have been approved.
Very few requests have been rejected. One application was recently rejected because the utility did not accurately record its costs.
Utilities claim that in some way costs will be reduced for ratepayers.

PA -- No. Note: the Commission does not have direct statutory authority to approve or disapprove establishment of subsidiaries and affiliates by electric utilities. However, if a regulated utility has to issue securities to accomplish the transaction, the Commission has authority to approve or disapprove securities applications. Grounds for disapproval would probably have to be based upon indications that the utility's financial health would be endangered so that it could not provide safe and adequate service.

There is currently an open investigation docket under which the Commission is examining diversification. It will be determined whether additional legislation or regulations are needed.

SC -- No.
SD -- No.
TN -- No.
TX -- No.

UT -- Yes.
1 considered.
1 approved.
0 disapproved.
0 pending.

The reasons given by the utilities for establishing a separate subsidiary company were to develop cogeneration, small power production, and geothermal power production facilities and projects as authorized by PURPA or to enter other areas related to energy development and conservation.

WA -- Approval to establish a subsidiary or affiliate is indirect. Commission approval is only required if assets used in providing utility services to the public are being transferred to the new subsidiary from the electric utility. In the same manner, if a utility was being restructured so that the voting common stock of the utility was being exchanged for all the stock of a new holding company, this new relationship would have to be approved if any new stock was being issued by the utility or any of its assets were being transferred to a subsidiary or holding company.
2 considered.
1 approved.
0 disapproved.
1 pending.

WV -- No.

2. If your commission has authority to approve or disapprove the establishment by electric utilities of subsidiaries or affiliates, what procedure does the commission use? Is there a separate hearing or application devoted to the establishment of the subsidiary or affiliate? Is the request considered as part of a securities issuance proceeding?

HI -- The procedure would be the filing of an application by the regulated utility to seek approval to establish a subsidiary or affiliate and the purposes thereto. Inasmuch as the capital structure of the regulated utility may be affected, the issue of financing or securities issuance may be a factor in the proceeding.

IL -- A company must file for Commission approval to establish a subsidiary. According to Section 27 of the Public Utilities Act, "unless the consent and approval of the Commission is first obtained or unless such approval is waived by the Commission in accordance with the provisions of this Section:" (Subsection g.) "No public utility may use, appropriate, or direct any of its moneys, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or diversification essentially and directly connected with or a proper and necessary department or division of the business of such public utility.

The request may be considered as part of a securities issuance proceeding. Section 27, subsection h, states "No public utility may, directly or indirectly, invest, loan or advance, or permit to be invested, loaned or advanced any of its moneys, property or other resources in, for, in behalf of or to any other person, firm, trust, group, association, company or corporation whatsoever."

LA -- On a case-by-case basis. The commission has traditionally dealt with the majority of utility issues raised by subsidiaries through individually processed cases, which might include, for instance, a rate case.

ME -- The commission treats the cases concerning the approval or disapproval of the establishment of subsidiaries and affiliates just as it does any other case.
Yes, there is a separate hearing or application devoted to the establishment of the subsidiary or affiliate.
No, the request is not considered as a part of a securities issuance proceeding.

MA -- This Commission has the authority to approve or disapprove the formation of subsidiaries by operating utilities. They usually have hearings. They may conduct separate hearings if securities are going to be issued by the parent company to finance the subsidiary.

MS -- Because there have not been any request for such establishment, the Commission has not adopted or promulgated policy and procedures for dealing with subsidiaries and affiliates.

MO -- Reference: Missouri Public Service Company's acquisition of Kansas Public Service Company. Approval as requested by the Missouri Public Service Company to issue common stock in exchange for the common stock of the Kansas Public Service Company.

NH -- Contract with affiliates which exceed $500 must be filed within ten days after the contract is executed. The Commission has authority to investigate and, at its option, may require hearings. The hearing is devoted specifically to the contract at issue. The request is not considered part of a securities issuance proceeding.

NY -- The utility files a petition with the Commission pursuant to a set of Rules of Procedure. The proceeding is subject to public hearings but they are usually waived. The request is not usually considered in conjunction with any securities being issued. In fact, our law does not allow approval of the issuance of securities for nonutility purposes. Thus, investments in subsidiaries are typically funded from the "retained earnings" and cash of the utility.

OR -- They have to file an application with us.

UT -- A separate hearing was held for the establishment and financing of the subsidiary.

WA -- The issuance of securities or any transfer of utility property are usually handled by application with final consideration thereof at a regular weekly open meeting of the Commission. However, the Commission always has the right to set the matter for public hearing.

AL, AZ, AR, CA, CO, CT, DE, DC, FL, GA, ID, KS, KY, MI, MN, MT, NV, NJ, NM, NC, ND, OH, PA, SC, SD, TN, TX, WV -- No answer or not applicable.

3. Does your commission formally consider either a) the appropriateness of electric utilities having any subsidiaries or affiliates or b) the appropriateness of electric utilities having subsidiaries or affiliates of particular business types? If so, what methods does your commission use to make this determination? Does your commission periodically reassess the appropriateness of the subsidiaries and affiliates, or is the assessment made only when the subsidiary or affiliate is being established?

HI -- Inasmuch as no application has been filed, we are not able to respond to the inquiry. However, most of the questions would be pertinent in the proceeding. If application is granted, it would behoove the agency to exercise continuous surveillance of the operations of the subsidiary or affiliate as it affects the operations and well-being of the regulated company.

IL -- The Illinois Commerce Commission considers the appropriateness of electric utilities having subsidiaries and affiliates through Section 27(g) of the Public Utilities Act. Section 27(g) requires the utility to obtain Commission approval prior to using, appropriating, or directing any of its money, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or division essentially and directly connected with or a proper and necessary department or division of the business of such public utility. The appropriateness of the subsidiary is reviewed or reassessed during subsequent rate increase proceedings.

ME -- Yes. The Commission determines whether it is in the ratepayers best interest. Not enough history to comment on periodic reassessment.

MA -- If an operating utility is going to form a subsidiary (not a holding company) the Commission does consider the appropriateness but we have had no occasion to exercise this.

MO -- No.

NH -- Yes to (a) and yes to (b). The burden is on the Company to show why the subsidiary or affiliate is in the public interest. Reassessments are made during rate proceedings and are subject to review at any time.

NM -- No.

NY -- The Commission considers, generally, whether the utility should have an affiliate as well as the appropriateness of the particular business being proposed.

In cases of electric utilities, the business that the proposed subsidiary or affiliate is engaged in has been related to the operating of the electric utility or maintaining better load characteristics. Our key focus is the extent of the financial burden placed on the utility by the formation and operation of the subsidiary or affiliate.

OR -- We review the affiliate interest applications, which are normally approved without public hearings.

We are currently studying the subsidiary/affiliate structure of all our large utilities.

UT -- The hearing considered the type of activity that the subsidiary would engage in and the proper relationship between the utility and its subsidiary.

No formal procedures were established for periodic review of the appropriateness of the subsidiary, only its ongoing relationship with the utility as it affects the utility's operations.

AL, AZ, AR, CA, CO, CT, DE, DC, FL, GA, ID, KS, KY, LA, MI, MN, MS, MT, NV, NJ, NC, ND, OH, PA, SC, SD, TN, TX, WV -- No answer or not applicable.

NOTE TO QUESTIONS 4 AND 5: We would be interested in having as much information beyond that requested in questions 4 and 5 as you might be able to furnish. This would include (1) the name of the various subsidiaries and affiliates, (2) the relationship of a company to the electric utility (i.e., wholly owned subsidiary, affiliate jointly owned with another utility or company, affiliate and utility which own each other, or affiliate and utility under the same holding company), (3) the proportion of utility profits contributed by a subsidiary, and (4) the size (in monetary terms) of the subsidiary or affiliate relative to the utility. All such information would be useful to our study. As you furnish this information, please use the business classifications found in questions 4 and 5. Also please make the distinction, as in questions 4 and 5, between those subsidiaries and affiliates the establishment of which is under your commission's authority and those which are not. Please attach additional pages if necessary.

4. Into what fields of business have the expansion efforts by electric utilities under your commission's authority been directed? How many subsidiaries exist in each of the following categories of business? For each business type, please list the name of each electric utility involved and the number of subsidiaries and affiliates that it has. (Please list only the subsidiaries and affiliates the establishment of which is under your commission's authority. The next question deals with subsidiaries and affiliates that are <u>not</u> under your commissions's authority.

IL -- <u>Fuel Exploration and Development</u>: Illinois Power - 2; Commonwealth Edison - 4
<u>Real Estate</u>: Interstate Power Company - 1
<u>Short Line Railway</u>: Commonwealth Edison - 2
<u>Other (please specify)</u>: Commonwealth Edison - 2 (insuring casualty risk, and research and development)

Detailed information follows.

The following electric utilities in Illinois have subsidiaries. The subsidiary's business type and relationship to the utility is also outlined.

A. Illinois Power Company

1. Illinois Power Gas Supply Company

100 percent of the voting common stock is owned by Illinois Power. The subsidiary was established for the purpose of acquiring interests in gas and oil leases. Illinois Power Company, through such investment, is attempting to increase the supplies of gas available to it through its pipeline supplier, Natural Gas Pipeline Company of America, by participating together with a subsidiary of Natural Gas Pipeline Company of America and other gas distribution utility customers of such pipeline supplier in the acquisition of such leases.

2. IPF (Illinois Power Finance) Company, N.V.

100 percent of the voting common stock is owned by Illinois Power. IPF was established for the purpose of borrowing funds outside of the United States.

3. 50 percent of the voting common stock is owned by Illinois Power. The subsidiary was formed to finance Illinois Power's nuclear fuel requirements.

B. Interstate Power Company

1. IPC Development Co.

100 percent of the voting common stock is owned by Interstate Power. IPC Development Co. is presently taking title to land on a temporary basis. Future business may include taking title to or leasing coal cars, obtaining coal transloading facilities, or financing nuclear fuel cores.

C. Commonwealth Edison Company

1. Commonwealth Edison of Indiana, Inc.

100 percent of the voting common stock is owned by Commonwealth Edison. Commonwealth Edison of Indiana was established in 1932 as an electric utility.

2. Chicago & Illinois Midland Railway Company

100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1936 and is operating as a railway company.

3. Edison Development Company

100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1976 to acquire, develop and manage fuel reserves in the United States.

4. Cotter Corporation

100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1974 for uranium mining and milling in Colorado.

5. <u>Commonwealth Edison Research Corporation</u>
100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1976 for research and development.

6. 100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1978 for insuring casualty risk.

7. <u>Edison Development Canada, Inc.</u>
100 percent of the voting common stock is owned by Commonwealth Edison. The subsidiary was established in 1979 to acquire, develop and manage fuel reserves in Canada.

ME -- All existing subsidiaries were established prior to the commission's approval authority.

NH -- <u>Project Management - Engineering - Consulting Services</u>: UNITIL, Inc.
<u>Customer Billing - Collection Services</u>: UNITIL, Inc.

NM -- <u>Fuel Exploration and Development</u>: PNM (Sunbelt Mining Co)
<u>Real Estate</u>: PNM (Meadows Resources, Inc.); EPE (Franklin Land and Resources Inc.
<u>Other</u>: PNM (Meadow Resources, Inc)--fiberboard plant; PNM (Sunbelt Mining Co.)--gravel hauling and financing of properties; PNM (Paragon Resource)--utility related projects.

Detailed information follows.*

<u>PNM</u>	Meadows Resources, Inc.	$ 89,238,552
	Sunbelt Mining Co.	17,300,000
	Paragon Resources	8,354,014
	Total	$114,892,566
	Percentage of total assets	6.3%
	Percentage of common equity	19.5%
<u>EPE</u>	Franklin Land & Resources	$ 1,491,431
	Percentage of total assets	.2%
	Percentage of common equity	.5%

*diversification totals as of 12/82
equity and asset totals as of 12/81

PNM DIVERSIFICATION SUMMARY

1. <u>Meadows Resources, Inc.</u>

- incorporated 10/1/81
- 100 percent owned by PNM
- PNM's equity investment $89,238,552
- has its own debt, without recourse to PNM
- business: nonutility related investments
- joint ventures:

    a. <u>Bellamah Community Development</u>

    - incorporated 10/1/81
    - partnership with Bellamah Holding Co.
    - 50 percent Meadows, 50 percent Bellamah
    - business: real estate

    b. <u>Montana de Fibra</u>

    - incorporated 5/14/82
    - partnership with Frontier Fiber, Inc.
    - 95 percent Meadows, 5 percent Frontier Fiber
    - business: owns & operates medium-density fiberboard plant

2. <u>Sunbelt Mining Co.</u>

- incorporated 12/13/79
- 100 percent owned by PNM
- PNM's equity investment $17,300,000
- has its own debt and partnership agreements without recourse to PNM
- business: coal mining, gravel hauling
- joint venture

    a. <u>La Plata Partnership</u>

    - incorporated 11/24/81
    - no assets
    - business: financing vehicle for La Plata properties

3. <u>Paragon Resources</u>

- incorporated 7/25/72 a Public Service Land Co.
- 100 percent owned by PNM
- PNM's equity investment $8,354,014
- business: utility related projects

EPE DIVERSIFICATION SUMMARY

Franklin Land & Resources, Inc.

- incorporated 9/12/77
- 100 percent owned by EPE
- EPE's total equity investment $1,491,431
- EPE does not guarantee liabilities
- business: leases real property to EPE for offices, parking, storage, etc.

a. ZIMWALL, Inc.

- incorporated 4/27/82
- 100 percent owned by Franklin Land & Resources
- total equity investment $60
- has not commenced operation

NY -- Fuel Exploration and Development

Niagara Mohawk - NM Uranium
$20 million Investment, "0" Earnings

Foreign Finance Subsidiaries

Niagara Mohawk - Niagara Mohawk Finance N.V.
$17,352,817 Investment, $2,920,900 Earnings

New York State Electric & Gas - NYSEG Finance N.V.
$12,000 Investment, "0" Earnings

Long Island Lighting Co. - LILCO International N.V.
$12,000 Investment, "0" Earnings

Short Line Railway

New York State Electric & Gas - Somerset Railroad Corp.
$200,000 Investment, "0" Earnings

Economic Development

O & R Utilities - one or more subsidiaries
$5,000,000 Investment (recently authorized)

OR -- Fuel Exploration and Development: Portland General Electric, Pacific Power & Light
Real Estate: Portland General Electric
Energy Conservation Services: Portland General Electric
Fuel Transportation - Transloading: Pacific Power & Light

Project Management - Engineering - Consulting Services: Portland General Electric, Pacific Power & Light
Energy Education Services: Portland General Electric, Pacific Power & Light
Equipment Wholesaling: Pacific Power & Light

UT -- Cogeneration: Utah Power & Light Company (Energy National)--An investment of $416,000 made on 12/31/84

AL, AZ, AR, CA, CO, CT DE, DC, FL, GA, HI, ID, KS, KY, LA, MA, MI, MN, MS, MO, MT, NV, NJ, NC, ND, OH, PA, SC, SD, TN, TX, WA, WV -- No answer or not applicable.

5. Are there any electric utility subsidiaries or affiliates, which your commission is aware of, that are not under its authority? If so, how many exist in each of the following fields of business? For each business type, please list the name of each electric utility involved and the number of subsidiaries and affiliates that it has.

AL -- Fuel Exploration and Development: Alabama Power Company - 1
Real Estate: Alabama Power Company (same subsidiary as recreation and timber)
Appliance Sales - Leasing - Service: Removed from Alabama Power retail jurisdiction by a cost of service study
Timber Harvesting: Alabama Power Company
Recreation Area-Marina: Alabama Power Company

AZ -- Note: All subsidiaries and affiliates listed below are wholly owned by the parent company.

Fuel Exploration and Development: Arizona Public Service: Malapai Resources Company, APS Fuel Company; Citizens Utilities Company: Citizens Resources Company; Tucson Electric Power: Rincon Resources, Inc.
Real Estate: APS: Energy Development Company
Energy Conservation Services: CP National: CP National Energy Management Services, Inc.
District Heating: APS: Energy Development Company
Appliance Sales-Leasing-Service: APS: Energy Development Company: CPN: CP National Leasing Company, CP National Terminal Equipment Co.

Project Management-Engineering-Consulting Services: CPN: The Warner-Whitney Group, Inc., RAI Consultants, Inc.
Computer Software Sales: CPN: The Communications Processing Group, Inc.
Solar-Renewable Product Sales: CPN: Trident Energy Systems, Inc.
Water Rights - Storage: Citizens has water rights and storage via its distribution systems.
Water Sales - Distribution: Citizens has many water companies both in an out of the state of Arizona. The ones in-state all fall within the jurisdiction of the ACC.
Commercial Paper Sales: APS: APS Finance Company, Netherland Antilles; TEP: Rincon Securities, Inc.
Telephone-Telecommunications: Citizens has companies outside the State of Arizona not within ACC jurisdiction; CPN: CP National Telephone Service Co, Tel-Logic Communications, Inc., RAI Consultants, Inc., Network Services Co.
Other (Please specify): (1) TEP is spinning off its generation facilities; currently, Alamito Company and Valencia Energy Company are wholly owned susidiaries that generate power; Rincon Investing Co invests funds; (2) APS: El Dorado Investment Co.; (3) Citizens Southwestern Investments, Inc.; (4) CPN: Denro Laboratories, Inc. (manufactures air traffic control equip.) CP National Construction Co., CP National Transportation Co. (Air Travel).

AR -- Fuel Exploration and Development: Arkansas Power & Light Company affiliate: System Fuels, Inc.
Fuel Transportation-Transloading: Arkansas Power & Light Company affiliate: System Fuels, Inc.
Cogeneration: Arkansas Power & Light Company's affiliate: Electric, Inc.
Project Management-Engineering-Consulting Services: Arkansas Power & Light Company's affiliate: Middle South Services, Inc.; South West Power Company's affiliate: Central & South West Services, Inc.
Other (Please specify): Nucleus Power Plant Ownership - Arkansas Power & Light Company's affiliate: Middle South Energy, Inc.

CA -- Fuel Exploration and Development: Pacific Gas & Electric - 4: Natural Gas Corporation of California, NGC Production Company (a wholly-owned subsidiary of Natural Gas Corporation of California), Pacific Transmission Supply Company (a wholly-owned subsidiary of Pacific Gas Transmission Company), and PG&E Gas Supply Company (a wholly-owned subsidiary of PG&E); Southern California Edison - 3: Bear Creek Uranium Company--mining of and milling of uranium ore (Mono Power Company owns 50 percent interest in this partnership), Mono Power Company--the acquisition and development of mineral properties and interest therein, Polo Verde Uranium Venture--primarily the acquisition and disposition of uranium properties and interests therein (Mono Green Mountain Company owns 15.8% interest in this partnership); San Diego Gas & Electric Co.--geothermal exploration and development and coal leases.

Real Estate: Pacific Gas & Electric Company: JWP Land Company (a wholly-owned subsidiary); Southern California Edison Company - 3: Associated Southern Investment Company--primarily real property interests, Calabasas Park Company--primarily the development, operation, and management of real property and improvements (a partnership--Associated Southern Investment Company owns 79% interest), Southern Surplus Realty Company--primarily the acquisition, holding, and disposition of real property, particularly the homes of employees transferred to new geographical locations.
Energy Conservation Services: Pacific Gas and Electric Co: Pacific Construction Services Company--finances loans to PG&E residential customers for the installation of conservation and weatherization measures under a zero interest conservation financing program (a wholly-owned subsidiary of PG&E); Southern California Edison Company: Construction Financing Corp.--primarily the execution of the mandated residential conservation financings.
Cogeneration: Southern California Edison Co.: Southern Sierra Energy Co.--primarily the production of electricity and steam for the purpose of enhancing oil recovery.
Commercial Paper Sales: Pacific Gas and Electric Co.: Pacific Gas and Electric Finance Company, N.V.--a Netherlands Antilles corporation, primarily borrows funds outside the United States and lends such funds to PG&E and its subsidiaries (a wholly-owned subsidiaries of PG&E); Southern California Edison Co: Southern California Edison Finance Company, N.V.--a Netherlands Antilles corporation engaged primarily in financing activities of Southern California Edison and its affiliates
Telephone-Telecommunications: Southern California Edison Co.: primarily the development, operation, and maintenance of a community antenna television system (a partnership of which Associated Southern Investment Co. own 79 percent interest).
Other (Please specify): Pacific Gas and Electric Co. - 2: ANGUS Chemical Company--a specialty chemical company which produces and markets nitroparaffin and its derivatives (Pacific Gas Transmission Company owns 42.16 percent and Alberta Natural Gas Company LTD. owns 55.88 percent), ANGUS Petrotech Corporation--engaged in the enhanced recovery of oil from semi-depleted oil fields (Pacific Gas Transmission Company owns 80 percent and Alberta Natural Gas Company owns 20 percent); Southern California Edison Company: Energy Services Inc.--primarily furnishing energy services to commercial customers.

The Pacific Gas and Electric Company also has numerous gas related subsidiaries and affiliates. A detailed description of these subsidiaries and affiliates is given below.

- Alberta Natural Gas Company Ltd owns and operates a natural gas pipeline in British Columbia and extraction facilities in Alberta.

ANG transports gas for Alberta and Southern Gas Co. Ltd. from Alberta, Canada, to the international border near Kingsgate, British Columbia (B.C.). ANG is a 49.99 percent owned affiliate of Pacific Gas Transmission Company. ANG owns 55.88 percent of ANGUS Chemical Company, which produces and markets nitroparaffins and its derivatives and 20 percent of Angus Petrotech Corporation.

- Alberta and Southern Gas Co. Ltd purchases gas in Alberta, Canada, most of which is sold to Pacific Gas Transmission Company at the international border near Kingsgate, B.C. PG&E and its affiliates own 100 percent of the voting stock of Alberta and Southern Gas Co. Ltd.

- Pacific Gas Transmission Company owns and operates a natural gas pipeline in the states of Idaho, Washington, and Oregon. The Company purchases natural gas from Alberta and Southern Gas Co. Ltd at the international border near Kingsgate, B.C. and transports it for sale to PG&E at the California border. PGT also owns a 49.99 percent interest in Alberta Natural Gas Company Ltd which operates a natural gas pipeline and extraction facilities in Canada. Additionally, PGT has interests in oil and gas leasehold acreage in the Rocky Mountain area through its wholly-owned subsidiary Pacific Transmission Supply Company. PGT's wholly-owned subsidiary, Rocky Mountain Gas Transmission Company, will participate in the construction and operation of a proposed natural gas pipeline from the Rocky Mountain area to the California border. PGT also owns 42.16 percent of ANGUS Chemical Company, and 80 percent of Angus Petrotech Corporation. PG&E owns 50.17 percent of the voting stock of PGT.

- PG&E and its subsidiaries are equal participants with Pacific Lighting Corporation (PLC) and its subsidiaries in two projects which involve the construction of facilities to import liquified natural gas (LNG) from Alaska and Indonesia. Both projects would use a proposed regasification terminal near Point Conception, California. PG&E's project interests are held in the following four subsidiaries:
    * Alaska California LNG Company (partner in Pacific Alaska LNG Associates)
    * Pacific Gas LNG Terminal Company (partner in Western LNG Terminal Associates)
    * Pacific Gas Marine Company (partner in Pacific Marine Associates)
    * Pacific Indonesia LNG Company (50 percent owned by PG&E)

  Based on present market conditions, natural gas supplies are considered adequate to meet demand currently and in the near future. Therefore, the Company and PLC have elected to defer completion of the project facilities. In late 1982, the Company filed an application with the CPUC seeking authorization to include in rate base as "plant held for future use" the costs associated with its participation in the Alaska and Indonesia LNG projects. Given the current status of the projects the activities of the Company's four subsidiaries are limited.

- Calaska Energy Company is a partner in the Alaska Northwest Natural Gas Transportation Company (ANNGTC). ANNGTC has been selected to build the Alaskan section of the Alaskan Highway Pipeline Project. When a workable financing plan is developed, this project will construct and operate a pipeline transmission system to bring natural gas from Prudhoe Bay on the northern slope of Alaska through Canada to western, midwestern, and eastern markets in the lower 48 states. Calaska Energy is a wholly-owned subsidiary of PG&E.

- Gas Lines, Inc., transports natural gas for various customers through the PG&E system. Gas Lines, Inc., is a wholly-owned subsidiary.

- Rocky Mountain Gas Transmission Company will be a partner in Rocky Mountain Pipeline Company. Subject to regulatory approval and favorable gas market conditions, Rocky Mountain Pipeline Company proposes to construct, own, and operate a pipeline extending from Wyoming to the Nevada-California border. RMGT is a wholly-owned subsidiary of PGT.

- Standard Pacific Gas Line, Inc., maintains pipelines and transports natural gas for PG&E and Chevron, U.S.A., Inc. PG&E owns 85.71 percent of the voting stock of Standard Pacific Gas Line, Inc.; the remainder is owned by Chevron, U.S.A., Inc.

CO -- Fuel Exploration and Development: Public Service Company of Colorado: Fuel Resources Development Company
Real Estate: Public Service Company of Colorado: Ba(sic?) Corporation and 1480 Welton, Inc.

CT -- Real Estate: 2

DE -- Fuel Exploration and Development: Delmarva Energy Company - Natural Gas Exploration
Other (Please specify): Delmarva Industries, Inc. - Alternative Energy Resources

DC -- Load Management Controls: Pepco Interprises, Inc. is a wholly-owned subsidiary of Potomac Electric Power Company (net income is immaterial and the investment is $200,000)
Other (Please specify): Investment-leveraged base and preferred stock. Potomac Capital Investment Inc. is a wholly-owned subsidiary of Potomac Electric Company (net income is 4 percent of the consolidated income and the investment is $56 million).

FL -- Fuel Exploration and Development:
Utility - Florida Power Corporation (FPC): Affiliate - Electric Fuels Corporation (EFC). FPC and EFC are under the same holding

company, Florida Progress Corporation. The wholly owned subsidiary of EFC that is in fuel exploration and development is Alternative Fuels Corporation (AFC). A wholly owned subsidiary of AFC, COMCO of America, Inc., is currently producing and selling under contract a coal-oil mixture for generation to Florida Power Corporation.
Utility - Tampa Electric Company (TECO): Affiliate - TECO Coal Corporation. Utility and affiliate are under the same holding company, TECO Energy, Inc.
Utility - Florida Power & Light Company (FPL): Affiliate - Fuel Supply Service, Inc. The utility and affiliate are under the same holding company, FPL Group, Inc. This affiliate is involved in fuel exploration and proprietary fuel research and development projects.

Real Estate:
Utility - Florida Power Corporation (FPC): Affiliate - Talquin Corporation. The FPC and Talquin Corporation are under the same holding company, Florida Progress Corporation. Talquin Corporation is presently investing in real estate and income producing property for future development.
Utility - Tampa Electric Company (TECO): Affiliate - Tampa Bay Industrial Corporation. The utility and affiliate are under the same holding company, TECO Energy, Inc. Tampa Bay Industrial Corporation is esentially in real estate management of an office building, parking lot, etc.
Utility - Florida Power & Light Company (FPL): (a) wholly owned subsidiary - Land Resources Investment Company. This subsidiary holds real property used or to be used by the electric utility in its utility operations, and (b) Affiliate - W. Flagler Investment Corporation. Utility and affiliate are under the same holding company, FPL Group, Inc. The affiliate is engaged in general real estate investment and development and agricultural operations.

Fuel Transportation - Transloading:
Utility - Florida Power Corporation: (a) Affiliate - Electric Fuels Corporation. The utility and affiliate are under the same holding company, Florida Progress Corporation, and (b) wholly-owned subsidiary of EFC, Mississippi River Terminals, Inc. is a 33 1/3 percent partner in International Marine Terminals, a transloading and storage facility. Coal purchased by EFC for sale to the utility is transloaded or stored at this facility. EFC also has a 65 percent partnership interest in Dixie Fuels, Limited. This partnership provides Gulf transportation services for coal shipments from the transloading facility, International Marine Terminals, to the utility's plant site.

Utility - Tampa Electric Company (TECO): (a) Affiliate - TECO Transport & Trade Cororation. Utility and affiliate are under the same holding company, TECO Energy, Inc., (b) wholly-owned subsidiary of affiliate - Electro-Coal Transfer Corporation (ECT). This company provides transloading and storage facilities for coal being shipped to the utility's plants, (c) wholly-owned subsidiary of ECT - G.C. Service Company, Inc. G.C. Service provides coal unloading services at Tampa Bay, (d) wholly-owned subsidiary of affiliate - Gulfcoast Transit Company. This company provides ocean barge transportation services for coal shipped from the transfer facility to the utility's plant, (e) wholly-owned subsidiary of affiliate - Mid South Towing Company. This company provides river barge transportation services for utility-purchased coal being shipped to the transfer facility, and (f) wholly-owned subsidiary of affiliate - Southern Marine Management Company. This company provides management expertise and accounting services to the other subsidiaries of TECO Transport and Trade Corporation.

Appliance Sales - Leasing Service:
Utility - Gulf Power Company (GPC). Gulf Power Company owns an appliance sales and service division. However, it is not set up as a separate entity. Revenues and expenses and investment associated with this service are excluded for ratemaking purposes and are not regulated by this Commission.

Computer Software Sales:
Utility - Florida Power Corporation (FPC): Affiliate - Better Business Systems, Inc. The utility and affiliate are under the same holding company, Florida Progress Corporation. The affiliate manufactures and markets business forms and systems and computer related accessories.

Other - Mining:
Utility - Florida Power Corporation (FPC): (a) Affiliate - Electric Fuels Corporation (EFC). The utility and affiliate are under the same holding company, Florida Progress Corporation, (b) wholly-owned subsidiary of EFC, Homeland Coal Company, Inc. Homeland Coal Company has a 50% partnership interest in Powell Mountain Joint Venture, which mines and sells coal to EFC, (c) wholly-owned subsidiary of EFC, Little Black Mountain Land Company, which owns coal reserves, (d) wholly-owned subsidiary of EFC, Little Black Mountain Coal Reserves, which has an 80 percent partnership in Dulcimer Land Company. Dulcimer leases coal reserves from Little Black Mountain Land Company and then sub-leases the reserves to Powell Mountain Joint Venture. EFC also has a 50 percent partnership interest in Coal Field Leasing Joint venture which owns mining equipment and leases it to Powell Mountain Joint Venture.
Utility - Tampa Electric Company (TECO): (a) Affiliate - TECO Coal Company. The utility and affiliate are under the same holding company, and (b) wholly-owned subsidiary of TECO Coal - Gatliff Coal Company. Gatliff mines coal for sale to the utility.
Other - Export Sales
Utility - Florida Power Corporation (FPC): (a) Affiliate - Electric Fuels Corporation (EFC). Utility and affiliate are under the same holding company, Florida Progress Corporation, and (b) wholly-owned subsidiary of EFC - EFC Trading, Inc. This company is

relatively new and will be involved in export sales of coal and other fuels.

Other - Leasing:

Utility - Florida Power Corporation (FPC): Affiliate - Progress Financial Services Incorporated. Utility and affiliate under the same holding company, Financial Services Incorporated. Affiliate is involved in equipment leasing.

Other - Investments:

Utility - Florida Power Corporation: Affiliate - Progress Equities Incorporated. The utility and affiliate are under the same holding company, Florida Progress Corporation. Affiliate is involved in equity investments in unrelated companies.

Utility - Tampa Electric Company (TECO): Affiliate TECO Energy Finance. The utility and affiliate are under the same holding company, TECO Energy, Inc. TECO Energy Finance was created to invest in the Euro-Bond Markets. The investments were not made and the company is presently inactive.

Other - Electric Utilities:

Utility - Gulf Power Company (GPC): Affiliates - Alabama Power Company, Georgia Power Company, and Mississippi Power Company. GPC and affiliates are under the same holding company, The Southern Company. The affiliates are independent electric generating utilities.

Other - Service Company:

Utility -Gulf Power Company (GPC): Affiliate - Southern Company Service, Inc. (SCS). GPC and affiliate are under the same holding company, The Southern Company. SCS provides GPC with a variety of services such as customer billing, consulting, engineering and fuel contract evaluation and administration.

Other - Consulting:

Utility - Gulf Power Company (GPC): Affiliate - Southern Electric International, Inc. GPC and affiliates are under the same holding company, The Southern Company.

Detailed corporate organization charts of TECO Energy, Inc. and the Florida Progress Corporation are shown in figures A-1 and A-2, which follow.

Fuel Exploration and Development: Idaho Power Company - one coal mining subsidiary, and Washington Water Power Company - one coal mining subsidiary

Cogeneration: Utah Power & Light Company - one cogeneration subsidiary

Computer Software Sales: Washington Water Power Company - one subsidiary markets both hardware and software for on-site billing of utility customers

Customer Billing - Collection Services: same as above

Timber Harvesting: Washington Water Power Co. - one coal mining subsidiary harvests timber from coal properties

Telephone - Telecommunications: Pacific Power & Light Co. The parent holding company also owns the telephone company.

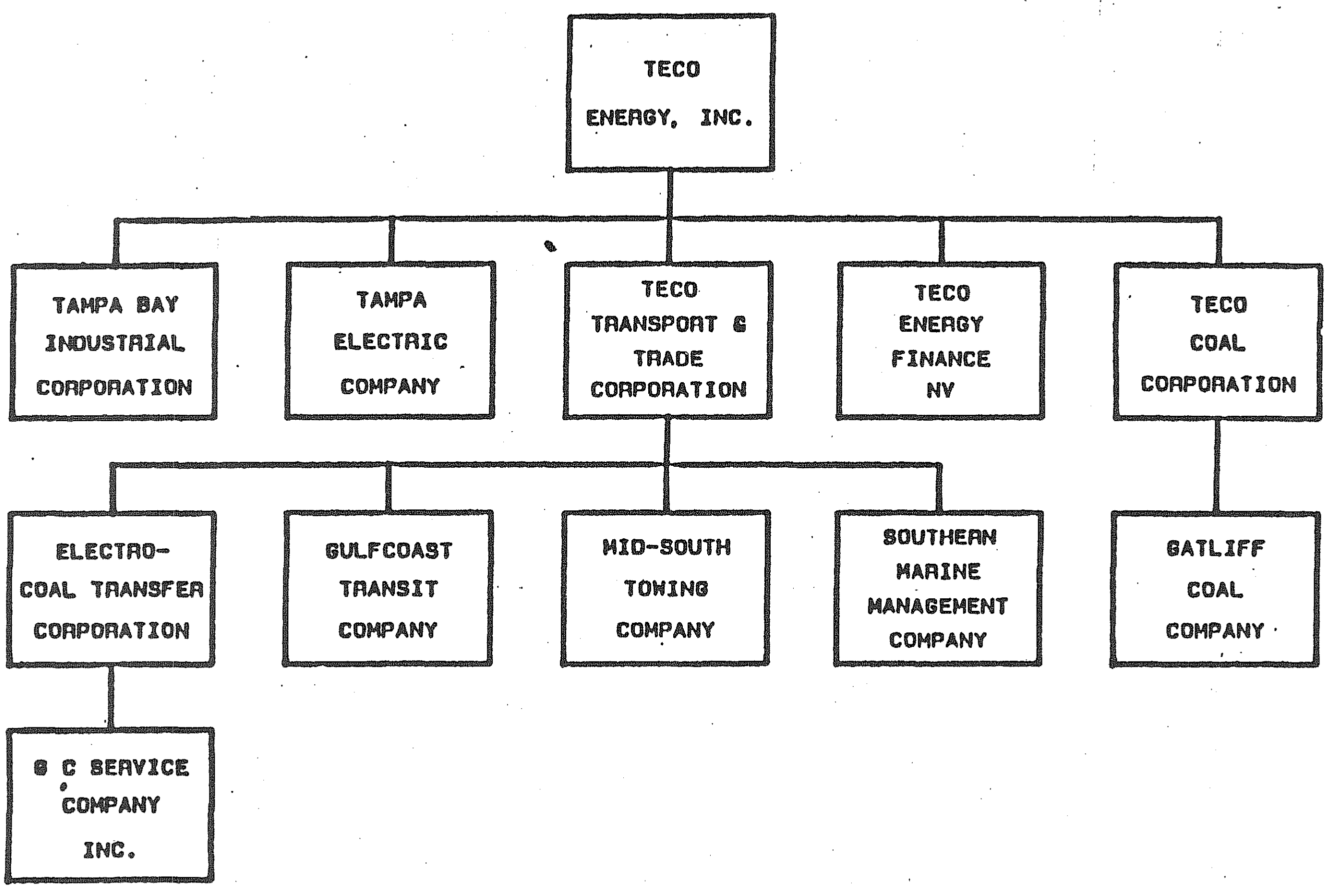

Figure A-1 Teco energy corporate chart

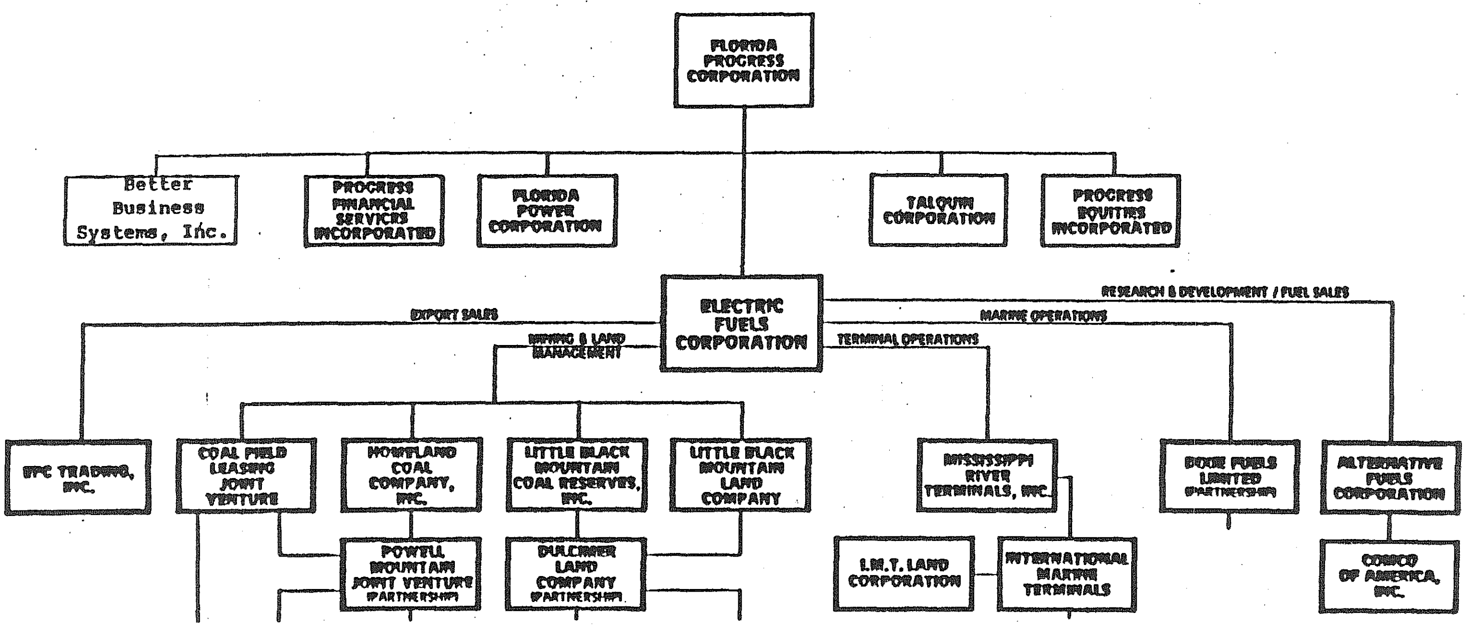

Figure A-2   Florida progress corporate chart

IL -- Other (Please specify): Illinois Power - one subsidiary established to aid in a merger proposal.

The following electric utilities in Illinois have Commission approval for subsidiaries or affiliates.

- Central Illinois Light Company (CILCO): In December, 1984 the Illinois Commerce Commission approved the formation of a holding company of which CILCO will be a 100 percent owned subsidiary of the holding company. Details of the types of business are not yet available.

- Illinois Power Company (I.P., Inc.): 100 percent of the voting common stock is owned by Illinois Power. The subsidiary was incorporated in October, 1981 to aid in the consummation of the merger with Mt. Carmel Public Utility Company.

KS -- Fuel Exploration and Development: Sunflower Electric Cooperative Subsidiary - Natural Gas Sales Co.

KY -- Real Estate: American Electric Power-1

ME -- Other (Please specify): Hydroelectric: Central Maine Power - Union Water Power; Maine Public Service - Maine/New Brunswick Electric Company.

MI -- Fuel Exploration and Development: Consumers Power Co.-1; Michigan Gas Utilities Company-1
Real Estate: Michigan Consolidated Gas Company-1
Fuel Transportation-Transloading: Detroit Edision-1
Project Management-Engineering-Consulting Services: Detroit Edison-1
Computer Software Sales: Detroit Edison-1
Customer Billing-Collection Services: Consumers Power-1

Further information on corporations controlled by Michigan utilities is below.

Michigan Power Company controls the Michigan Gas Exploration Company, which is engaged in the business of exploring and drilling for natural gas and/or oil in certain areas of Southwestern Michigan. Michigan Power Company owns 100 percent of the voting stock. The business is currently inactive.

The Detroit Edison Company controls several subsidiaries, including The Edison Illuminating Company of Detroit (real estate), the Washtenaw Energy Corporation (fuel procurement), the Midwest Energy Resources Company (fuel procurement), the St. Clair Energy Corporation (fuel procurement), and United Technical Service, Inc. (professional consulting services/products). Each of these subsidiaries has 100 percent of its voting stock owned by the Detroit Edison Company.

The Indiana & Michigan Electric Company has two wholly-owned coal companies as subsidiaries. They are the Price River Coal Company, Inc. and the Blackhawk Coal Company, Inc.

The Wisconsin Public Service Company owns five subsidiaries. Two of the wholly-owned subsidiaries, the Wisconsin Public Services Resources, Inc. and Delores Bench Resources Limited, are now inactive. A third subsidiary, the Delores Bench General Partner was created to act as the general partner in the now inactive Delores Bench Resources Limited. Two of the subsidiaries are inactive. The Wisconsin River Power Company, a joint venture with the Wisconsin Power & Light and the Consolidated Water Power Companies, produces and sells energy through ownership and operation of two hydroelectric plants. The Wisconsin Public Service Corporation owns 33.12 percent of its voting stocks. The other active subsidiary is the Wisconsin Valley Improvement Company, which operates a system of dams and water reservoirs on the Wisconsin River and its tributaries. It generates no electricity. Wisconsin Public Service owns 26.94 percent of its voting stock.

Wisconsin Electric Power Company owns five wholly-owned affiliates or subsidiaries, two of which are active and three of which are inactive. The active subsidiaries are the Wisconsin Natural Gas Company, a gas utility, and the Badger Service Company, a coal land development company. The inactive subsidiaries are the Wisconsin Michigan Power Co., Inc., the Wisconsin Energy Corporation, and WEPCO Acquisition, Inc.

The Upper Peninsula Power Company has one subsidiary, the Upper Peninsula Generating Company. This subsidiary is jointly-owned by Cliff Electric Service Company (a wholly-owned subsidiary of The Cleveland-Cliffs Iron Company) and The Upper Peninsula Power Company. The Upper Peninsula Generating Company is engaged in the business of generating, transmitting, and selling electricity. Cliffs Electric Service Company owns 93 percent and Upper Peninsula Power Company owns 7 percent of the voting stock.

The Consumers Power Company owns several subsidiaries, all of which are wholly-owned and are held either directly or indirectly through another wholly-owned subsidiary. The directly-held, wholly-owned subsidiaries are the Michigan Gas Storage Company, the Northern Michigan Exploration Company, the Michigan Utility Collection Service Co., Inc., Plateau Resources Limited, Utility Systems, Inc., Conar Corporation, and Consumers Power Finance, NV. The three wholly-owned subsidiaries that are indirectly-held are Canyon Homesteads, Inc., which is a wholly-owned subsidiary of Plateau Resources Limited, and NOMECO Latin America, Inc. and NOMECO Australia PTY Limited, which are wholly-owned subsidiaries of Northern Michigan Exploration Company.

The Michigan Gas Storage Company is engaged in the purchase of gas from an interstate pipeline supplier, transmission and storage of the gas, and the sale of gas to Consumers Power Company.

The Northern Michigan Exploration Company and its wholly-owned subsidiaries NOMECO Latin America Inc. and NOMECO Australia PTY Limited are engaged in the exploration for and the development, purchase, and sale of oil and natural gas. The two wholly-owned subsidiaries also deal in oil and gas interests and rights.

The Michigan Utility Collection Service Company, Inc. is engaged in collection services for past due utility bills.

Plateau Resources Limited is engaged in the exploration for and the development, purchase, and sale of uranium. Its wholly-owned subsidiary, Canyon Homesteads, Inc. develops housing facilities for mine and mill workers of Plateau Resources Limited.

Utility Systems, Inc. is engaged in the receipt, preservation, and dissemination of information relating to construction or other activities which may affect utility services in Michigan.

Conar Corporation supports research and development in promising new applications in energy.

Consumers Power Finance, NV was organized to obtain financing from sources outside the United States to support the activities of Consumers Power Corporation and its subsidiaries; however, as of December 31, 1983, it had not yet commenced operations.

MN -- District Heating: Northern States Power Company (sale of steam to an industrial customer)

MO -- Real Estate: Missouri Public Service Company - 1:

NV -- Fuel Exploration and Development: Sierra Pacific Resources (80 percent utility-owned). Has 1 fuel exploration subsidiariy.
Real Estate: Sierra Pacific Resources (80 percent utility-owned). Has 1 land development company subsidiary.
Water Rights-Storage: Sierra Pacific Resources (80 percent utility-owned). Has a water subsidiary that obtains water rights and stores water for distribution in the Reno area.
Water Sales-Distribution: Sierra Pacific Resources (80 percent utility-owned). Has a subsidiary that distributes water in the Reno area.
Other (Please specify): Sierra Pacific Resources (80 percent utility-owned). Has a gas distribution subsidiary that distributes gas in the Reno area only.

NH -- Real Estate: Public Service of New Hampshire

NJ -- Fuel Exploration and Development: P.S.E.&G.: P.S.E. Gas Research Corporation, Energy Development Corporation; J.C.P.&L.: Saxton Nuclear Experimental Corporation
Real Estate: A.C.E.: Atlantic Housing, Inc.
Fuel Transportation-Transloading: P.S.E.&G.: Energy Pipeline Corp., Gasdel Pipeline System
Cogeneration: A.C.E.: Deepwater Operating Company

Other (Please specify): P.S.E.&G.: P.S.E.&G. Overseas Finance N.V. --aids in financing activities with foreign investors, Mulberry Street Urban Renewal Corporation (MSURC) owns and operates facility used for records storage by PSE&G and attached parking facilities used by PSE&G and by another lessee for public parking.

NY -- Cogeneration: Niagara Mohawk - HYDRO - CO., $515,295 investment, ($573,303) loss; Orange & Rockland - O & R Energy Development, $11,897,277 investment, $102,302 Earnings
Energy Conservation Services: Long Island Lighting Company - LILCO Energy Systems, $111,197 investment, ($489) loss; Central Hudson Gas & Electric - Central Hudson Enterprises, $230,000 investment, ($7,437) loss.
Real Estate: In most cases the subsidiaries were initially established by the utility as a means of obtaining land without the seller knowing that a "utility" was interested in the property. Rochester Gas & Electric - Roxdel Corp., $2,237,100 investment, "0" earnings; Central Hudson Gas & Electric - Phoenix Development Co., $35,867 investment, ($1,002) loss; Central Hudson Gas & Electric - Green Point Development, $160,000 investment, $73,409 earnings; O & R Utilities - Clove Development Corporation, $1,649,747 investment, $162,947 earnings; Long Island Lighting - Marquez Development, $26,898 investment, $1,518 earnings; Consolidated Edison - Davids Island Development, $4,864,681 investment, "0" earnings.

ND -- Fuel Exploration and Development: Montana-Dakota Utilities Co. - 3: Knife River Coal Mining Co., Fidelity Gas Co., Wibaux Gas Co.

OH -- Fuel Exploration and Development: Ohio Power Company owns (1) Central Ohio Coal Company for surface-mining of coal, (2) the Southern Ohio Coal Company, which operates deep mines, and (3) Windsor Power House Coal Company. The Columbus and Southern Ohio Electric Company owns Simco, Inc., a subsidiary engaged in leasing coal-mining equipment and related mining operation.

Real Estate: Cleveland Electric Illuminating Company owns CEICO Company, a subsidiary which owns nonutility land; Columbus and Southern Ohio Electric Company owns Colomet, Inc., a subsidiary engaged in real estate activities; the Dayton Power and Light Company has a wholly-owned subsidiary that owns the company's headquarters building in downtown Dayton.

Load Management Controls: Cleveland Electric Illuminating Company owns Dynamic Energy Ventures, Inc. (Dyneco), which sells, installs and services uninterruptible power supplies, energy management systems and metering services.

Commercial Paper: The Ohio Edison Company owns an off-shore subsidiary, Ohio Edison Finance N.V., in the Netherlands Antilles, which enables the company to obtain funds thrugh the sale of notes to foreign investors.

Other (Please specify): Cincinnati Gas & Electric Company has several subsidiaries including The Union Light, Heat and Power Company, the Miami Power Corporation, the West Harrison Gas and Electric Company, the Lawrenceburg Gas Company, the Lawrence Gas Transmission Corporation, and the Tri-State Improvement Company and YGK, Inc.; Cleveland Electric Illuminating Company owns CEICO Company, a subsidiary which performs certain submetering services; Cleveland Electric Illuminating Company also owns CCO Company, a subsidiary which coordinates the operation of a five-company power pool called the Central Area Power Coordinating Group. The costs of CCO are shared by all CAPCO companies. The Ohio Edison Company wholly owns the Pennsylvania Power Company, a Pennsylvania subsidiary, which furnishes electric service in 138 communities as well as in rural areas of western Pennsylvania, and which also sells electric energy at wholesale to five municipalities. The Ohio Edison Company has a subsidiary, the Ohio Edison Energy Trust, which was established to make available up to $500 million to finance, in part, the construction of Beaver Valley Unit 2, and the shipping part nuclear plant. The Ohio Power Company has two jointly-owned subsidiaries, the Cardinal Operating Company, which owns the Cardinal Plant, and the Central Operating Company (jointly-owned with Appalachian Power Company) to operate the Philip Sporn Power station.

OR -- No.

PA -- Fuel Exploration and Development: Pennsylvania Power and Light Co. - 7, Philadelphia Electric Company - 1.
Real Estate: Pennsylvania Power and Light Co. - 7, Philadelphia Electric Company - 2.
Fuel Transportation-Transloading: Pennsylvania Power and Light Co. - 1
Other (Please specify): Philadelphia Electric Company has a subsidiary engaged in electric distribution equipment rental, the ownership and operation of a public marine terminal and management consulting services.

SC -- Fuel Exploration and Development: Duke Power Company - 1
Real Estate: Carolina Power & Light Co. - 1; Duke Power Company - 1
Equipment Wholesaling: Duke Power Co. - 1
Commercial Paper Sales: Carolina Power & Light Co. - 1; Duke Power Co. - 1

SD -- Fuel Exploration and Development: 10
Real Estate: 4
Fuel Transportation-Transloading: 2

TX -- Fuel Exploration and Development: Texas Utilities Electric Company - 2: TUMCO (affiliate, TUPCO (affilaite); Houston Lighting and Power Company - 2: Utility Funds, Inc. (affiliate), Primary Fuels Inc. (affiliate)

Real Estate: El Paso Electric Company: Franklin Land and Resources (a wholly owned subsidiary). The company used the equity method of accounting for the subsidiary's profit.

Fuel Transportation-Transloading: The same as fuel exploration and
UT -- development.

WA -- Cogeneration: Texas New Mexico Power Company: Capital Cogeneration (less than a 50 percent equity owner).

None

Fuel Exploration and Development: Pacific Power & Light Company - 27: NERCO, Inc. (wholly-owned, NERCO Mining Company (wholly-owned) Antelope Coal Company (wholly-owned), NERCO Coal Company (wholly-owned), NERCO Oil and Gas, Inc. (wholly-owned), Pacific Creek Coal Company (wholly-owned), Pacific Minerals, Inc. (wholly-owned) Resource Development Co., Inc., (wholly-owned), Spring Creek Coal Company (wholly-owned), Western Minerals, Inc. (wholly owned), Decker Coal Company (joint-venture, 50 percent owned), Bridger Coal Company (joint-venture, 66 2/3 percent owned), Basin Coal Company (inactive, but wholly-owned), Cherokee Coal Company (inactive, but wholly-owned), P-V Mining Company, Inc. (wholly-owned), Sequatchie Valley Coal Corporation (wholly-owned), NEDCO, Inc. (wholly-owned), Tefon Nuclear Exploration (40 percent owned), Clements Energy, Inc. (wholly-owned), Clements Energy Leasing, Inc. (coal lease development, wholly-owned), Montana Royalty Company, Ltd. (coal lease development, limited partnership, 50 percent owned), Bankhead Mining Company, Inc. (wholly-owned), Cobb Coal Company, Inc. (wholly-owned), Sand Mountain Minerals (wholly-owned; Washington Water Power Company - 2: Washington Irrigation & Development Company (wholly-owned), Development Associates (oil and gas, wholly-owned)

Real Estate: Puget Sound Power & Light Company - 1: Puget Western, Inc. (industrial land development, wholly-owned); Pacific Power & Light Company - 2: Westana, Inc. (land development, 50 percent of voting stock owned), STU Partnership (PII headquarters building, 50 percent ownership); The Washington Water Power Company - 2: Spokane Industrial Park, Inc. (purpose of owning and leasing property to manufacturing and other business enterprises, 99 percent owned), The Limestone Company Inc. (92 percent owned)

Fuel Transportation-Transloading: Pacific Power & Light Company - 3: Astoria Coal Terminal Inc. (coal transportation, wholly-owned), NERCO River Terminal Company (coal transportation, wholly-owned)

Cogeneration: Pacific Power & Light Company--NORNEV Demonstration Geothermal Company (geothermal generation, 25 percent ownership); The Washington Water Power Company--WP Energy Co. (to finance and construct a wood-waste-fired generation facility, wholly-owned)

Project Management-Engineering Consulting Services: Pacific Power & Light Company - 1: Associated P&C Engineers, Inc. (engineering, 80 percent ownership); Puget Sound Power & Light Company - 1: Puget Consultants Inc. (energy consulting, wholly-owned)

Customer Billing-Collection Services: The Washington Water Power Company--Water Power Improvement Company (wholly-owned, owns 64 percent of ITRON, Inc., which is engaged in research, development, and leasing of a portable billing system.

Commercial Paper Sales: Puget Sound Power & Light Company - 2: Puget Sound Energy Company (financing, wholly-owned), Puget Construction Co. (financing, wholly-woned); Pacific Power & Light Company--Pacific Power Finance, N.V. (international finance, wholly-owned)

Telephone-Telecommunications: Pacific Power & Light Company - 31: Pacific Telecom, Inc. (a telephone holding company, 93 percent owned), Alascom, Inc. (long-lines telecommunications service, wholly-owned), Audio Group, Inc. (provides background music, wholly-owned), Cascada Autovon Company (telephone utility service, wholly-owned), House of Sound, Inc. (provides background music, wholly-owned), Inter Island Telephone Company, Inc. (telephone utility service, wholly-owned), Music Systems, Inc. (background music, wholly-owned), Pacific Telecom Export Sales Corporation (distribution and sales of telephone equipment--Chilean venture, wholly-owned), Rose Valley Telephone Company (telephone utility service, wholly-owned), Sitka Telephone Company (telephone utility service, wholly-owned), TU International Inc. (international telephone communication investments--a Chilean venture, wholly-owned), TU Service Company (communications supply and warehouse service, wholly-owned), Telephone Utilities of Alaska, Inc. (telephone utility service, wholly-owned), Telephone Utilities of Eastern Oregon, Inc. (telephone utility service, wholly-owned), Telephone Utilities of Oregon, Inc. (telephone utility service, wholly-owned), Telephone Utilities of Washington, Inc. (telephone utility service, wholly-owned), Northwestern Telephone Systems, Inc. (telephone utility service, 99 percent ownership), Gem State Utilities Corporation (telephone utility service, 91 percent ownership), Cable Bus Labs, Inc. (security systems research, 80 percent ownership), Cable Bus Systems Corporation (security systems manufacturing and sales, 80 percent ownership), Tel Com construction (telecommunications and cable television construction, 80 percent ownership), Cid Communications Limita (Chilean mobile telephone service, 50 percent ownership), Multivisions, Ltd. (cable television service, 40 percent ownership), Multivision, Inc. (cable television service, 15 percent ownership), Business Music Company (provides background music, wholly-owned), BMI-HSI, Inc. (provides background music, wholly-owned), Datatel, Inc. (telephone equipment sales, installation and service, wholly-owned), Background Music, Inc. (provides background music, wholly-owned), Business Telephone Systems, Inc. (telephone equipment sales, installation and service, wholly-owned), Pascom (supplies and services business communications systems), owned through Pacific Telecom), Comdial Corporation (produces conventional and decorator phones, 39 percent ownership through Pacific Telecom)

Other (Please specify): The Northwest Energy Services Co. (construction of nuclear and fossil fuel generating plants, jointly controlled with 25 percent ownership each by Puget Sound Power & Light Company, Pacific Power & Light Company, Portland General Electric, and Washington Water Power Company); Pacific Power & Light Company - 17 Pacific Relocation Service Company (employee relocation, wholly-owned), PACOM, Inc. (stock investment, wholly-owned), Williamette Development Corporation (property and stock investment, wholly-owned), Wyopac Services, Inc. (equipment leasing, wholly-owned), Pacific Northwest Power Company (an inactive company organized to develop hydro power in the Northwest, 25 percent ownership), NERCO Minerals Company (minerals development, wholly-owned), Northern Erectors Company (equipment construction, wholly-owned), Alabama Fuels, Inc. (stock investment, wholly- owned), Southern Fuels Inc. (stock investment, wholly-owned), AKRG (mineral exploration, wholly-owned), IBEX Mining Company (mineral development, wholly-owned), Northern Leasing Company Inc. (equipment leasing, wholly-owned), Systronics, Inc. (computer time-sharing, 92 percent ownership), PACE Group, Inc. (inactive, wholly-owned), Pacific American Communications & Energy Group, Inc. (inactive, wholly-owned), Flight Dynamics (holographic overhead display systems for commerical airline, 36 percent ownership through Pacific Telecom), EyeDentify, Inc. (a computer- based identification system which scans and registers the unique blood vessel patterns on the retina of the human eye, 20 percent ownership interest through Pacific Telecom), Washington Water Power Company--Empire Energy Company (nonoperating, wholly-owned)

WV -- Fuel Exploration and Development: Old Dominion (formerly VEPCO)--Laurel Run Mining Company (sells coal to VEPCO, a subsidiary of Old Dominion).

Other (Please specify): (1) Generation - Allegheny Power System owns 40 percent of Bath County Pump Storage facility (VEPCO owns 60 percent) by an affiliate - Allegheny Generating Company. AGC is owned in part by Monongahela Power Company, Potomac Edison Company and West Penn Power. Bath County is not yet in service; (2) Allegheny Power Service Corporation provides general services to Allegheny Power System and subsidiaries, including Monongahela Power Company and Potomac Edison Company; (3) American Electric Power Service Corporation provides general services to AEP and subsidiaries, including Appalachian Power Company and Wheeling Electric Company.

GA, HI, LA, MA, MS, MT, NM, NC, TN, TX--No answer or not applicable.

6. When considering whether to allow an electric utility to set up a subsidiary or affiliate, how does your commission assess any potential risk to the ratepayers of the proposed expansion? What type of risk is examined?

HI -- Most ventures would be in the non-regulated sector and the exposure of liabilities and the allocation of expenses would be most critical. The risk factors would be primarily in the financial aspects.

ID -- No authority.

IL -- The Commission uses the hearing process to assess the potential risk of allowing an electric utility to set up a subsidiary or affiliate.

Proper insulation of utility operations from nonutility businesses is the major type of risk examined. Proper insulation occurs by eliminating cross subsidization, developing methodologies for cost allocations and setting transfer prices and maintaining separate capital structures.

ME -- Downside risk is examined. This is usually not a problem if the subsidiary is a QF with a contract to sell energy.

MA -- If a subsidiary is formed or allowed to be formed the Commission would be mostly concerned with the adverse effect on ratepayers; this includes any request.

MI -- Yes. The commission considers the following query: will this subsidiary, if it fails, endanger the continuation of safe, adequate and reliable electric/energy service to its customers?

NH -- The hearing process identifies and evaluates potential risks to ratepayers. The type of risks include the likelihood of success of the venture, the relative benefits to the customer, and the costs to the customer.

NY -- The Commission examines the risk to ratepayers on a case-by-case basis. It examines the extent of financing being provided by the regulated electric utility and makes a determination that this exposure will not be harmful to the ratepayers. The Commission is concerned about the risk of cross-subsidization and has instituted, and is still instituting safeguards to help ensure that cross-subsidization will not take place.

OR -- No specific risk assessment is made. For utilities that become extensively diversified, "we" set cost-of-equity based upon the risk of "pure" electric utilities. For example, PP&L's equity is determined by looking at Idaho Power, Portland General, and several other "pure" electric utilities.

UT -- The commission has no set procedure to assess any potential risk to ratepayers. The one subsidiary with which the commission has experience was set up on a stand alone basis.

AL, AZ, AR, CA, CO, CT, DE, DC, FL, GA, KS, KY, LA, MN, MS, MO, MT, NV, NJ, NM, NC, ND, OH, PA, SC, SD, TN, TX, WA, WV -- No answer or not applicable.

7. When considering whether or not to approve the establishment of a subsidiary or affiliate by an electric utility, does your commission consider other potential advantages and disadvantages of the subsidiary or affiliates to ratepayers and stockholders? If so, what advantages and disadvantages are considered?

HI -- This can be addressed only on the facts and circumstances presented in a given situation.

ID -- No authority.

IL -- The Commission may examine or determine what other alternatives are available to the utility company. Market conditions would be evaluated and whether the subsidiary would be obtaining its own financing. The Commission may also examine the type of business the subsidiary will be involved in and whether the business is related to the utility operations.

MA -- If a subsidiary is formed or allowed to be formed the commission would be mostly concerned with the adverse effect on ratepayers, consideration for stockholders is minimal.

MI -- Usually monetary.

NH -- All advantages and disadvantages are weighed against the current company operations. The cost of a consolidated approach to fuel procurement, for instance, is weighed against a company's continued use of internal assets for such procurement. Generally an affiliation or subsidiary provides service to more than one company and the cost savings from that consolidation are consideration in the matter.

NY -- The Commission is most concerned about eliminating cross-subsidization and minimizing the financial exposure of the regulated

does not, however, want to "regulate" the subsidiaries
If the subsidiaries are to operate in a competitive environment, the competitive market forces should be allowed to operate.

OR -- We examine the claimed advantages and look for any potential disadvantages.

AL, AZ, AR, CA, CO, CT, DE, DC, FL, GA, KS, KY, LA, ME, MN, MS, MO, MT, NV, NJ, NM, NC, ND, OH, PA, SC, SD, TN, TX, UT, WA, WV -- No answer or not applicable.

8. Does your commission condition its approval of the establishment of an electric utility subsidiary or affiliate on any particular requirements? If so, please explain. For example, does the commission require that accounts be kept in a certain way.

ID -- No authority.

IL -- Section 12 of the Public Utilities Act states "the Commission may require every public utility engaged in directly or indirectly in any other than a public utililty business, as defined by law to keep separately in like manner and form the accounts of all such other business, and the Commission may provide for the examination and inspection of the books, accounts, papers and records of such other business, in so far as may be necessary to enhance any provision of this Act. The Commission shall have the power to inquire as to and prescribe the apportionment of capitalization, earnings, debts and expenses fairly and justly to be awarded to or borne by the ownership, operation, management or control of such public utility as distinguished from such other business."

The Commission may condition its approval in any manner depending upon the individual circumstances in each proceeding.

ME -- Yes. Not enough history to provide details.

MA -- The commission might impose requirements as to accounting and reports in addition to the annual report requirements.

NH -- The commission has no specific accounting procedures beyond those of the Uniform System of Accounts.

NY -- Yes. Generally, prior to any further investment in the subsidiary, additional Commission authority must be sought, and the subsidiary's activities must be limited to those specified in the company's petition.

OR -- We expect the utility to carefully segregate and account for all expenses and revenues related to its subsidiaries and affiliates.

UT -- The utility would account for the subsidiary according to the chart of accounts.

AL, AZ, AR, CA, CO, CT, DE, DC, FL, GA, HI, KS, KY, LA, MI, MS, MO, MT, NV, NJ, NM, NC, ND, OH, SC, SD, TN, TX, WA, WV -- No answer or not applicable.

II. Questions 9 and 10 are concerned with a utility's financing of its subsidiaries and affiliates and the role, if any, of the state utility commission in that process.

9. How were the investments in electric utility subsidiaries and affiliates secured or otherwise guaranteed? For example, could the faith and credit of the utility have been pledged?

DC -- Owner equity was used in starting subsidiaries. The utility does not guarantee the debt of the subsidiaries.

ID -- The subsidiary must stand alone.

IL -- The investments in electric utility subsidiaries were generally secured by common and/or preferred stock.

MA -- With regard to financing, they may be financed through parent securities issue or retained earnings. Here again, the commission would primarily consider the effect on the ratepayer.

MO -- That's possible. Kansas Power & Light Company arranged to borrow up to $70 million for the purchase of The Gas Service Company's stock under its tender offer.

NH -- Generally through an investment in stocks of the subsidiary.

NY -- Generally, the electric utility's investment in the subsidiary consists of common stock. If the subsidiary requires the guarantee of the parent to issue its debt securities, that must be addressed in the petition by the utility. The source of the utility's funding for these security purchases or guarantee is not securities issued by the utility. The source of funding from the utility is retained earnings. Our law does not permit us to approve of security issuances for nonutility purposes.

OR -- Yes.

UT -- The subsidiary that the commission has had experience with was set up as a wholly-owned subsidiary with the utility only furnishing equity capital.

WA -- No guarantee of subsidiary or affiliates' securities is permitted without prior approval of Commission under the securities statutes RCW 80.08.

AL, AZ, AR, CA, CO, CT, DE, FL, GA, HI, KS, KY, LA, ME, MI, MN, MS, MT, NV, NJ, NM, NC, ND, OH, PA, SC, SD, TN, TX, WV - No answer or not applicable.

10. Has your commission overseen the obtainment by electric utilities of investments and loans to finance the establishment of subsidiaries and affiliates? If so, how?

DC -- The obtainment by electric utilities of investments and loans to finance the establishment of subsidiaries and affiliates will most likely be examined when we have the next rate case. The subsidiaries did not exist in the test year of the previous case.

ID -- See the Utah Power & Light Order No. 18784, abstracted in appendix C.

IL -- Yes. The Commission approves the issuance of all stocks and stock certificates, and bonds, notes and other evidences of indebtedness payable at periods of more than 12 months. Also, no public utility shall, without the consent of the Commission, apply the issue of any stock or stock certificates, or bonds, notes or other evidence of indebtedness, or any part thereof, or any proceeds thereof, to any purpose not specified in the

Commissions's order in excess of the amount authorized for such purpose. This authority is granted to the Commission under Section 20 of the Public Utilities Act.

MA -- Yes. The Boston Edison Company's BEC Fuel Company, because it was cheaper to finance, and also, resulted in saving to the ratepayers.

NH -- Yes. Financing approval was required, for instance by PSNH to set up its "PSNH Overseas Finance, N.V."

NY -- The money needed to establish a subsidiary usually comes from the "utility revenues" which have been booked to retained earnings.

UT -- The commission has authority over the attainment of all equity and debt issues of the utility.

WA -- No, where the guarantees are required of the operating utility.

AL, AZ, AR, CA, CO, CT, DE, FL, HI, KS, KY, LA, MI, MN, MS, MT, NV, NJ, NM, NC, ND, PA, SC, SD, TN, TX, WV -- No answer or not applicable.

III. Question 11 is about the potential advantage of subsidiaries and affiliates to ratepayers and stockholders and the extent to which those advantages have been realized.

11. For electric utilities under your authority that have had subsidiaries or affiliates for a period of time, to what extent have the potential advantages to ratepayers and stockholders been realized? To what extent have the potential disadvantages been realized? Or is it the case that your commission does not formally evaluate this?

AR -- Do not generally evaluate.

CO -- Does not formally evaluate.

GA -- Does not formally evaluate.

ID -- Idaho only looks at affiliates that have direct bearing on utility operation. May ignore separate corporate identity (coal mining).

IL -- The Commission does not formally evaluate the realization of potential advantages or disadvantages. Subsidiaries and their impact on ratepayers are reviewed during rate case proceedings. However, the specific information requested is not readily available.

MA -- The operation of a subsidiary can be reviewed in any rate case--and further answer see question 10.

MO -- Only been evaluated in context of a rate proceeding.

NH -- The Commission has not specifically evaluated the advantages which have been realized as a result of affiliations. Issues raised in ratemaking dockets have supported the position that affiliations have been generally favorable.

NY -- There has been no formal evaluation of the performance of subsidiaries or how they affect ratepayers or stockholders in the case of electric utilities. Our experience appears to show mixed results with losses occurring in the area of uranium procurement activities due to the softening of prices in that market.

ND -- Does not formally evaluate.

OR -- No formal evaluation.

SD -- Commission does not formally evaluate this.

UT -- Not determined yet.

WA -- Does not formally evaluate.

AL, AZ, CA, CT, DE, DC, FL, HI, KS, KY, LA, ME, MI, MN, MS, MT, NV, NJ, NM, NC, OH, PA, SC, TN, TX, WV -- No answer or not applicable.

Questions 12 and 13 ask about commission planning to deal with the challenges presented by electric utilities establishing subsidiaries and affiliates and commission methods for determining the appropriateness of subsidiaries and affiliates.

Has your commission formulated any type of comprehensive strategy for dealing with electric utility establishment of subsidiaries and affiliates? If so, what are the main features of this strategy?

AR -- Legislation is now proposed to deal with this issue. Also, APSC intervenes before FERC or SEC whenever possible as a strategy.

CO -- No.

DC -- A strategy may be developed for the next rate case.

GA -- No (has not formulated strategy); no (is not considering doing so).

HI -- No formulation of strategy on the issue.

ID -- No formal strategy. Will evaluate need on a case-by-case basis.

IL -- The Illinois Commerce Commission has begun a study to develop a comprehensive strategy to deal with electric utilities establishing subsidiaries. The study has just recently (in May 1985) gotten under way and will be completed in approximately six months.

MA -- No-most of our electric utilities are under a holding company and the holding companies form subsidiaries at will (see question 1) and Boston Edison Company is the only exception (see question 10).

MO -- No (has not formulated strategy); unknown (if commission is considering formulation strategy).

NH -- No.

NY -- The Commission has not yet formulated a comprehensive strategy to deal with subsidiaries and appears to favor evaluating each request based on its merits.

OR -- No formal strategy, however, we have an ongoing staff investigation. Since 1974 we have been guided by an Oregon Supreme Court case--PNB vs. Sabin--which upheld the PUC staff's adjustment to PNB's rate base, maintenance and depreciation expense to reduce Western Electric's profits to the level authorized for PNB year by year to 1946 (sic?).

SD -- No.

UT -- The commission has not yet formulated any type of comprehensive strategy.

WA -- No. However, the utility does not have to apply for and obtain approval to transfer any assets used and useful to another utility including affiliated subsidiaries as well as to enter into any agreement or arrangements with affiliated interests.

AL, AZ, CA, CT, DE, FL, KS, KY, LA, ME, MI, MN, MS, MT, NV, NJ, NM, NC, ND, OH, PA, SC, TN, TX, WV -- No answer or not applicable.

13. Are the methods used to determine the appropriateness of electric utility subsidiaries and affiliates currently under review?

AR -- Yes, legislative remedies are under review.

CO -- No.

DC -- Not at present.

HI -- No.

ID -- No.

IL -- Yes.

MA -- Not applicable to holding company system.

NH -- No.

OR -- Yes.

UT -- Yes. One case only.

WA -- Being monitored.

AL, AZ, CA, CT, DE, FL, GA, KS, KY, LA, ME, MI, MN, MS, MO, MT, NV, NJ, NM, NC, ND, OH, PA, SC, SD, TN, TX, WV -- No answer or not applicable.

V. The next set of questions deals with commission regulation of the business relationships between an electric utility and its subsidiaries and affiliates. Questions touch on transfer pricing and cross-subsidization and the allocation of joint operating and administrative costs. We are particularly interested in commission treatment of fuel exploration, fuel development, and fuel transportation subsidiaries and affiliates and any coal mines that may be owned by or affiliated with electric utilities. Please concentrate on these particular subsidiaries and affiliates in your answers to questions 14 through 19. Also, please discuss any utility related versus nonutility related subsidiaries and affiliates in your answers to these questions.

14. Does your commission review the business relationships between electric utilities and their subsidiaries or affiliates on a periodic basis? If so, please describe briefly.

AL -- Yes, the dollar flows and transactions between subsidiaries are reviwed on a periodic basis.

AZ -- No. However, review takes place at major rate hearings.

AR -- Only in the context of rate cases.

CA -- Yes. These relationships are reviewed in connection with general rate applications and if appropriate in other types of proceedings.

CO -- Yes. When the utilities are audited the effects of the subsidiaries or affiliates are also audited.

CT -- Yes. Services to utility must be at cost. Services from utility must be at market. Usually verified at rate cases.

DE -- No. Relatively small scale of operation does not warrant periodic review at present.

DC -- Not currently.

FL -- Three of the utilities under the regulatory jurisdiction of this commission are engaged in business transactions with their affiliates. The reviews conducted on these business relationships are limited primarily to contract compliance.

GA -- No.

ID -- Yes. During the course of each general rate case, the Commission reviews only affiliated transactions to determine if the services provided are at or below the costs of performing the service directly as part of utility operation.

IL -- The business relationships between electric utilities and their affiliates are reviewed during rate case proceedings. In addition, all management, construction, engineering, supply, financial or similar contracts and all contracts or arrangements for the purchase, sale, lease or exchange of any property or for the furnishing of any service, property or thing made with an affiliated interest must be filed and consented to by the Commission.

KS -- At the time of rate case filing, sales volumes, costs, and margins will be evaluated.

KY -- These are reviewed primarily in the context of rate cases.

ME -- Yes. During rate cases.

MA -- Usually if any review is made it is made in a rate case.

MI -- Yes. When doing compliance audits and/or rate case audits the goal is to keep the ratepayers whole.

MN -- No.

MO -- During a rate case proceeding to make sure there is no ratepayers' subsidy to the subsidiary.

MT -- (See note on question #1)

NV -- Yes. Intracompany sales and common cost allocations are audited prior to general rate case proceedings. The commission's Five- and Twenty-Year Resource Plan hearings also consider the impact of subsidiary activities on the cost associated with the balancing and operation of the electric utility.

NH -- Yes, in the context of rate proceedings and during audits by the Commission staff.

NJ -- No.

NY -- The relationship is usually examined during a rate proceeding or when utilities request authority to increase the investment in a subsidiary or form a new subsidiary.

NC -- Pursuant to N.C. General Statute (G.S. 62-51) the Commission has the authority to inspect the books and records of corporations affiliated with public utilities.

In an effort to keep abreast of the scope of the affiliated companies and their impact, if any, on the regulated utilities, the Commission requires the utilities to report annually the value and type of all services rendered by the affiliates to the regulated utility.

ND -- Yes--during rate cases and fuel adjustment clause audits. Under 49-02-02(6) the PSC is required to look at transactions between a utility and an affiliate for unreasonable profit. This is done in each rate case.

OH -- Affiliate and/or subsidiary relationships are reviewed to the extent they have a material impact on the cost of service of the regulated electric utility. This is accomplished via rate case investigations, annual fuel procurement audits and Commission-initiated management audits.

The involvement of Ohio utilities in subsidiary/affiliate enterprises have, to date, fallen into one of three categories:

1. Activities too small to materially impact regulated services or costs;

2. Vertical integration type activities which can be treated as fully integrated for ratemaking purposes, obviating subsidy concerns; or

3. Convenience subsidiary arrangements, i.e., "paper," which create separate accounting or reporting entities generally for financing purposes. These, too, can be interpreted for ratemaking purposes.

OR -- Yes, in all rate cases.

PA -- Attached is Chapter 21 of Title 66 of the Public Utility Code. This chapter addresses the relations with affiliated interests. Affiliated interest filings are generally reviewed by the Electric Division and if found in the public interest are generally accepted. However, this acceptance is not binding for rate purposes. §2106 of the Public Utility Code addresses the effect on rates.

During rate proceedings, our attention is generally directed to the relationships between a service company and utility. For example, Allegheny Power System Service Company and West Penn Power Company; GPU Service Company and Met Ed and Penelec; GPU Nuclear and Met Ed and Penelec. Only if there is evidence that personnel and/or facilities are dedicated to other than utility service would we address this issue. These business relationships are also reviewed through Management Audits on a five to eight year cycle.

SC -- The Commission formerly did extensive review of Duke Power Company's relationship to its three affiliated coal mining operations. Duke has disposed of two of these affiliates, but still maintains one relationship. This relationship is always reviewed at the Commission's required semi-annual fuel hearings. The same review procedures were applicable for CP&L, however, CP&L is in the process of disposing of its affiliated coal mining operation.

SD -- No.

TX -- The Commission reviews affiliate transactions in connection with rate proceedings and/or fuel proceedings. The Commission's rules also require that an operational audit be performed for fuel affiliates.

UT -- The Commission would review the business relationships between a utility and its subsidiary.

WA -- Yes, if these relationships result in services or goods being used by the utility, the cost of which is part of the operating expenses or rate base used in setting rates for the Washington ratepayers.

WV -- When Appalachian Power Company owned coal producing subsidiaries, the West Virginia Commission repriced its production to the market if its prices were higher than market. APCO sold these subsidiaries in 1984.

We review service company charges in the context of an annual or semiannual fuel review case.

We review captive coal transactions in the context of an annual or semiannual fuel review case.

HI, LA, MS, NM, TN -- No answer or not applicable.

15. Does your commission attempt to isolate and control the possible problem of pricing of goods and services transferred between an electric utility and its subsidiaries or affiliates? If so, what methods does the commission use? Does the commission examine the prices and terms of transactions between an electric utility and its subsidiaries or affiliates? Does the commission control or regulate the purchases between an electric utility and its subsidiaries and affiliates?

AL -- This Commission determines the reasonableness of pricing between utilities and subsidiaries. It also regulates the purchases or sales between an electric utility and its subsidiaries to the extent of prudence.

AZ -- No. We do regulate the transfer of capital stock (rate base) from a parent to a subsidiary and any other disposition of parent property.

AR -- Again, in context of rate cases. The criteria are traditional, i.e., whether the transaction/expense is reasonably related to the cost of providing electric service to Arkansas ratepayers.

CA -- If it is determined that transactions between a utility and its affiliates are not reasonable, the Commission can, and has in the past, disallow for ratemaking purposes excessive prices paid to affiliates for products and/or services.

CO -- To the extent that costs can be traced on the utilities' books and records, all electric utilities are required to use the equity method of accounting which in theory separates subsidiary costs. The Colorado Commission does not have an affiliate interest statute.

CT -- Yes, see the response to question #14.

DE -- No such control has yet been exerted.

FL -- The Commission does not regulate transactions between affiliates directly. However, the Commission does allow certain costs to be passed on to the ratepayer. Currently, the Commission allows these affiliates to price these transactions at cost. Except for the one service company, this cost will include a rate of return on equity equal to the mid-point of the utility's allowed range. This return on the affiliates' equity raises an issue relating to prudent capital structure. The Commission has recently opened an investigative docket which will consider basing the cost of these transactions, to be recovered from the ratepayers, on the market price.

GA -- No.

HI -- Attempts are made whenever goods and services are transferred between regulated affiliates and the same principle would apply in the regulated-non-regulated arrangement.

ID -- Yes. The only subsidiaries providing service to utility operations are coal mines. The IPUC rolls the subidiaries' investment and operating results into utility operations so that subsidiaries operates at same level as authorized for utility.

IL -- The Commission does attempt to control pricing of goods and services transferred between an electric utility and its subsidiaries. As stated in the answer to question 14, electric utilities must file a petition for all management, construction, engineering, supply, financial or similar contracts and all contracts or arrangements for the purchase, sale, lease or exchange of any property or for the furnishing of any service property or thing made with an affiliated interest. Exceptions to this provision of the Public Utilities Act are cases involving:

1. Contracts or arrangements made in the ordinary course of business for the employment of officers or employees.

2. Contracts or arrangements made in the ordinary course of business for the purchase of services, supplies, or other personal property at prices not exceding the standard or prevailing market prices, or at prices or rates fixed pursuant to law.

3. Contracts or arrangements where the total obligation to be incurred thereunder does not exceed $500.

4. The temporary leasing, lending or interexchanging of equipment in the ordinary course of business or in case of an emergency.

5. Contracts made by a public utility with a person or corporation whose bid is the most favorable to the public utility, as ascertained by competitive bidding under such rules as may be prescribed by the Commission.

KS -- See response to question #14 (at the time of a rate case filing--sales, volumes, costs and marginals will be evaluated).

KY -- These are controlled to the extent of allowances or disallowances in rate cases.

LA -- Yes. There are several general orders pertaining to a utility's transactions with subsidiaries.

ME -- It could if it wanted to but it hasn't.

MA -- Usually in a rate case, some inquiries may be made as to cost allocation.

MI -- Yes. Comparison to third-party prices are made and rates set as though the subsidiary's earned return was at or below the utility's authorized return (on common equity).

MN -- Yes. The utility and its subsidiary share a coal inventory. The coal taken out of inventory is valued the same for both. The Commission will examine transactions during a rate case to determine utility prudence and reasonableness.

MO -- We make sure that any expenses incurred are charged to the subsidiary at the appropriate rate. Most subsidiaries are non-utility type so no goods would be transferred.

NV -- Yes to all questions.
The commission considers the prudence of intracompany transactions and the reasonableness of the associated prices or costs.

NH -- Yes. Any pricing problems are determined through an audit and are presented to the Commission for resolution through a rate case or fuel clause hearings.

NJ -- The Board of Public Utilities does not specifically or directly control pricing of goods and services between an electric utility and its subsidiaries or affiliates. But the Board has statutory jurisdiction under New Jersey Statute 48:3-7.1 (see appendix C) which requires Board's approval of service contracts, over a specific amount, between N.J. utilities and their subsidiaries. The Statute also requires that the price or compensation for the property or work performed under the contract should be fair. Pursuant to this statute the Board conditions its approval of service contracts that the services will be rendered at cost. All such charges are subject to scrutiny by the Board at the time of the rate proceedings. Also, in New Jersey we have a Public Advocate who represents the public in all rate cases. The Public Advocate participates actively in all major rate cases before this Board.

In addition, the Board's Staff participates in the comprehensive examination of the utilities' books and records conducted by the Federal Energy Regulatory Commission (FERC) mostly every three year period. Special attention is given to all transactions with the subsidiaries or affiliates.

NY -- The Commission reviews pricing and uses the appropriate allocation of cost based upon the circumstances. For example, if a subsidiary is operating as a utility and/or is providing utility services, it will likely include the subsidiary's operations in rates on the same basis as typical utility plant and costs. Such is the case with the Somerset Railroad, which provides coal transportation to NYSE&G's Somerset Coal Station.

NC -- Yes, the Commission allows the regulated utilities to pay only competitive prices for items and services received from its affiliates. Where competitive pricing is difficult or impossible to establish, the Commission will allow the prices to contain an element of profit or return on investment not to exceed the most recent rate the Commission set in the utilities general rate case.

ND -- Yes. Criteria are:

> At What price could the coal have been purchased on the open market?
>
> Does the mining subsidiary sell coal to other utilities at prices lower than those charged its parent?

OH -- As part of a routine investigation of any utility in a rate application, the Staff of this Commission is expected to express an opinion on the overall reasonableness of the expenditure level included in the application. If a portion of these expenditures are attribuable to services or purchases of an affiliated company, they are generally reviewed for reasonableness. Reasonableness is often determined in a variety of ways. It can be reviewed as a percentage of total, comparison of comparable prices, or any other means that the Staff determines necessary during its investigation. If the Staff disagrees with the reasonableness of an expense level or the service provided, an adjustment can be made to exclude the expense from the rate proceeding. The prices and terms of transactions between utility and subsidiaries or affiliates are examined. The Commission does not directly control or regulate purchases between a utility and its subsidiaries or affiliates, but inclusion of cost of such transactions is only authorized after scrutiny and a determination of reasonableness.

OR -- Very definitely. Bridger Coal, a PP&L affiliate, is constrained to earn no more on its sales to PP&L than PP&L is allowed for its utility operations.

PA -- Yes. Through the filing of affiliate interest contracts or arrangements and the examination of affiliate interest charges in rate case proceedings. The Commission also uses the management audit process to examine these issues.

SC -- The Commission does attempt to isolate the price of goods and services from affiliated sources. The Commission's procedure for review consists of generally examining the policy and then sampling random transactions to test the policy.

SD -- Sometimes; return basis; no; no.

TN -- Yes.

TX -- The Commission's rules allow the cost of fuel excluding equity return to be included in its fuel cost. The equity return may be included in other base rates after a reasonable return on equity has been determined in a rate proceeding.

VT -- The price of power purchased from the subsidiary was set at the authorized PURPA rate.

WA -- Only for ratemaking, with the standard being the affiliate/subsidiary's cost plus a fair return (the same as the utility) on the associated investment.

WV -- See the response to question 14.

DC, MS, MT, NM -- No answer or not applicable.

16. When examining the prices and terms of transactions between an electric utility and its subsidiaries or affiliates, does your commission compare the costs of goods and services supplied to the utility by its subsidiaries or affiliates with the market price of such goods and services? If so, how does the commission determine the market prices? If not, does the commission employ some other standard?

AL -- Yes, other prices by suppliers are checked and used as a standard.

AZ -- At a rate case it may be determined that a utility paid too much for a good or service from one of its subsidiaries. The lower price would be determined by observing the price at the time of purchase, offered by some unaffiliated supplier that the parent company ignored. The additional costs incurred by the parent firm would not be allowed in the base year operating costs. Such an event has not occurred, as yet, with an <u>electric</u> utility in this state.

AR -- No. The standard to date has been whether the jurisdictional utility could provide the same service in-house.

CA -- In its review process the Commission whenever possible will make a comparison of the market price of the goods or services. However, in many instances, market data is not available. If market data is not available the Commission reviews the terms of any contracts or agreements between the utility and its affiliates to determine the reasonableness of the costs.

In every instance the Commission reviews the earnings of the affiliates to insure that the affiliates are not earning a rate of return greater than that authorized for the utility, and has in many cases made ratemaking adjustments to reduce the costs to reflect the higher earnings of affiliates.

CO -- Yes, the utility cannot purchase fuel from its own subsidiary above the spot market prices of fuel.

CT -- Must use cost.

DE -- Not applicable.

FL -- Where possible, the Commission does compare affiliate transactions with market indicators. The Commission does so by identifying similar transactions on the open market and comparing the cost of these "open market" transactions with the affiliates' transactions.

HI -- Not applicable as there is no experience factor.

ID -- No. See the response to question 15.

IL -- The Commission does compare the costs of goods and services supplied to the utility by its subsidiary with market prices. This comparison is done at the time the utility files for approval of the affiliated interest transaction and also during rate proceedings. However, the Commission shall not require a public utility to make purchases at prices exceeding the prices offered by an affiliated interest, and the Commission shall not be required to disapprove or disallow, solely on the ground that such payments yield the affiliated interest a return or rate of return in excess of that allowed the public utility, any portion of payment or payments for purchases from an affiliated interest.

KS -- Yes; the Commission obtains the costs of similar goods or products supplied or available within the utilities' operating boundaries.

KY -- No.

LA -- In the area of fuel procurement, the commission has ruled and promulgated orders to the effect that fuel procurers shall not make any profit in acquiring or transporting fuel for an electric utility.

MA -- Usually, no depth comparisons are made.

MI -- Yes. See the response to question 15. Comparison made to third party price and rates set as though the subsidiary's earned return was at or below the utility's authorized return on common equity)

MN -- Not applicable; the utility does not purchase from its subsidiary.

MO -- If the utility could buy the same item from another place (such as coal), we would. Most of the subsidiaries are nonutility related.

NV -- Yes. Electric sales to the water subsidiary are priced at the cost to generate and transmit on a gross kwh basis. NOTE: Intra-company "profit" is eliminated via the consolidation process.

NH -- Yes. The Commission staff compares the market price by comparisons with other sources of supply.

NJ -- See response to question 15.

NY -- No. Generally the Commission employs the concept of original cost.

NC -- See answer to question number 15:

> Yes, the Commission allows the regulated utilities to pay only competitive prices for items and services received from its affiliates. Where competitive pricing is difficult or impossible to establish, the Commission will allow the prices to contain an element of profit or return on investment not to exceed the most recent rate the Commission set in the utilities general rate case.

ND -- Yes. Outside consultants.

OH -- As described in the response to question 15, the Staff uses many means to determine the reasonableness of an expenditure. Market price comparisions have been used as determination of reasonableness.

If the information is available, the Staff will use a competitor's price of a similar product or service as a guide to the current market price.

OR -- We don't use a market price concept, however we would not allow a utility to receive more than market price and we have a general awareness of market prices (without conducting formal studies).

PA -- As previously discussed, we generally review the costs for service performed by an affiliate during a rate proceeding. We review the method used to allocate cost and how the cost was determined. Management audit consultants also attempt to determine if the service can be provided more economically outside the utility.

SC -- As stated in question #15, policies are reviewed. Whenever it is possible, prices are compared from nonaffiliated sources. This has always been done with regard to coal purchases because the review was so extensive.

SD -- No; return basis

TN -- The commission uses a test of "reasonableness" when examining transactions that are not at arm's length between two companies. The same standard of reasonableness is applied to the fuel adjustment clause for purchased power from affiliated companies.

TX -- The cost of goods and services provided by a subsidiary or an affiliate to be included in the cost of service is controlled by criteria set forth in the Public Utility Regulatory Act, Article VI, Section 41(c)(1). The criteria set forth in this provision are an overall finding of reasonableness of cost and that the cost can be no higher than that charged to other affiliates or unaffiliated persons or corporations.

UT -- Power would be purchased only at the authorized PURPA rate.

WA -- Not market price. The standard is the cost to the affiliate of the goods and services plus a fair return on the affiliates/subsidiaries' investment associated with such goods or services.

WV -- Yes. See the response to question 14. Cost of service approach used for Allegheny Generating Company. Prorations are checked for reasonableness.

DC, GA, ME, MS, MT, NM -- No answer or not applicable.

17. When examining transactions between an electric utility and its subsidiaries or affiliates and the provision of goods and services by the subsidiaries and affiliates to the utility, does your commission attempt to determine the affiliates' and subsidiaries' costs of service? If so, how does the commission do this? Does the commission attempt to regulate the affiliates' and subsidiaries' costs of service? If so, for what purpose.

AL -- No.
AZ -- No.

AK -- We may only regulate jurisdictional utilities.

CA -- The commission does not regulate subsidiaries' cost of service.

CO -- No.

CT -- Transactions must be at cost. Cost is determined from invoices, payroll records, etc.

DE -- Not applicable.

FL -- The commission generally relies on financial audits conducted by independent CPA firms to determine affiliates' and subsidiaries' costs of service. The commission staff reviews these audits to determine whether any particular items warrant further investigation.

HI -- An informative response is not available, due to the commissions' lack of experience with these transactions.

ID -- No. (But see the response to question 15).

IL -- The Commission, as a general rule, does not attempt to determine the affiliates' and subsidiaries' cost of service. The accounting methods between a utility and subsidiary are generally reviewed in the proceeding to approve the formation of the subsidiary. The Commission does determine that the terms and conditions of transactions with affiliated interests are as good as or better than terms and conditions available through non-affiliated sources. However, the Commission shall not require a public utility to make purchases at prices exceeding the prices offered by an affiliated interest, and the Commission shall not be required to disapprove or disallow, solely on the ground that such payments yield the affiliated interest a return or rate of return in excess of that allowed the public utility, any portion of payments for purchase from an affiliated interest.

KS -- The commission has not attempted to determine the affiliates' and subsidiaries' cost of service when examining transactions between an electric utility and its subsidiaries or affiliates. Such an evaluation has been done in the telephone industry.

KY -- No.

MA -- Service companies are supposed to operate at cost. No in-depth studies are available.

MI -- The utilities cooperate in determining the subsidiaries' cost of service. The commission does not regulate the nonenergy subsidiary. Again, the commission's purpose is to keep the ratepayers whole and the lights on.

MN -- No.

MO -- A reasonable allocation.

MT -- Uncertain.

NV -- The water and gas subsidiaries are regulated by the commission. Non-utility affiliates are not regulated. Common costs and prices are revived by staff auditors and approved or disapproved by the commission based on prudence and reasonableness. Industry averages, regional price trends, and general economic conditions are a basis for these determinations.

NH -- Yes. Oversight is accomplished by requiring affiliated contracts to be filed, and by staff studies to determine that the costs are fair and reasonable.

NJ -- See the response to question 15.

NY -- Yes, through an audit.

NC -- See the response to question 15.

ND -- No.

OH -- The Staff of the Commission does not usually review the entire cost of service of the affiliated company. In connection with a rate application only the expenditures that are included in the rate application are subject to review. However, in some instances where Staff requested access to affiliated companies' books, no objections were raised.

OR -- Yes. We determine their return on sales to the utility by examination of the affiliates' accounting records. While we don't regulate the affiliate, we do make rate case adjustments to the utility based on the affiliate.

PA -- We generally review the costs for service performed by an affiliate during a rate proceeding. We review the method used to allocate cost and how the cost was determined. Management audit consultants also attempt to determine if the service can be provided more economically outside the utility.

SC -- The staff has always reviewed the cost of service for Duke & Carolina Power Light with regard to its coal affiliates. This is done for GENCO, a subsidiary of NEWCO, which sells all of its power to South Carolina Electric & Gas. NEWCO is the holding company for SCE&G.

TX -- The Commission has used a cost of service approach for fuel affiliates to determine the reasonableness of cost. The Commission regulates the affiliates' cost of service only to the extent that reasonable costs are included in the regulated utility's cost of service.

UT -- No attempt to look at the subsidiary's cost of service is contemplated.

WA -- 1st question--Yes.
2nd/4th question--Don't regulate affiliate/subsidiary's costs of service. Use affiliate/subsidiary's actual cost plus fair return as substitute for the amount billed and paid by the utility.

WV -- See the response to question 14.

DC, GA, LA, ME, NM, SD TN, -- No answer or not applicable.

18. Does your commission have a procedure for examining the joint administrative costs of an electric utility and its subsidiaries in order to control the possible problem of cross-subsidization? If so, does your commission use any particular method or formula for separating the administrative and other operating costs of the utility from those of its subsidiaries? What types of documentation does the commission require as proof of those costs?

AL -- This Commission does not have procedures for examining joint costs but audits have been periodically conducted to determine validity. Records of these cost separations must be completed.

AZ -- No.

AK -- No.

CA -- Joint administrative costs are reviewed in every rate proceeding as well as the methods used to allocate those costs.

Periodically the commission uses a direct allocation whenever possible, such as actual time and cost. When direct allocation is not possible, various methods have been used depending on the circumstances.

Since joint costs for California companies originate in the utilities, documentation is not a problem at this time.

CO -- Joint costs are reviewed during utility record audits.

DE -- No.

DC -- The allocation of joint administrative costs will be reviewed in the next rate case.

FL -- Once again, the Commission relies on audits conducted by independent CPA firms to verify that administrative and overhead costs have been properly allocated to affiliates and subsidiaries.

GA -- No.

HI -- In the regulated situation that is the regulated parent performing services for the regulated subsidiary, this transaction cost has been the most difficult to isolate. Substantial examination has occurred in the rate case for this item. We suspect the same problem would occur where a nonregulated subsidiary or affiliate is involved.

ID -- Yes. See the response to question 15.

IL -- Cost allocation methodologies are determined or reviewed by the Commission at the time the subsidiary is formed. The methods or formulas needed for cost allocations to prevent cross-subsidization are determined on an individual company or account basis.

KS -- Not specifically evaluated in the context of a rate filing.

KY -- Jurisdictional allocation study.

LA -- Under normal commission procedure, a rate case would involve the allocation of costs, both administrative and otherwise. When a subsidiary exists, the allocation is made by means of a commission-approved formula which would be appropriate to the circumstancess. Such formulas could be, and often are developed on an individual basis.

MA -- There are no procedures or criteria to examine administrative costs of subsidiaries; generally it is a judgment and an "arm's length" approach.

MI -- Yes. No set allocation is used. The commission requires number of employees, time spent on each subsidiary, etc., as proof of costs.

MN -- There is no set procedure. Cost allocation is thoroughly investigated during a rate case.

MO -- Formula--none. The commission has not established specific documentation requirements, but each case is handled during a rate case audit.

MT -- Uncertain.

NV -- Common costs are allocated based on percentage of net plant. Revenue generation is considered as an allocation basis when no other basis is reasonable or germane.

NH -- No. However, the commission has regulatory authority to document any proof of all charges.

NJ -- See the response to question 15.

NY -- Yes. Yes. For example, time sheets would be used to allocate payroll.

NC -- The Commission has no set formula for the allocation of joint administrative and overhead costs for use in its effort to prevent cross-subsidization, however, it does require each regulated company to provide its method of cost allocation and defend the fairness and reasonableness of the costs allocated.

ND -- No.

OH -- As a part of rate case investigation, the Staff has requested that a utility describe all of the services provided by an affiliated company so that they can be reviewed for accuracy, reasonableness, proper allocation, and possible cross-subsidization. This is not an established Commission procedure, but a part of an audit program followed by the Staff in its investigation.

OR -- No formal procedure; however, we do examine the reasonableness of cost allocations. We also periodically audit the utility.

PA -- No.

SC -- The Commission reviews the factors that are employed by the companies to separate costs between utility and nonutility operations. This is done in conjunction with rate case audits. Basically, current factors are compared with previously approved factors and growth in utility and nonutility operations is compared. Also, the basis behind the factors are reviewed for logic on an ongoing basis.

SD -- No.

TX -- The Commission staff, in connection with a rate proceeding, reviews inter-corporate billings and cost allocations. A formula approach is not used as a rule. If the affiliates have a formula approach, it would be reviewed for reasonableness. Proof of costs are usually in the form of invoices, payroll records, and contracts and other documentation as provided. Review of the utility's external auditor's consolidated and affiliate work papers is performed to assess existing internal controls for the recording of affiliated transactions.

UT -- The commission does have the authority over joint administrative costs and would look at them on a case-by-case basis. No particular method is used as this time.

WA -- No procedures have been established. Subsidiary books reflecting only its operations, including all its own staff. These books are examined to ensure all its costs are reported.

WV -- See previous responses.

CT, ME, MS, NM, TN -- No answer or not applicable.

19. For electric utilities with subsidiaries or affiliates, does your commission require that either the utilities or the subsidiaries and affiliates keep their accounts in a certain way? If so, what accounting procedures are required? Does your commission require the costs of the subsidiary to be separated from those of the utility? If so, how are the costs separated?

AL -- The records are maintained according to the Uniform System of Accounts and in addition, records of subsidiaries or affiliates must be kept apart for audit purposes.

AZ -- The parent company must use the FERC U.S.A. The subsidiaries accounts are not solicited. Items and services purchased by the parent appear as operating costs of the parent; sales appear as revenues.

CA -- No. the commission does not require that either the utilities or the subsidiaries keep their accounts in a certain way. Yes, the commission does require the costs of the subsidiary to be separated from those of the utility. Usually, the subsidiaries operate separately with separate accounting records, otherwise through separate accounts.

CO -- The utility is required to book costs according to the FERC Uniform System of Accounts. The affiliate costs are required to be segregated as they affect the utility. The accounting of the subsidiary or the affiliate themselves are not within our authority.

CT -- No.

DE -- Electric utilities follow the FERC Uniform System of Accounts. Subsidiaries are unregulated.

FL -- Electric utilities are required to maintain their books and records in accordance with generally accepted accounting principles and Commission requirements. Accounts are required to be maintained according to FERC' Uniform System of Accounts. Since this Commission does not regulate subsidiaries or affiliates, there is no requirement concerning the maintaining of accounts. In general, however, the subsidiaries or affiliates would follow generally accepted accounting principles and industry practices.

GA -- No.

HI -- In the case of regulated utilities, the prescription for the Uniform System of Accounts would be identical. In the non-regulated subsidiary situation, there is no experience to share.

ID -- No. The IPUC only requires that nonutility subsidiaries and affiliates be properly segregated.

IL -- Section 12 of the Illinois Public Utilities Act states "the Commission may require every public utility engaged directly or indirectly in any other than a public utility business, as defined by law to keep separately in like manner and from the accounts of all such other business, and the Commission may provide for the examination and inspection of the books, accounts, papers and records of such other business, in so far as may be necessary to enforce any provision of this Act.

In addition, the Illinois Commerce Commission has established the following accounts in the Uniform System of Accounts for Electric Utilities:

417 - Revenues from nonutility operations

417.1 - Expenses from nonutility operations

418.1 - Equity in earnings of subsidiary companies

123 - Investment in associated companies

123.1 - Investment in subsidiary companies

These accounts keep the costs of the subsidiary separate from the utility.

KS -- The commission has recommended that separate accounting records be maintained.

MA -- Occasionally allocations and joint costs are reviewed. Generally the subsidiaries keep separate records and there is no specific mandate as to the type of records kept.

MI -- The Michigan PSC has a Uniform System of Accounts.

MN -- The commission requires the utility to keep its accounts so that costs attributable to the utility may be separated. This basically requires accounting for the invoices or additions to and withdrawals from the coal pile, and separate assignment in the few cases where utility labor is employed by the subsidiary.

MO -- Yes. A company must keep costs separate and this is audited in a rate case proceeding.

MT -- Uncertain.

NV -- Separation of costs is preferred, however, when separation of costs is not practical or cost beneficial, the allocation method outlined in our answer to question 18 is utilized.

NH -- The Uniform System of Accounts is the standard for accounting procedures. The cost of the subsidiary is separated from those of the utility. The costs are separated by using "below the line accounts."

NJ -- See the response to question 15.

NY -- Yes for utilities; no for subsidiaries. Yes. Each cost is allocated on some basis.

NC -- The commission strongly recommends that all identifiable costs be kept separate and that generally accepted accounting principles be utilized in the record keeping process.

ND -- For utilities, yes, the NARUC Uniform System of Accounts is required. For affiliates, no.

OH -- This Commission does not regulate the accounting procedures of nonregulated affiliates. Regulated utilities are required to follow the Uniform System of Accounts prescribed by the Commission.

OR -- We require the Uniform System of Accounts and that costs of the subsidiary be segregated.

PA -- The commission, during its review of certain affiliate interest contracts, has required separate accounting procedures.

SC -- Generally speaking, the answer to this question is no. However, from time to time, this might be necessary as it was when affiliated coal costs were higher than nonaffiliated sources and a deferral had to be established for excessive coal costs.

SD -- No, the commission does not require the utilities, the subsidiaries, and the affiliates to keep their accounts in a certain way.

Yes, the commission does require the costs of the subsidiary to be separated from those of the utility.

Normal allocation procedures are used during rate cases to separate costs.

TX -- The Commission does not specifically dictate a chart of accounts for all utilities. However, affiliate charts of accounts in rate proceedings have been reviewed and approved on a case by case basis.

UT -- Separate books and records are required with the utility required to keep its books according to the system of accounts.

WA -- 1st/2nd questions--no. However, generally accepted accounting principles shall be followed.

3rd/4th questions--separate books are maintained, and income and expenses of subsidiary are separated from the operating utility accounts. This is done as a part of good accounting practice.

WV -- No, for coal. Yes for generating company; the FERC Uniform System of Accounts is used.

AR, DC, KY, LA, ME, MS, NM, TN -- No answer or not applicable.

VI. Questions 20 and 21 deal with commission policies on the allocation between ratepayers and stockholders of any earnings a utility may receive from either the operation or the sale of its subsidiaries.

20. Does your commission have any set formula for the allocation of profits (between ratepayers and stockholders) resulting from the electric utility's subsidiary? If so, what is the formula? Does it tend to favor one group over the other?

AL -- No set formula has been established because profits revert to the stockholders. These subsidiaries and affiliates are nonjurisdictional.

AZ -- No.
AR -- No.

CA -- No. Each case is reviewed independently and consideration is given to the particular facts and circumstances.

CO -- All profits or losses of the subsidiaries or affiliates are separated from the utilities' profits. The ratepayer benefits or loses only through the effects on costs of capital. The commission modifies the costs of capital for loss effects.

CT -- No.
DE -- No.
DC -- No.
FL -- No.
GA -- No.

HI -- Not applicable where a nonregulated subsidiary is involved.
For the regulated situation, each utility's return is determined independently of the other.

ID -- Subsidiaries or affiliates must stand alone and separate from utility operations if in an unrelated business. Profit and/or loss flows to shareholders.
Subsidiaries in <u>related</u> businesses providing service to utility are allowed same return as utility for services performed (coal mining - see the response to question 15).

IL -- The Illinois Commerce Commission has established Account 418.1 - Equity in earnings of subsidiary companies, 417 - Revenues from nonutility operations and 417.1 - Expenses from nonutility operations. These accounts are below the line items.

KS -- No.

KY -- No.

LA -- In the area of fuel procurement, the subsidiary shall not make any profit in acquiring or transporting fuel for an electric utility.

ME -- 100 percent to ratepayers.

MA -- There is no set formula for allocation of profits. Service companies operate at cost, under SEC rules, and subsidiaries' profits are generally separate or "below the line."

MI -- No.

MN -- In the case presently operating, the profits (and risks) of the subsidiary are assigned entirely to the shareholders. A statement has been made that in the future, the commission would prefer assignment of approximately 5 percent of the profits of the subsidiary to the utility ratepayers to compensate them for unquantifiable costs.

MO -- No set formula. If the subsidiary is nonutility and no ratepayers' money is involved, then there is no reason to control the profit or loss.

MT -- Uncertain.

NV -- Regulated subsidiary "profits" are audited annually; authorized return on equity and ORR amounts are verified, with under- and overearnings brought to the attention of the commission. Adjustments, if approved, are implemented via show cause or deferred energy hearings.

No set formula is applied other than the original rate of return calculation and financial integrity model.

NH -- No.

NJ -- For accounting purposes, the investment in a subsidiary and any profit or loss from that investment is treated on the books and records of an operating utility in accordance with the Uniform System of Accounts prescribed by FERC. The Board adopts this Uniform System of Accounts insofar as it is in accordance with the Board's policies and procedures. Therefore, the Board under its general statutory jurisdiction may require different treatment of the utility investment during the rate case proceedings. Specifically, in the 1984 rate case involving the Public Service Electric and Gas Company, profit from the nonutility subsidiary Energy Development Corporation (EDC) was included in the utility's operating income. As an offset the related amount of investment in the subsidiary was also included in the rate base.

NY -- No.

NC -- The Commission does not require the utilities to share any of the profits from purely nonutility affiliated operations. For example, one of the electric utilities sells appliances and is a distributor of electrical supplies and equipment and none of the profits or losses from these operations are shared with the ratepayers. On the other hand, this same electric utility has owned coal mines and the Commission has allowed some losses from these operations to ultimately be charged to the ratepayers.

ND -- No.

OH -- This Commission does not have a formula to allocate profits of nonregulated affiliated companies. Regulated utilities are treated on a stand-alone method under which a utility is considered basically on its own merits and not on the merits of its affiliates or subsidiaries. A stand-alone method, however, considers all costs entering into the utility's jurisdictional cost of service, without increases or decreases for gains or losses related to other entities.

OR -- No set formula.

PA -- No.

SC -- No, the Commission has always looked at the operations separately. Specifically, as long as the utility is not subsidizing nonutility operations and it does not represent a detriment to the utility, the Commission has not looked at profits or losses from nonutility operations. However, our Commission has looked at the ratepayer's rates. This has been done by reviewing prices that the utility pays to affiliates and reviewing the allocation of costs between utility and nonutility operations. For example, the prices for coal was limited to cost, plus a return normally allowed for the utility operations.

SD -- No.

TX -- The Commission does not use a formula to allocate profits from subsidiary or affiliate between the stockholders and ratepayers.

UT -- The subsidiary in Utah was set up on a stand alone basis with the ratepayers receiving none of its profits or losses.

WA -- No formula adopted. Use a case-by-case approach.

WV -- No.

MS, NM, TN -- No answer.

21. Have there been any instances in which electric utilities have sold an unregulated subsidiary? In those cases, how did your commission decide who, ratepayers or stockholders, should benefit from any earnings from the sale?

AL -- This has not happened to date.

AZ -- No. However, Tuscon Electric Power has been forming subsidiaries with its generating plants.

AR -- No.

CA -- Yes, there have been instances in which electric utilities have sold an unregulated subsidiary. The decision of who should benefit from the earnings from the sale have varied depending on the particular circumstances of each case.

CO -- We have not had this occur; however, the FERC Uniform System of Accounts would apply.

CT -- None.
DE -- No.
DC -- No.

FL -- No. However, during reorganizations in which holding companies were created, subsidiaries of the electric utilities were transferred to the holding companies and became affiliates of the utilities.

GA -- No.

HI -- Not applicable due to non-experience.

IL -- To the best of our knowledge, there have been no instances in which electric utilities have sold an unregulated subsidiary.

KS -- None, to the best of my knowledge.

KY -- None.

LA -- The commission has ordered that no sale, lease, or merger shall take place which involves more than 1 percent of the assets of a public utility absent a commission expression of non-opposition. The sale, lease, or merger by any public utility of any of its assets--which would presumably include a subsidiary--would fall under this order. A commission expression of non-opposition could be obtained formally or informally, depending on the case. In any event, this procedure would allow the commission to examine both the short- and long-term effects on rates and services caused by the disposition of assets.

ME -- No.

MA -- We have had no such case, and therefore no decisions.

MI -- No.
MN -- No.

MO -- No, none. However, if only stockholders' money was used, they should get the benefit.

MT -- Uncertain.

NV -- No.

NJ -- There has been no sale of an unregulated subsidiary by an electric utility. But, at least in one instance where the Board had to approve a service contract between JCP&L and its 44% owned subsidiary of limited duration, Saxton Nuclear Experimental Corporation (SNEC), the Board's Order provides that upon termination of SNEC project the disposition of that proportion of assets related to JCP&L shall be subject to the approval of the Board (Order Docket No. 694-167 abstracted in appendix C).

NY -- None to my knowledge.

NC -- Two electric utilities have sold coal mining subsidiaries at losses and in each case the companies asked the Commission to have the ratepayers share in the losses. The disposition of the losses on the sale of these properties can and probably will be items raised by the companies in future general rate case proceedings.

In both of these cases, the regulated utilities entered the coal mining operations with the approval of the Commission.

ND -- No.

OH -- There has been no sale of nonregulated subsidiaries of Ohio electric utilities in recent times.

OR -- Probably. No formal determination.

PA -- We can't recall any recent sales. However, since the Commission does not have jurisdiction over such transactions, benefits and/or losses would go to stockholders.

SC -- Yes. Duke Power Company sold its Eastover Mining Operations. The sale involved a loss and since the business venture was for the purpose of assuring a supply of coal, the Commission allowed Duke to recover a portion of its loss from ratepayers over an amortization period of ten years.

SD -- Yes, there have been instances in which electric utilities have sold an unregulated subsidiary.
No, the commission did not determine who should benefit from any earnings from the sale.

TX -- From a theoretical standpoint, the Commission would limit the sharing of benefits arising from the sale of a subsidiary to the extent that the ratepayers had contributed to the profits or equity of the subsidiary.

UT -- No instances.

WA -- No.

WV -- Yes (see the response to question 14). The profit from Appalachian Power Company's sale of coal producing subsidiaries during 1984 has yet to be addressed.

ID, LA, MS, NH, NM, TN -- No answer or not applicable.

VII. Questions 22 and 23 deal with two different types of commission authority: the authority to gain access to the books and records of electric utility subsidiaries and affiliates (or to the records of a holding company parent of an electric utility) and the authority to order an electric utility to divest itself of its subsidiaries or affiliates.

22. Does your commission have authority to gain access to the books and records of electric utility subsidiaries and affiliates or to the records of the holding company parent of an electric utility? If so, have company officials been cooperative? What types of problems has your commission encountered in reviewing the corporate records?

AL -- To date, access to books and records of electric utility subsidiaries has been granted upon request.

AZ -- We have no direct authority. If company officials were uncooperative, we could obtain records through subpoena. However, in practice, company officials have always been cooperative. In the case of a parent utility and its subsidiary, the parent must give us any data it has and any it has access to. As a stockholder in its subsidiary it has access to those accounts, and hence, we have authority indirectly.

AR -- Yes. Generally cooperative. Problems have been primarily the delays in replies to data requests and in supporting or backup data availability.

CA -- The Commission does not have express authority to examine the books and records of subsidiaries, however the Commission could disallow for ratemaking purposes, any costs which cannot be verified by direct examination. Thus far the Commission has been able to review affiliated transactions to its satisfaction with the reluctant cooperation of company management. The biggest problem the Commission has encountered in this respect is the time it takes the company to respond to requests to examine data and/or to reply to data requests.

CO -- No. The Commission can only disallow costs of this type from rate-making if the utility refuses to allow access. The electric company has been pretty good about allowing access; the telephone companies have not. If the Commission requests this type of information, it can lead to legal discovery in order to obtain it.

CT -- Authority--yes. Cooperative--yes.

DE -- No direct authority.

DC -- Too early to tell if problems will exist.

FL -- (a) No statutory authority.

(b) Yes, company officials have been cooperative.

(c) A problem that the Commisson has encountered is that an affiliate of one of our utilities is involved in partnerships in which they do not have a controlling interest. The other partners are somewhat hesitant to allow the Commission access to the partnership books.

GA -- No, but the commission has been given access to this type of records. No problems have been encountered.

HI -- Statutory authority is provided to examine all transactions and if authority to establish a nonregulated subsidiary is sought this will be a condition of approval similar to our treatment of the holding company.

ID -- No explicit statutory authority.

IL -- Section 8a(2) of the Illinois Public Utilities Act states "The Commission shall have jurisdiction over affiliated interests having transactions, other than ownership of stock and receipt of dividends thereon, with public utilities under the jurisdiction of the Commission, to the extent of access to all accounts and records of such affiliated interests relating to such transactions, including access to accounts and records of joint or general expenses, any portion of which may be applicable to such transactions; and to the extent of authority to require such reports with respect to such transactions to be submitted by such affiliated interests, as the Commission may prescribe."

Company officials have been cooperative in allowing the Commission access to the accounts and records relating to affiliated interest transactions.

KS -- Yes. See KSA 66-1501, in appendix C. There has been only limited opportunities to actually do this.

KY -- The commission does not have explicit authority.

ME -- Yes, the commission has the authority to gain access to books and records. Yes, the company officials have been cooperative. No problems.

MA -- By statue, we have authority to gain access to books of affiliates and subsidiaries to the extent that records deal with transactions with regulated operating utilities generally company officials have been cooperative. With data processing, it is sometimes difficult to extract from the records detailed information.

MI -- Uncertain of authority. We do gain access to records and books with the cooperation of company officials. No problem yet.

MN -- The commission may investigate the affiliate's costs, if necessary, to approve a contract between the utility and its subsidiary. Minn. Stat. §216B.48. The commission has not attempted to gain such access.

MO -- Rate review--access to determine reasonable rates.

MT -- Uncertain.

NV -- The results of the audits performed by independent CPAs are relied on for holding company information. Non-regulated affiliates are checked on a specific transaction basis only. Cooperation has been good and no major problems exist at this time.

NH -- Yes, company officials have been cooperative. No problems have been encountered.

NJ -- The usual provisions of the Board's Orders approving the service contract would require that the service company keep its books and records available at all times for inspection by the Board and shall, at any time, upon request of this Board, furnish any and all information required with respect to the services rendered and the cost to the service company thereof. The cost an expenses of any examination of the records by the Board's Staff or other duly appointed representatives will be borne by the service company. Each year as long as the service contract is in force, a complete statement shall be filed with the Board annually setting forth each item in detail to show separately the charge for service rendered and the basis for calculating that charge. (See the copy of the Orders Docket No. 713-200 and 769-937 abstracted in appendix C.)

In the case of the Holding Company, instead of a special annual statement, a copy of the Annual Report Form U-13-60 (Mutual and Subsidiary Service Companies, filed with the Security Exchange Commission) might be accepted by the Board.

There have been no instances where a subsidiary or a holding company would refuse an access to its books and records.

NY -- Yes, the commission does have authority to gain access to the books and records of subsidiaries.

Generally, company officials have been cooperative. The one problem the commission has encountered is poor recordkeeping.

NC -- The Commission has authority to inspect the books and records of affiliates and subsidiaries of electric utilities and other regulated utilities under G.S. 62-51 (see answer to question number 14). The regulated utilities have been cooperative when the Commission exercised this authority .

ND -- Yes. Officials have been cooperative. Existing problems are an unwillingness to real proprietory information which could be used by a competitor.

OH -- The commission has in the past requested access to the books of subsidiaries and parent companies of the utilities we regulate. We have not met with company resistance.

OR -- Yes, they are generally cooperative.

PA -- We do not have jurisdiction over holding companies or affiliates, therefore we have no authority to gain access to their books by the direct means of ordering the holding company or affiliate to provide requested information.

However, we can gain the necessary information, if it is of probative value in setting rates for a jurisdictional utility, by directing the jurisdictional utility to provide the information. Failure to provide could result in a determination that the burden of proof has not been satisfied and a revenue adjustment would normally follow.

There are provisions in our Public Utility Code, 66 Pa. C.S. §2101-07, which require the jurisdictional utility to provide records or data of an affiliate as a condition to commission approval of contracts with affiliates.

SC -- Yes. This authority is by order and companies have been very explicit in their acceptance of this authority.

SD -- Don't know.

TX -- The Commission has jurisdiction over affiliates interests to the extent of access to all accounts and records relating to transactions between the affiliate and the regulated utility including the allocation of joint costs. Jurisdiction is provided for in PURA, Article IX, Section 67. The companies have generally been cooperative.

UT -- The commission has the authority to gain access to books and records of the subsidiary. No attempt has been yet made to exercise this authority.

WA -- 1st question--yes. 2nd question--no problem, in that a strong affiliated interest statue requires the utility to support the reasonableness of any payments to an affiliated interest using the cost the affiliate incurs to provide the goods or services.

WV -- No, however, we have in the past been allowed to examine such records. Of course, the Company realizes that costs would have to be reviewed to determine whether or not they're reasonable. If access to determine that is not allowed, then Staff would recommend disallowance of such costs. We have not run into serious problems with our electric companies in this regard.

LA, MS, NM, TN -- No answer.

23. Does your commission have the authority to order divestiture of electric utility subsidiaries or affiliates from the parent company? If so, under what circumstances?

AL -- The process of divestiture of a subsidiary from a parent has never been pursued at this Commission. However, should the Commission not ultimately have the right of divestiture, adjustment to utility operations would be made accordingly during rate proceedings.

AZ -- No.
AR -- No.
CA -- No
CT -- No.

DE -- Never tested.

DC -- No.
FL -- No.
GA -- No.

HI -- Not applicable due to the "non-experience" factor, it would appear that the facts and circumstances in each case would dictate the sanctions.

ID -- No.

IL -- To the best of our knowledge, there have been no instances in which the commission has attempted to order divestiture of electric utility subsidiaries or affiliates.

KS -- No.

KY -- No explicit authority.

ME -- Yes, after full due process.

MA -- This has never happened, but we probably do have authority if they are established by an operating utility company and not a holding company.

MI -- Uncertain.

MN -- Probably not.

MO -- No specific authority exists. If the need arose, it would be looked into.

MT -- Uncertain.

NV -- No.

NH -- Yes, if a complaint is submitted or if the commission finds that the contract appears not to be in the public interest.

NJ -- No.

NY -- No specific authority.

NC -- I believe the Commission could revoke an electric utility's franchise if the utility refused to divest itself of a subsidiary or affiliate if it were shown that the operations of the affiliate or subsidiary were preventing the regulated utility from performing its franchised duties in a satisfactory manner. Such Commission action would be possible only after formal hearings that permitted all interested parties to be heard.

ND -- No.

OH -- The commission has never considered the divestiture of a utility it regulates. It is our position, however, that R.C. 4901.02 gives the commission broad authority in carrying out the purposes of R.C. Title 49.

OR -- No.

PA -- There is no express authority to order divestiture. If we have the implied power, it would probably be under the circumstance that divestiture was required to assure continued financial health of jurisdictional utility and that the ability to provide safe and adequate service could not be maintained absent divestiture.

SC -- No.
SD -- No.

UT -- The commission has authority to order divestiture of the subsidiary if the utility's financial viability is in question.

WA -- No direct authority. If major problems arose the utilities are aware proposed legislation could be introduced in the legislature and hopefully passed to correct the problems.

WV -- No.

CO, LA, MS, NM, TN, TX -- No answer or not applicable.

VIII. Question 24 asks about the costs to a commission of regulating electric utility subsidiaries and affiliates.

24. Approximately how much staff time and expense is devoted to regulation of electric utility subsidiaries and affiliates? Has the regulation of electric utility subsidiaries and affiliates required the hiring of new staff?

AL -- Very little time is devoted to this regulation because of the limited resources. New hiring are placed in other areas considerd more important.

AZ -- None.

AR -- Impossible to determine time. No new staff as a direct result of subsidiaries.

CA -- Since the review of affiliated transactions has been a routine in our regulation of electric utilities for many years, it is difficult to set out the percentage devoted to that procedure as at times it has been minimal and at other times quite extensive. An estimation would be 1 man-year for each major electric utility (3). The commission anticipates that in the near future additional staff will be required a electric utilities begin to diversify.

CO -- Not an amount that can be measured, it is part of the audit process. It has not required hearing new staff.

CT -- Minimal.

DE -- None

GA -- Almost none. No new hires.

HI -- Not applicable due to a lack of experience.

ID -- The additional cost is generally minimal and inseparable. Review is conducted as an integral part of the general review of a regulated utility operation.

IL -- Specific information is not available. However, substantial staff time is devoted to affiliated interest transactions. Regulation of electric utility subsidiaries and affiliates is divided among several staff members so that regulation of electric utility subsidiaries and affiliates would not necessarily require the hiring of additional staff.

KS -- Limited staff time has been devoted to this pertaining to electric utilities.

KY -- Very little, if any.

ME -- Not much time. Our entire experience has been focussed on telephone.

MI -- Data not available.

MN -- Less than 5 percent. No new hires.

MO -- Only minor audit time. No new employee specifically for this.

MT -- Uncertain.

NV -- Staff time is utilized during the regular audit function prior to rate case hearings. No new staff has been required for the specific purpose of regulating subsidiaries and affiliates.

NH -- Five percent. No new staff has been hired.

NJ -- There are no studies available in this matter and no staff was hired or assigned specifically for this purpose only.

NY -- Minor. No.

NC -- There have been no separate costs kept for these activities. An estimate would be that the equivalent of one full-time professional trained as a financial analyst, economist, engineer, or accountant with the assistance of one clerical person could handle these activities. No new staff has been hired solely to perform the duties associated with this type of regulation.

ND -- No.

OH -- Underterminable. No.

OR -- 1 man-year per year. We have not hired new staff, but we have changed job responsibilities. One analyst now devotes 100 percent of his time to this issue.

PA -- Very limited staff time is devoted to regulation of electric utility subsidiaries and affiliates. As previously stated, we review affiliated interest contracts and a very limited time is devoted to affiliate interest charges in rate proceedings.

SC -- The commission has not attempted to quantify the amount of time or expense associated with this specific aspect of regulation. The commission has not hired any new employees to monitor transactions between companies.

TX -- Approximately three percent of staff time is devoted to review of affiliates because of the relatively small number of such related parties. Staff has not been increased directly due to the existence of related parties.

UT -- No experience at this time. The only staff time expended was in a hearing to set up the subsidiary.

WA -- Within the Finance Section one of its duties is to analyze, recommend course of action, and draft orders dealing with contracts or arrangements between utilities and their affiliated interests. Such authority has been part of public service law since 1933. Staff already in place since the 1940s.

For rate cases, expert testimony is always required in dealing with affiliated interest costs and charges. This issue could constitute up to 20 percent of the rate case staff time and direct Commission costs in the case.

The staff time for dealing with rate relief requests by the utility in the area of affiliated interests is part of the normal staff duties.

WV -- Unknown.

FL, LA, MS, NM, TN -- No answer or not applicable.

APPENDIX C

SELECTED STATE STATUTES, REGULATIONS, AND ORDERS

This appendix contains references to and short abstracts of selected state statutes, regulations, and orders that deal with state commission regulation of electric utilities with subsidiaries and affiliates. Most of the materials in this appendix were furnished by the staffs of the state commissions along with their responses to the NRRI survey discussed in Chapter 3 of this report. Some additional materials were gathered by the authors during the course of their research and these are also included. As noted above, this appendix discusses selected laws, regulations, and orders. The authors chose those materials that they felt were good examples of alternatives for possible consideration by state commissions.

Connecticut--In Re the Southern Connecticut Gas Company, Decision and Order No. 770-828 (Conn PUCA, Dec. 13, 1978).

This case deals with an exempt gas holding company, but it does provide some ideas on what a commission could do to handle an exempt electric holding company. In this case the Connecticut PUCA required a gas holding company to submit to numerous conditions before it would allow the company to be established. These conditions included requiring the holding company to acquire and to maintain an exemption from PUHCA registration, to incorporate in Connecticut, and to submit S.E.C. and other reports to the PUCA. Another condition was that the PUCA be given the right to inspect the holding company's books and records. Affiliate transactions were to be priced by the appropriate regulatory agency or (if the gas purchased in the transaction has been deregulated under the Natural Gas Policy Act) set at the wellhead market price plus cost of transportation. The order provides that no revenue, income, expense, loss, asset, or liability of an affiliate will be attributed to the utility, except for intercorporate charges attributable to the utility under either service agreements or the tax allocation agreement. The PUCA examines these agreements. The order also provided that neither the holding company nor any of its subsidiaries could create new subsidiaries or lines of business that are not functionally related to the utility, without prior PUCA approval. Also the holding company may not, without prior PUCA approval, invest in any nonutility subsidiary if such investment would cause the aggregate amount of nonutility investment to exceed 20 percent of the utility company's shareholders' equity. The PUCA also set limitations on nonutility subsidiaries' indebtedness and the pay-out of dividends to subsidiaries. The PUCA reserved the power to require the dissolution of part or all of the holding company if it has reasonable cause to believe that the continued operation of the holding company is not in the interest of the utility's customers.

Hawaii--In the Matter of the Application of Hawaiian Electric Company, Inc. for Approval of the Merger of New HECO, Inc. into it and Related Matters and the Application of Hawaiian Electric Industries, Inc. to Own All of the Issued and Outstanding Common Stock of Hawaiian Electric Company, Inc., Docket No. 4337, Order No. 7256 (Hawaii P.U.C., September 29, 1982).

This order allowed, subject to certain conditions, the Hawaiian Electric Industries to merge and form a holding company. The order gave the Hawaii Public Utilities Commission (PUC) the right to investigate any matter, activity, or transaction between the utility and its parent holding company. The order also allowed the PUC and the Hawaii Department of Commerce and Consumer Affairs, Public Utilities Division (consumer advocate) access to and the right to inspect the books and records of the holding company and its subsidiary. The holding company must provide the Hawaii PUC and the consumer advocate with financial records together with an explanation of the nature of intercompany transactions and the basis of any allocations made. The holding company's officers, directors, employees, and agents must appear to testify before the Hawaii PUC when requested to do so. All information relating to the assets, liabilities, income and expenses of the holding company are to be considered confidential, except when relevant to a Hawaii PUC or court proceeding. As noted earlier, the Hawaii PUC can investigate any affiliate transaction. The Hawaii PUC can also review intercompany charges and common expenses, including those related to personnel sharing, common expenses for facilities, common expenses for outside services, and construction costs. The order provides limitations on loans between the utility and the holding company. The order noted that the holding company was undertaking the corporate reorganization so that the utility (Hawaiian Electric Company) could be more clearly delineated from future diversified activities of a nonutility nature. The order also provided that utility will not pay cash dividends in excess of 80 percent of its earnings. The Hawaii PUC will retain its authority over the utility's issuance of securities, and the utility will not redeem its common stock without prior Commission approval. The holding company will not divest itself of the utility's stock without prior Commission approval. But the Hawaii PUC may order the holding company to divest the utility if either the holding company or utility fails to comply with the order.

Idaho--In the Matter of the Application of Utah Power & Light Company for (1) an Order Disclaiming Jurisdiction, or (2) in the Alternative an Order Authorizing it to Form and Finance a Wholly-Owned Subsidiary, Order No. 18784, Case No. U-1009-4, (ID. P.U.C., April 4, 1984). This order concluded that the Idaho Public Utilities Commission did not have jurisdiction to regulate the formation of a non-utility subsidiary, but that the Commission had the authority to require some safeguards to be implemented to ensure that the formation of a subsidiary did not have a detrimental impact on the company's regulated utility operations. The order required that (1) all subsidiary activities must be segregated from utility activities through a separate corporation with separate office facilities, (2) any services, material, or contracts between the subsidiary and utility (excepting cogeneration contracts) will be treated as affiliate transactions subject to Commission review, and (3) any use of the utility's operating management, funds, or credit shall be subject to Commission review. In order to implement these safeguards, the order required the utility to make available, upon request, the books and records of the subsidiary.

Illinois--Illinois Public Utilities Act, Sections 8a(2), 12, 27(g), 27(h).
The Act provides that a utility must file for Illinois Commerce Commission approval to establish any business or enterprise not essentially and directly connected with, or a proper and necessary department or division of the public utility. The request for Commission approval may come in a securities proceeding. The Commission may require that the books and records of the non-utility subsidiary be kept separately and it is authorized to examine and inspect those books and records. The Act empowers the Commission to prescribe the apportionment of capitalization, earnings, debts, and expenses. The Act gives the Commission jurisdiction over all affiliate transactions and access to accounts and records that relate to the transactions. The Commission may require that reports be submitted with respect to such transactions.

Kansas--Kansas Statutes, Sections 66-1401, 66-1402, and 66-1403.
Section 66-1401 provides the Kansas State Corporation Commission with jurisdiction over holding companies, and over affiliate transactions. This section also empowers the Commission to gain access to all accounts and records relating to affiliate transactions. The Commission is authorized to require a holding company, an affiliate, or other affiliated interest to submit reports as the Commission may prescribe. Section 66-1402 provides that contracts with holding companies, affiliates, or other affiliated interests must first be filed with the Commission to be effective. The Commission is authorized to disapprove the contract if it finds after investigation and hearing that the contract is not in the public interest. Section 66-1403 requires a holding company or affiliate to provide an itemized statement detailing the actual cost for services or items rendered before

the utility will be allowed to include the cost of the affiliate transaction in rates.

Maine--H.P. 2267-L.D. 2114, An Act to Provide that Corporate Reoganizations Affecting Public Utilities Be Subject to Approval by the Public Utilities Commission. 35 Me. Rev. Stat. Ann. §104(1)-(4)

The Act provides that a public utility holding company is an affiliated interest, and that all public utility reorganizations are subject to commission approval. The Commission will only approve a reorganization if it finds that the reorganization is consistent with the interests of the utility's ratepayers and investors. In granting approval, the Commission may impose terms, conditions, or requirements which it deems necessary to protect the interests of the ratepayers. These conditions can include empowering the Commission (1) to have reasonable access to books, records, documents, and other information relating to the utility or its affiliates, (2) to be able to detect, identify, review, and approve or disapprove all affiliate transactions, (3) to assure that the utility's ability to attract capital on reasonable terms is not impaired, (4) to assure that the ability of the utility to provide safe, reasonable, and adequate service is not impaired, (5) to assure that the utility continues to be subject to the applicable laws, principles, and rules governing the regulation of public utilities, (6) to assure that the utility's credit is not impaired or adversely affected, (7) to assure that reasonable limits are imposed on the total level of investment in nonutility businesses, (8) to assure that neither ratepayers nor investors are adversely affected by the reorganization, and (9) to take whatever remedial steps are necessary to protect the interests of the utility, ratepayers, or investors, including ordering the holding company to divest the utility. The Act does not provide the Commission with the authority to approve or disapprove the nature of a nonutility business.

Massachusetts--In Re Boston Edison Company and BECo Electric Company, D.P.U. Order 850 (Mass. D.P.U., Feb. 9, 1983).

This was a petition of the Boston Edison Company and the BECo Electric Company for approval by the Massachusetts Department of Public Utilities of a merger that would have resulted in the formation of a holding company. The petition was denied because the Boston Edison Company failed to demonstrate that the proposed merger was "consistent with the public interest," the applicable standard under section 96 of chapter 164 of the Massachusetts General Laws. The Department stated that it would have found such a proposal to be consistent with the public interest if, upon consideration of all of the plan's significant aspects viewed as a whole, the public interest was at least as well serve by approval of the proposal as by its denial. The D.P.U. denied the company's petition because the company failed to rebut potential dangers of a holding company structure that were identified by intervenors. These potential dangers included a tangible loss of the utility's dividend reinvestment and employee stock ownership plans, a drain on the utility's capital, management distraction or overextension, and a possible increase in the cost of capital and exposure of ratepayers to higher risks. The Department was concerned that the retained earnings of the utility might be used to provide the capital to fund new nonutility affiliates, while replacement capital for the divested funds was deferred and/or more expensive. This drain on utility funds might continue if a new enterprise had start-up losses. The regulators opined that if a new enterprise became more successful than the utility, then there would be an incentive for the holding company to transfer capital from the lower-earning utility activities to the affiliates earning a higher return. The order noted that unsuccessful diversification would ultimately lead to a higher cost of capital to the utility. The regulators stated that the company failed to say how it would embark on new risk-taking ventures and consequently failed to assess how those ventures would affect the utility. The company's claims of benefits that may be expected from the reorganization were discounted because those claims were based primarily on the company's beliefs about future effects or conditions and they were presented without a factual foundation or other indicia of reliability. In other words, the opinions entered into testimony were not accompanied by supporting evidence.

In Re Petition at Boston Edison Company, D.P.U. Order 1281 (Mass. D.P.U., Dec. 23, 1982).

This was a petition of the Boston Edison Company for approval by the Massachusetts Department of Public Utilities of the company's entering into, executing, and delivering of a credit agreement and a note and security agreement. The agreements and note provided for the possible formation of a wholly-owned, single purpose financing subsidiary, the acquisition by the BECo Fuel Company, Inc. (an existing fuel subsidiary) of a security interest in nuclear material owned and to be acquired by the Company, and the guaranty by the utility of up to $50 million in commercial paper to be issued by the newly formed subsidiary or by the BECo Fuel Company. Under the petition, the $50 million would be used to repay existing indebtedness and for general corporate purposes, including nuclear material and capital expenditures. The Department found that (1) the formation of a single-purpose financing subsidiary or the additional use of the BECo Fuel Company for the purpose of carrying out the financing arrangements described in the petition; (2) the entering into, executing, and delivery of the credit agreement, note, and security agreement; and (3) the guaranty by the utility of up to $50 million in commercial paper to be issued by a newly formed financing or an existing fuel subsidiary are consistent with the public interest. The Department limited the use of $50 million to repayment of existing utility indebtedness under the Prulease, Inc. Agreement, and for corporate working capital expenditures. The D.P.U. also conditioned its findings on the fuel subsidiary's maintenance of proper records, and stated that its approval of these financings did not constitute a determination of their propriety for rate-making purposes.

Minnesota--In the Matter of the Request of Northern States Power Company for Approval of a Cost Allocation Method for Dividing Joint Facility Costs of Steam Produced at its High Bridge Plant, Docket No. E-002/CI-82-523, Order Approving Stipulation (Minn. PUC, March 23, 1983).

The Northern States Power Company petitioned for approval of a proposed incremental cost allocation formula by which the joint facilities' costs of steam produced at Northern States Power's High Bridge plant would be shared between the company and its newly formed, wholly-owned steam sale subsidiary, NORENCO. The incremental cost allocation approach would result in NORENCO paying only for the conversion costs and additional operation and maintenance costs of selling steam. The utility contended that, under the incremental costing approach, NORENCO would pay for all additional expenses incurred by the utility because of the subsidiary's steam sales. The parties to the case stipulated that an incremental costing approach was appropriate to use as the basis for allocating costs associated with nonregulated projects in this case, and that the incremental costing method insulated utility ratepayers as much as possible from the costs and risks of nonregulated projects. The parties also stipulated that there would be no user's fee nor any other amount in excess of identifiable incremental costs charged to NORENCO--although a users fee of up to 5 percent of the nonfuel, noncapital expenses paid by NORENCO may be imposed in future projects. The stipulation also provided that thermal energy and administrative services agreements executed between the utility and NORENCO would be subject to the Commission's affiliated interest statute. The Commission found that the stipulations entered into by the parties provided a reasonable resolution of the issues. Specifically, the regulators approved the proposed incremental cost allocation method because ratepayers were not likely to be made worse off as a result of the diversification project. However, the P.U.C. held that, in future diversification cases, utilities must present convincing evidence that ratepayers will not be hurt by the proposed projects. If there is any uncertainty in that regard (as is likely), the Commission will require that any questionable cost allocation be weighted in favor of the ratepayer to assure that rates will not increase as a result of the project. The Commission will review the specific facts in the future on a case-by-case basis to determine what is reasonable.

New Jersey--New Jersey Revised Statutes, Section 48:3-7.1

This provision of the New Jersey Revised Statutes states that no affiliated interest contract, involving management, advisory, construction, or engineering services that (directly or indirectly) involves $25,000, is valid until approved by the New Jersey Board of Public Utilities. No contract will be disapproved unless a hearing is held after due notice. Contracts will be approved, unless the contract violates the law, the price or compensation provided for in the contract exceeds the "fair" price or compensation, or the contract is contrary to public interest.

In the Matter of the Petition of Jersey Central Light Company and New Jersey Power & Light Company for Approval of a Second Amendment to a Contract with Saxton Nuclear Experimental Corporation, Et Al., Docket No. 694-167 (NJDPU, June 19, 1969).

The New Jersey Department of Public Utilities approved a contract which allowed the petitioning utilities, affiliates of the General Public Utilities Corporation, to extend their participation in the operation of an experimental nuclear reactor. The Board made one caveat and laid out one condition on its approval of the project. The caveat was that the decision would not bind the Board in future petitions or proceedings with respect to the petitioners. The condition set out was that, upon termination of the Saxton Nuclear Experimental Corporation project, the disposition of the projects assets would be subject to approval by the Board.

In the Matter of the Petition of Jersey Central Power & Light Company and New Jersey Power & Light Company for Approval of an Agreement with GPU Service Corporation, Docket No. 713-200 (NJBPU, April 28, 1971).

This case involved Jersey Central Power & Light Company and New Jersey Power & Light Company, wholly-owned subsidiaries of the General Public Utilities Corporation, and the GPU Service Company, also an affiliate company and a wholly-owned subsidiary of General Public Utilities Corporation. In the order the NJBPU found that the agreement for services was not unreasonable, not contrary to the public interest, and in accordance with the law. The Board approved the petition with one caveat and one condition. The caveat was that this order would not affect or limit the authority of the Board in any proceeding affecting the petitioners. The condition was that the GPU Corporation must file annually with the Board a complete statement setting forth each item of expense and the allocation and distribution of costs relating to the services provided by GPU Service Corporation both to the petitioners and *in toto*.

In the Matter of the Petition of Rockland Electric Company for Approval of an Agreement Between Orange and Rockland Utilities, Inc. and Rockland Electric Company, Docket No. 769-937 (NJBPU,(---------).

This case involved the Rockland Electric Company, a wholly-owned subsidiary of Orange and Rockland, Utilities, Inc. The Rockland Electric Company transmited and distributed electricity to customers in northern New Jersey, but had no generating facilities of its own nor any personnel other than corporate officers. It sought approval of a service agreement between itself and Orange and Rockland Utilities, Inc. to cover the allocation of charges for the operation and maintenance of transmission and distribution equipment, line construction, sales promotion, billing and collecting, accounting, engineering, and administrative services, as well as depreciation, tax, and insurance expenses. The proposed service agreement provided that charges would be made on a direct basis where practical. Where impractical, the charges for joint operating costs would be apportioned on the basis of a revenue ratio for general and administrative expense items, and on a customer ratio for all other expense items. The NJDPU board approved the proposed service agreement because it was reasonable, not contrary to the public interest, and in accordance with the law. However, the Board set out a caveat and three conditions to its approval. The caveat was that the approval of the service contract did not affect or limit the authority of the Board in any future proceeding concerning rates or any other matter. The three conditions were that (1) the Orange and Rockland Utilities, Inc. agreed to keep its books and records available for inspection to the Board and to furnish to the Board, upon request, any information required with respect to the services that it rendeded and the costs of those services; (2) that the costs and expenses of examining the records would be borne by Orange and Rockland Utilities; and (3) that Rockland Electric Company would file an annual complete statement setting forth each item of expense in sufficient detail to show the charge for the service rendered and the basis for calculating that charge.

New Mexico--In the Matter of the Adoption of Proposed Rules Regarding Class I and Class II Utility Transactions Under Chapter 109, Laws of 1982 (General Order No. 39), Case No. 1759, Order (MNPSC, November 30, 1982).

General Order No. 39 sets forth the NMPSC's policy and requirements concerning certain transactions by electric and gas utilities under the Commission's jurisdiction. There are two classes of transactions covered. The first class, a "Class I transaction," is an affiliate transaction either by holding company, subsidiary, or affiliate to the public utility or by the utility to its holding company, subsidiary, or its affiliate. The second class of transaction, "Class II transactions," concerns the formation of a holding company, or utility subsidiary, or the divestiture of a corporate subsidiary of a public utility. Class II transactions also cover several other types of financial arrangements by which a public utility would gain ownership interest or acquire or guarantee securities of another person.

General Order No. 39 requires that a public utility which enters into an agreement or arrangement under which a Class I (affiliate) transaction would occur is required to give written notice to the Commission within five days after the agreement or arrangement is entered into. The notice must not only set out the terms and details of the arrangement, but must also include a discussion of whether the utility could, or attempted to, obtain the goods and services at a lower price, a statement of the purpose of the transaction explaining how it benefits the utility or its ratepayers or both, and (if the utility is selling goods, services, or property interests) a discussion of whether the utility could obtain a better price. Notification is not necessary for affiliate transactions that consist only of the provision of normal utility services to an affiliate under tariffs on file at the Commission. General Order No. 39 also requires that every six months each utility engaged in an affiliate transaction during the preceding six months must provide a statement showing the moneys, securities, or other items of value paid or transferred either by the utility to the affiliate or by the affiliate to the utility. The statement must show the dollar amount of each affiliate transaction by account (using the Uniform System of Accounts) and by types of goods or services provided, the quantity, and the price paid or received. The order provides that there is no presumption that an affiliate transaction is reasonable and that the utility has the burden of proof that all affiliate transaction costs and contract conditions are reasonable.

General Order No. 39 states that no utility may engage in a Class II transaction without first obtaining from the Commission written approval of a general diversification plan. When filing for approval of a general diversification plan, the utility must provide notice of the filing to each intervenor in its proceeding rate case and to the state Attorney General. The general diversification plan is very detailed. It must include (1) the name, home office address, and chief executive officer of each affiliate, subsidiary, holding company, or person that is the subject of the Class II transaction; (2) a statement of goals and effects upon the utility operation of the Class II transaction, including an analysis of benefits, costs, and risks as well as tax effects; (3) the type of corporate structure to be used; (4) the means of implementing the corporate structure, e.g., acquisitions, transfers, or conversions of securities; (5) the anticipated capital structure for the utility, its affiliates and consolidated entity of the next five years; (6) the contemplated annual and cumulative investment in each affiliated interest for the next five years, expressed both in dollars and as a percentage of projected net utility plant, together with an explanation as to why this level of investment is reasonable and will not increase the utility's risk; (7) an explanation of how the affiliate(s) will be financed, by whom, and the types and amounts of securities to be used; (8) an explanation of how the utility's capital structure and cost of capital (including the cost of future capital) will be affected; (9) an explanation of how the utility can assure that adequate capital is available for the construction of necessary new plant at a cost no greater than that available if the Class II transaction had not taken place; (10) an explanation of how ratepayers will be protected and insulated from risks, costs, or other material adverse effects unattributable to the Class II transaction; (11) (if the utility intends to divest a corporate subsidiary) an explanation of the reason for the divestiture, how it will be accomplished, how it will affect the utility's cost of capital and adequacy of service during the next ten years, whether there has been a ratepayer contribution to the subsidiary, the anticipated proceeds to the utility, and the extent (if any) to which the utility intends to share in the proceeds or otherwise benefit from the divestiture; and (12) any other information necessary that will allow the Commission to make its findings. No affiliate or holding company may divest itself or spin-off a public utility without prior written approval of the Commission. Approval will be given only after an investigation and a showing that the divestiture or spin-off is in the public interest. General Order No. 39 states that approval of a general diversification plan is in the public interest if the Commission finds (1) that the level of investment appears reasonable; (2) that the utility's ability to provide reasonable and proper service at fair, just, and reasonable rates will not be materially adversely affected by Class II transactions; (3) that the books and records of the utility will be kept separate from those of nonregulated businesses and in accordance with the Uniform System of Accounts; (4) that the Commission and its staff will have access to the books, records, accounts or documents of the holding company, affiliate, or subsidiary, (5) that the supervision and regulation of the utility will not be obstructed, hindered, diminished, impaired, or unduly complicated; (6) that, if a holding company is formed, the utility will not pay excessive dividends to the holding company and the holding company will not take any action that will have a material adverse effect on the utility's ability to provide adequate service at fair, just, and reasonable rates; (7) that the utility will not, without prior Commission approval, loan its funds or securities or transfer similar assets to any affiliated company, nor purchase the debt instruments, nor guarantee or assume liabilities of an affiliated company; (8) that all applicable state and federal laws have been complied with; (9) that, when required by the Commission, the utility will have an allocation study performed at its own expense by a consulting firm chosen by and under the direction of the Commission; and (10) that, when required by the Commission, the utility will have a management audit performed at its own expense by a consulting firm chosen by and under the direction of the

Commission. The management audit will determine whether there are any adverse effects because of the Class II transactions. The Commission may require modification of a general diversification plan and may attach conditions to its approval of the plan to make the plan consistent with the public interest or to avoid material adverse effects on the utility's ability to provide adequate service at fair, just, and reasonable rates. Commission approval of a general diversification plan does not limit or preclude the Commission from subsequent actions to protect the ratepayer. A utility must also provide the Commission with any petition, declaration, or other legal document filed with a court, the United States S.E.C., or other state or federal agency.

After approval of a utility's general diversification plan (or after the more streamlined diversification summary by those utilities with already existing affiliates), the utility must provide the Commission with (a) a concurrent notice of all new or expanded lines of business entered into by the utility or its affiliate and any transfer of rights, obligations, or assets between the utility and the affiliate; and (b) an annual report that includes: (1) an explanation and description of all the affiliates, their relationship to each other, and to the utility, and the types of business they are involved in; (2) the affiliates' home office addresses, the total utility investment in each affiliate; (3) any joint facilities or personnel together with an explanation of their functions and how they are allocated; (4) all contracts and agreements required to implement or to continue the Class II transaction; (5) a summary and explanation of any transactions or agreements between the utility and its affiliates, corporate subsidiaries, and holding companies; (6) the allocation factors used, the dollar amounts involved and an explanation of how the allocation factors are computed, why that methodology is appropriate, and why the allocation is required; (7) an explanation and justification of changes to any part of the utility's general diversification plan or representation concerning the plan made to the Commission; (8) the immediate and projected long-term impact of the Class II transactions on the capital structure of the utility; (9) an identification and complete explanation of the method by which any Class II transaction (or any related action that has a utility accounting impact) is or will be accounted for by the utility; (10) the names of the officers and managers of the utility and its affiliates; (11) the most recent balance sheet and income statement that the utility from each of its affiliates, subsidiaries, and the holding company; (12) the effect of the Class II transaction (or related actions) on the financial performance of the utility and the utility's ability to provide adequate service at fair, just, and reasonable rates; (13) all costs and fees related to the Class II transaction and any necessary corporate restructuring; (14) a year-by-year annual five year projection using pro forma financial statements showing the effects of the utility's decision to enter into the Class II transaction compared with a decision not to enter into the Class II transaction and showing the expected impact of the Class II transaction on rates and other matters related to the public interest; (15) the end-of-year consolidated capital structure (utility, together with affiliates); (16) an explanation of how the utility's capital structure, cost of capital, and ability to raise capital have been impacted by Class II transactions and their resulting effect; (17) the amount of dollars transferred between the utility and each affiliate during the annual period and the purpose of each transfer; (18) an explanation of how the utility's taxes and their calculation have been impacted, both on a stand-alone and consolidated basis, by the Class II transactions; (19) a five year, year-by-year projection of new utility capital requirements categorized and identified, to the extent feasible, together with the projected sources and amounts of capital that will be used to meet these requirements; and (20) an explanation of any impacts on new utility capital requirements from Class II transactions and their resulting effects.

General Order No. 39 states that there is no presumption that a utility's allocation method is reasonable, and that the burden of proof is on the utility in a rate case or other proceeding to justify its method of allocating expenses, the factors used, and the amounts allocated. The General Order also requires the utility to bear a burden of proof that its rates, costs, and service have not been materially and adversely affected by any Class II transactions or its resulting effect and that the utility has not subsidized its affiliates. Costs here includes the cost of capital.

North Carolina--General Statutes of North Carolina, §62-51.

This statutory provision authorizes the Commission, its staff, and public staff to inspect the books and records of corporations affiliated with public utilities under the jurisdiction of the Commission. These include a parent holding company and the subsidiaries of a holding company. The authorization to inspect books and records extends to all accounts, agreements, and transactions between North Carolina utilities and their affiliates where such records relate directly or indirectly to the provision of intrastate service. The right to inspect books and records applies to documents located both within and outside of North Carolina. If any affiliated corporation refuses to permit inspection of its books, the Commission is empowered to order the North Carolina utility to show cause why it should not secure the books and records from its affiliated corporation, or why its franchise to operate as a public utility in North Carolina should not be cancelled.

Oregon--Pacific Northwest Bell Telephone Company v. W. Sabin, 534 P. 2d. 984 (Or. Ct. App., 1975).

Although this case concerns a telephone company and its affiliates, it demonstrates germane principles of law that could flow over and directly affect the regulation of electric utilities with subsidiaries in Oregon. This case stands for two propositions. First, that prior approvals of contracts between a public utility and its affiliate do not have the effect of creating a regulatory estoppel that prevents subsequent scrutiny, for the purpose of calculating rates, of the reasonableness of the expenditures. Second, that where, as in Oregon, a regulatory agent has been granted broad legislative authority he is not obligated to employ any single formula or combination of formulas to determine what are just and reasonable rates. Where a utility purchases the bulk of some item from an affiliate and that affiliate enjoys a unique position of market power which renders a comparison of its prices and profits with other peripheral suppliers inadequate, the Commissioner can use the failure by the utility to further justify the reasonableness of its payments to the affiliate as the basis for disallowing from the utility's operating expenses those portions of the utility's payments to its affiliate which represent a return to the affiliate greater than that allowed to the utility itself.

Oregon Revised Statutes, §§757.490 and 757.495

Section 757.490 of the Oregon Revised Statutes concerns approval of contracts between a utility and its subsidiaries. It requires that before a utility enters into a contract with a subsidiary corporation that the utility owns a majority of or controls directly or indirectly, the proposed contract must be filed with the Commissioner for his investigation and approval. When a proposed contract is filed with the Commissioner, he will promptly investigate. In doing so, the Commissioner and his staff must be given free access to all the utility's and subsidiaries books, accounts, documents, data, and records, which the Commissioner may deem material to the investigation. A failure or refusal of either party to provide free access is prima facie evidence that the contract is unfair, unreasonable, and contrary to the public interest, and is sufficient to justify such a determination by the Commissioner.

Section 757.495 concerns contracts involving utilities and persons with affiliated interests. It states that a utility can not make or contract to make any payment to any person or corporation having an affiliated interest for services, nor enter associated charges on its books to be recognized as an operating or capital expenditure, until it has been submitted to the Commissioner and the propriety and reasonableness of the payment or contract has been approved by him. The section also states that a utility can not enter into any contract, with any person or corporation having an affiliated interest, that relates to the construction, operation, maintenance, leasing, use or purchase of property, of materials, or of supplies to be recognized as an operating expense or capital expenditure, unless the contract has been submitted to and approved by the Commissioner. When a proposed contract is submitted to the Commissioner, he will promptly examine and investigate it. If, after investigation of either type of contract, the utility-subsidiary or utility-affiliate, the Commissioner determines that it is fair, reasonable, and not contrary to the public interest, he will approve the contract and it becomes legally recognized. If, on the other hand, he finds that the contract is not fair and reasonable in all its terms or is contrary to the public interest, he will disapprove it, and it will be unlawful to recognize the contract. The section also states that no utility can issue notes, loan its funds, or give credit to any affiliated interest without the approval of the Commissioner.

Oregon Administrative Rules, Chapter 860, Division 27 - Public Utility Commissioner, Section 860-27-040, Applications for Approval of Transactions Between Affiliated Interests

This portion of the Oregon Administrative Rules sets out the filing requirements that apply to public utilities seeking approval of contracts between themselves and their subsidiaries or affiliates, under Oregon Revised Statutes Sections 757.490 and 757.495, respectively. The filing requirements include a detailed statement about the type of affiliate (when applicable); the names of the officers of the affiliate; the type of contract; the reasons, in detail, relied on by the utility for entering into the proposed transaction and the benefits, if any, to be derived by the ratepayers and the public; and a statement of the facts relied upon by the utility to show that the proposed transaction is in the public interest. All filings also require several exhibits that provide further detail about the corporate structure and finances of the utility and its affiliate or subsidiary, and other existing or planned affiliate transactions between the two entities. Additional special exhibits are required to be filed for certain types of applications. If the application is for the approval of either payments or a contract to make payments for advice, auditing, accounting, sponsoring, engineering, managing, operating, financial, legal, or other services, then four additional exhibits are to be filed. They are (1) a statement of the salaries paid by the affiliated interest to its officers and employees who will render the services, (2) a statement of the method to be used in computing the payment for the services, (3) a statement showing in detail the costs to the affiliated interest of rendering the service to the applicant and the method used to determine the costs, and (4) a statement showing the estimated amount to be paid annually for the services and the accounts to which the payments are to be charged on the utility's books. If the application is for approval of a contract or agreement for the construction of public utility property for the utility, then one additional exhibit is required. That exhibit must contain a complete description of the property to be constructed for the utility, and copies of maps, plans and detailed estimates set out in a manner so that they can be checked by the Commissioner's engineers. If the application is for the approval of a contract or agreement for the operation, maintenance, rental, or leasing of the applicant's property, then three additional exhibits are required. They are (1) a general description of the property to be operated, maintained, rented, leased, or used; (2) the original cost of the property and the related accrued depreciation or amortization reserves; and (3) the consideration to be paid for the operation, maintenance, rental, or leasing or use of the utility's property and the exact method of determining the consideration. If the application is for the approval of a contract or agreement for the purchase of property, material, or supplies by the utility, then two additional exhibits are required. The first of these two exhibits is a statement containing a general description of the property to be purchased together with the value of the property and its estimated purchase or contract price, a clear and concise statement of the method used to determine this value, the original cost of the property, the related accrued depreciation or amortization reserves, the amount of liability of contributions for extension, and a statement concerning any application the utility may have made to issue securities and to use the proceeds to pay for the property as well as what action has been taken on the application. The second exhibit is a statement showing the kind of materials and supplies to be purchased from the affiliated interest, the estimated amount to be purchased annually and the basis to be used in making charges against the applicant for the materials and supplies. If the application is for approval to loan the utility's funds, or give credit on its books or otherwise to an affiliated interest, then additional exhibits are required. For a utility to loan its funds to an affiliated interest, the exhibits are as follows: (1) a statement of the amount of money which the utility desires to loan to the affiliated interest, the terms of the loan, the rate of interest, the method of repayment, a list of security given (if any), and whether the loan is to be an open account or evidence by a promissory note; and (2) a statement on the use of the funds from the loan. For the case of a utility giving the affiliated interest credit on its books or otherwise, there are several variations in the required exhibits. If cash is to be advanced through an open or loan account, the utility must file two exhibits: (1) a statement of the amount of cash the affiliated interest will receive, the rate of interest, and the date and method of repayment; and (2) a definite statement of the purpose for which the advance will be used. If credit is to be given to the affiliated interest by the utility through a loan or open account, then an exhibit must be filed that contains a statement of the amount and description of each item for which the utility proposes to give credit through its loan or open account. For payment by the affiliated interests of accounts owned by the utility to a nonaffiliated interest, an exhibit must be filed that states the amount which the affiliated interest proposes to pay on behalf of the utility together with a description of the obligation and how it was incurred, and how the money to be paid will be used. Special provisions are made for an application to issue utility notes to an affiliated interest.

In the Matter of the Application of CP National Corporation for Approval of an Affiliated Interest Contract, Order No. 85-036 (Oreg. PUC, January 23, 1985).

The CP National Corporation, an Oregon electric, gas, and telephone utility, filed an application requesting an order authorizing payment to RAI Consultants, Inc., a wholly-owned subsidiary, for consulting services. From time to time, RAI advised and assisted CPN in telephone regulation and rate matters including toll settlements and operation studies, cost studies, and rate cases. The application was denied. The reasons given by the Commissioner for the denial were that it appeared in this case that a corporate shell was being used to accomplish a task at extra expense which could just as easily have been accomplished at less cost by the utility itself. Also, the Commissioner found that there was no apparent business reason for the separate corporation to exist. Further, the utility had not demonstrated that the proposed transaction would benefit the utility's ratepayers or that the subsidiary would keep its records in a manner in which the Commissioner could effectively evaluate the reasonableness of the utility's costs. Instead, it appeared that the proposed payment process would effectively shield the payments from any meaningful examination. For these reasons, the Commissioner denied the application on the grounds that it would be contrary to the public interest.

Pennsylvania--Pennsylvania Consolidated Statutes, §§2101-2107. (Chapter 21 Concerns Relations with Affiliated Interests).

Section 2101 defines affiliated interests. The expansive definition would include holding companies, affiliated companies, and other persons exercising a substantial influence over the policies and actions of the public utility. Section 2102 states that contracts or other arrangements between a public utility and an affiliated interest are not valid and effective unless and until the contract or arrangement has received the written approval of the commission. Special provisions are made for the approval of oral contracts. The commission will approve a contract or arrangement only if, upon investigation, it is clearly established that the contract or arrangement is reasonable and consistent with the public interest. If the commission determines that the expenditures payable (or paid) under a contract or arrangement are in excess of the reasonable price for furnishing the services or that the services are not reasonable, necessary, and proper, it will disallow the expense, insofar as it is excessive, in a rate case or proceeding involving the practices of the utility. The burden of proof is on the utility in any such proceeding to show that the expenditures are not in excess of the reasonable price and that the services are reasonably necessary and proper. There is, however, an exception to the provisions requiring commission approval. No such approval is required where the amount of consideration involved is not in excess of $10,000 (or 5 percent of the par value of outstanding common stock, whichever is smaller.) But, regularly recurring or continuing transactions which aggregate to a greater annual amount can not be broken down into a series of smaller transactions to come within this exception. The commission can approve prospectively a class or category of transaction; however, in any subsequent proceeding involving the rates or practices of the utility, the commission may disallow any payment or compensation for the transaction unless the public utility establishes its reasonableness. Section 2103 provides that the commission has continuing supervisory control over the terms and conditions of the contracts approved, pursuant to Section 2102, so far as is necessary to protect and promote the public interest. Further, the commission is not precluded from subsequently disallowing or disapproving expenditures made pursuant to contracts that it had approved if actual experience with the contract shows that the payments provided for or made were unreasonable. Section 2104 provides that the commission may require first, that any contract with an affiliated interest be in writing and second, that the contract contain a provision that the affiliated interest will at each billing provide a detailed statement of the cost of the items to it. Section 2105 provides that every contract with an affiliated interest made in violation of the law is void, and that any purchase, sale, lease, loan, or exchange under such contract (or under any contract with an affiliated interest where the terms of the contract have been breached) is unlawful. Section 2106 provides that the commission may disallow any portion of any payment or compensation to an affiliated interest under an existing contract or arrangement unless the public utility establishes its reasonableness. Section 2107 provides that this chapter is not applicable to the rates and related terms and conditions for the interstate transmission of electricity that have been submitted to and approved by a federal regulatory agency (in this case the Federal Energy Regulatory Commission) having jurisdiction, except that the commission may regulate the volume of purchases.

Texas--Texas Public Utility Regulatory Act, Article I, Section 3(i) and Article IX, Sections 67, 68; Article 1446c, Vernon's Texas Civil Statutes (as amended September 1, 1983).

Section 3(i) of the Texas Public Utility Regulatory Act defines affiliated interest or affiliate to include certain holding companies, affiliates, subsidiaries, and persons or corporations actually exercising directly or indirectly, a substantial influence or control over the policies or actions of the utility. Section 67 of the Act provides the Texas PUC with jurisdiction over any affiliated transactions, between affiliated interests and jurisdictional utilities, to the extent of access to all accounts and records of the affiliated interest that relate to the transaction, including accounts and records of joint expenses applicable to the transaction. Section 68 of the Act provides that the Texas PUC may require disclosure of the identity and interest of every owner with a substantial interest in the voting securities of any public utility or its affiliated interest. For this section, one percent or more is deemed a substantial interest.

The Substantive Rules of the Public Utility Commission of Texas, Sections 23.11(f) and 23.23(b)(2)(E) (as amended December 1, 1984).

Section 23.11(f) of the Substantive Rules requires that copies of contracts between any utility and any affiliated interest be filed with the Commission on request. The section also requires that, if the contract or arrangement is oral, it will be put in writing. In addition, all ownership and management relationships between companies or between companies and individuals, and all transactions with affiliates, including payments for interest expenses and the cost of any goods, services, property, or rights will be reported annually. Section 23.23(b)(2)(E) of the Substantive Rules provides that the utility has the burden of proving in each general rate case that all fuel and fuel-related affiliate expenses are reasonable and necessary for all fuels acquired from or provided by affiliates of a generating utility. The utility also has the burden of proving that the price charged to the utility for an item or class of items is no higher than the prices charged by the supplying affiliate to its other affiliates or to unaffiliated persons or corporations. The rule also provides that the affiliate's fuel price will be at cost with no return on equity included in the price. The Commission may consider the inclusion of an equity return for the affiliate in the rate of return and rate base during the utility's general rate case, but no equity return is to be considered a part of the fuel costs. The rule provides that the Commission will, from time to time, perform an investigation of all affiliated fuel suppliers and fuel supply services. The results of the investigation may be used in succeeding general rate cases, fuel cost reconciliation proceedings, emergency request proceedings, and elsewhere as deemed appropriate. The rule also provides that the affiliated companies will establish, maintain, and provide for Commission audit all books and records related to the cost of fuel. These records will explicitly identify all salaries, contract expenses, or other expenses paid or received among any affiliated companies, their employees, or contract employees.

Washington--Revised Code of Wahsington, Chapter 80.16 (Sections 80.16.010 through 80.16.090, inclusive).

Section 80.16.010 of the Code defines affiliated interest to include certain holding companies, affiliates, and corporations or persons with which the utility has a management or service contract. Section 80.16.020 of the Code states that no contract or arrangement for any services or property will be valid or effective unless the contract or arrangement has first received the approval of the Commission. Summaries of unwritten contracts or arrangements must be filed with the Commission. The Commission can approve the contract or arrangements only if it clearly appears and is shown after investigation that the contract or arrangement is consistent with the public interest. The Commission is not required to approve any contract or arrangement unless it has satisfactory proof of the cost to the affiliated interest of providing the services or property. Section 80.16.030 of the Code states that, in any proceeding involving the rates or practices of the utility, the Commission may (on its own motion or upon complaint) disallow any payment or compensation to an affiliated interest made under existing contracts or arrangements unless the utility establishes the reasonableness of the payment or compensation. Such disallowance may be in whole or in part in the absence of satisfactory proof that the amount is reasonable. Satisfactory proof to be submitted to the Commission includes the cost to the affiliated interest of providing the service or property. Section 80.16.040 of the Code provides that proof is not considered to be satisfactory unless either the original (or verified copies) of the relevant cost records and accounts of the affiliated interest or an abstract or summary that the Commission deems adequate, is included. Where reasonable, however, the Commission may approve or disapprove affiliated contracts or arrangements without the submission of cost records or accounts. Section 80.16.050 of the Code empowers the Commission to supervise the terms and conditions of the contract and arrangements so far as is necessary to protect and promote the public interest. The Commission has the same jurisdiction over subsequent amendments and modifications as it does over the original contracts or arrangements. Commission approval of a contract or arrangement does not preclude it from subsequently disallowing contract payments if actual experience makes it appear that the payments would be, were, or are unreasonable. The Commission reserves the power to revise and amend the terms and conditions of the contract or arrangement as necessary to protect and promote the public interest. Section 8016.060 of the Code states that, when the Commission finds that a utility is executing a contract or arrangement without prior Commission approval, the regulators may issue a summary order prohibiting the utility from treating payments made under the contract or arrangement as operating expenses or capital expenditures for rate or valuation purposes. This summary order is effective until the payments receive Commission approval. Section 80.16.070 of the Code allows the Commission to prohibit the utility from treating payments made under a contract or arrangement as an operating expense or capital expenditure if the Commission finds that a utility is making such payments where similar payments were disallowed and disapproved by the Commission in a previous proceeding involving the utility's rates or practices. Sections 80.16.080 and 80.16.090 of the Code provide for court action to enforce orders and appellate review of orders, respectively.

West Virginia--West Virginia Code, Sections 24-2-12, 24-2-12a, and 24-2-3. Section 24-2-12 of the West Virginia Code states, among other things, that no electric utility may by any means enter into a contract of service, property, or any thing with an affiliated interest, unless Commission approval is first obtained. The Commission may grant its consent in advance or grant exemptions from the requirements of this section upon a proper showing that the terms and conditions of the proposed transaction are reasonable, that neither party is given an undue advantage over the other, and that the transaction in question does not adversely affect the public. Any transaction that violates this section shall be void to the extent that the interests of the public are adversely affected. This section also states that the Commission may prescribe rules and regulations as necessary for the reasonable enforcement and administration of this section. (See West Virginia Public Service Commission Rules 10(i) and (j), described below.) Section 24-2-12a of the Code states that no public utility may issue stocks or other evidence of interest or ownership unless the Commission has approved the issue, its amount, and the purpose to which its proceeds will be applied, and the Commission feels that the issue is reasonably required for the stated purpose. Nonconvertible stock is not subject to this provision. Also the issuance of stocks or other evidence of interest or ownership by a corporation that devotes one or more of its divisions to providing public utility service is exempt from this section when the gross revenue from the public utility service represents less than twenty-five percent of the gross revenues generated by the corporation. The Commission may hold a hearing and may examine any witnesses, books, papers, documents, contracts, and other data that it deems necessary in making its decision of whether or not to authorize the stock issuance. The Commission may grant permission for the stock issuance in the amount applied for or in a lesser amount, may refuse such permission, or may grant it subject to any conditions that it deems necessary and reasonable. All stock or other evidence of interest or ownership issued by a utility without prior authorization by the Commission or without conformance to any of the provisions in the order of authorization is void. (This section is designed to allow Commission scrutiny prior to certain utility stock issuances, especially those for the purpose of corporate restructuring.) Section 24-2-3 of the Code provides, in part, that the Commission may investigate and review the transactions between utilities and affiliates in determining just and reasonable rates. The Commission may limit the total return of the utility to a level which, when considered together with the return earned by the affiliate on transactions with the utility, is just and reasonable.

West Virginia Public Service Commission Rules 10(i), and (j). These rules implement West Virginia Code Section 24-2-12, described in part above. Rule 10(i) states that a utility desiring to enter into a contract for any service, property, or any other thing will must file an application for Commission approval to do so. The application must set forth the name and address of the petitioner; the name and address of the affiliated interest; a copy of the contract; a full description of the nature and the character of the service, property, or things to be rendered to the petitioner; the compensation to be paid and its terms; the financial condition of the petitioner and the affiliated interest; the effect of the proposed arrangement on the service of the petitioner; if the affiliate is a West Virginia utility, the effect of the proposed transaction on its service; and a statement of the reasons why the petition should be granted. Rule 10(j) provides that a utility desiring the consent of the Commission in advance for a contract or an exemption from Section 12(f) of the West Virginia Code and Rule 10(i) must file a petition setting forth the name and address of the petitioner; a statement of the subsection or section of the requirement of which the advance consent or from which the exemption is sought including the reasons why the consent or the exemption is sought; the effect of a consent in advance or exemption on the service of the petitioner and any other utility operating in the state, if any; a statement that no party involved is given an undue advantage over any other and the reasons why this is so; and a statement why the petition should be granted and its effect on the public in the state.

Wisconsin--Wisconsin Statutes, Sections 196.52, 196.525 and 196.53. Section 196.52 of the Statutes defines affiliated interests to include certain holding companies, affiliates, corporations with interlocking directorates, or any corporation or persons who actually exercise substantial influence and control over the policies and actions of the utility. The section also states that, unless the Commission first gives its written approval, any contract or arrangement between a utility and its affiliated interest can not be valid and effective. Contract or arrangement here means a contract providing for the furnishing of any services, or for the purchase, sale, lease, or exchange of any property, right, or thing. The Commission can not approve any contract or arrangement unless it clearly appears and is established upon investigation that it is reasonable and consistent with the public interest. Further, the Commission may not approve any contract or arrangement unless satisfactory documentation is submitted on the costs to the affiliated interest of rendering the services or of furnishing the property or service to each utility. This documentation includes the original (or verified copies) of the relevant cost records and other relevant accounts of the affiliated interest, or an abstract or summary of the accounts and records if the Commission deems it adequate. The accounts must be properly identified and authenticated. The Commission may, where reasonable, approve or disapprove a contract or arrangement without submission of the cost records or accounts. There is an exception to the requirement for written approval of a contract or arrangement. The requirement does not apply if the amount involved is not in excess of $10,000 or 5 percent of the par value of the outstanding common stock, whichever is smaller. Regularly recurring payments under a general or continuing arrangement that aggregate to a greater annual amount, however, may not be broken down into a series of smaller transactions to come within this exemption. In a subsequent proceeding the Commission may exclude any payment or compensation made under an exempt transaction unless the utility establishes its reasonableness. The Commission also has continuing supervisory control over the terms and conditions of the approved contracts and arrangements as is necessary to protect the public interest. Also, the Commission has the same jurisdiction over contract modifications or amendments as it does over original contracts or arrangements. Commission approval of a contract or arrangement does not preclude the subsequent disallowance or disapproval of payments made or provided for if actual experience shows the payments to be unreasonable. The Commission reserves the power to revise and amend the terms and conditions of an approved contract or an arrangement to protect and promote the public interest. If the Commission finds upon investigation that a utility is executing a contract with an affiliated interest without Commission approval, it can issue a cease and desist order. A similar order can be issued if the Commission finds that a utility is continuing to make a payment to an affiliated interest even after the Commission had forbidden such payments in a previous proceeding.

Section 196.525 of the Wisconsin Statutes states, in part, that except under rules and regulations prescribed by the Commission, no utility may lend funds or credit to a holding company or a service company. The utility also cannot become surety, guarantor, or endorser of any of the holding company's or service company's obligations. The utility cannot loan funds, securities, or other similar assets to a holding company or service company. Nor can the utility purchase any obligation for which the holding or service company may be liable, whether solely or jointly. Any contract made in violation of these prohibitions is void and subject to cancellation and recoupment of funds or assets illegally loaned or transferred.

Section 196.53 of the Wisconsin Statutes provides that no license, permit, or franchise to own, operate, manage, or control any plant or equipment for the production, transmission or delivery of power will be granted or transferred to an out-of-state corporation.

Application of Madison Gas and Electric Company for Approval of an Affiliated Interest Contract with Magael, Inc., Commission Docket 3270-AU-100, Order (Wis. PSC, May 21, 1985).

The Madison Gas and Electric Company filed an application with the Commission for authority to enter into an affiliated interest agreement with Magael, Inc., a wholly-owned subsidiary. Under the proposed agreement the Madison Gas and Electric Company would furnish cash advances and provide accounting management, and maintenance services to Magael, Inc. Magael, Inc. was organized to engage in the business of acquiring real estate for the future plant expansion of its parent. The use of a subsidiary corporation for this purpose permitted the utility to acquire and hold such property outside of its mortgage trust indenture and avoided costly and time-consuming processing of a mortgate indenture and mortgage lien release. The Commission approved the contract subject to certain terms, conditions, and requirements. The Commission required that all charges made by Madison Gas and Electric Company be in accordance with the proposed contract, i.e. that the utility provide funds by transferring cash into the subsidiary's cash account, at which time the subsidiary would issue a check for payment of an expense or purchase of real estate. This would increase the account payable to the utility. The account payable was reduced when cash was transferred to the utility as a result of property sold or rental income received by the subsididiary, or when property was transferred to the utility at the subsidiary's original cost. All payments made by the utility to the subsidiary were to be made from retained earnings. The Commission also noted that it would review the level of cash advances for reasonableness in future rate cases. The Commission required that the cash advances be accounted for in Account 123.1, Investment in Subsidiary Companies, in accordance with the Uniform System of Accounts. Payroll costs for accounting, administrative, and maintenance services were directly assignable to the subsidiary, whenever possible. These costs included wages, salaries, and all applicable overhead costs. The Commission required the utility to file, as an attachment to its annual report an annual analysis of all amounts billed under the contract, including the dollar amounts for direct labor and overhead and the monthly level of cash advances. The utility must also inform the Commission prior to any suspension, modification, or termination of the contract. The Commission also set forth two additional caveats. First, approval of the contract by the Commission was not to be deemed a determination that charges under the contract were just and reasonable. Second, approval of the contract was expressly conditioned on the reserve power of the Commission to revise and amend its terms and conditions as necessary to protect and promote the public interest.

ANNOTATED BIBLIOGRAPHY

The following bibliography lists many of the sources used in this report, particularly in chapter 2. It also includes other works that the authors found in the course of their research for this study but did not necessarily cite in the report.

American Bar Association. Section of Antitrust Law. Vertical Restrictions upon Buyers Limiting Purchases of Goods from Others. Monograph no. 8. Chicago: American Bar Association, 1982.

This monograph covers, among other topics, exclusive dealing arrangements (including requirements contracts) and the Clayton Act and Sherman Act prohibitions against such arrangements. Ambiguities in the law are also discussed.

Andrews, Francis J., Jr. "Diversification and the Public Utility Holding Company Act." Public Utilities Fortnightly, December 23, 1982, pp. 24-28.

Andrews argues that the Public Utility Holding Company Act has accomplished its main objective of ensuring effective state regulation of utilities and that the law adds nothing to the safeguards for investors found in the 1933 and 1934 securities acts. The author also summarizes arguments for and against utility diversification. The latter set of arguments (those against) are in the form of regulators' reservations about utility diversification.

Baxter, William F. "Conditions Creating Antitrust Concern with Vertical Integration by Regulated Industries--'For Whom the Bell Doctrine Tolls.'" 52 Antitrust L. J. 243 (1983).

Baxter discusses conditions necessary for the application of the "AT&T doctrine." He also notes some criteria for and varieties of governmental action. Like the ABA monograph discussed above, this article is useful for raising issues that state regulators may need to consider when dealing with electric utilities and their subsidiaries.

Beedles, William L. "A Proposal for the Treatment of Double Leverage." Public Utilities Fortnightly, July 5, 1984, pp. 31-36.

Beedles proposes a capital structure method for dealing with double leverage. The method takes the firmwide equity cost as given and adjusts the reported capital structure. Beedles argues that the capital structure method looks more precisely at the types of risk that are relevant when determining rates of return.

Bolter, Walter G. "Restructuring in Telecommunications and Regulatory Adjustment." Public Utilities Fortnightly, July 5, 1984, pp. 15-22.

Bolter discusses the breakup of AT&T and diversification by the regional holding companies. The author suggests methods that regulators can use to avoid subsidization of diversification by ratepayers.

Christensen, Gary L., and Levy, Steven A. "The False Mystique of Broadband Technology: Utility Entry into Cable Television." Public Utilities Fortnightly, June 23, 1983, pp. 25-30.

The authors state that the arguments for electric utilities to diversify into cable TV have been overstated. They claim that the risks, both financial and regulatory, would exceed any benefits that a utility might gain.

Conerly, William B. "Diversification: An Economic Framework for Analysis." Public Utilities Fortnightly, September 16, 1982, pp. 40-43.

Conerly states that the ultimate corporate objective must be to maximize the value of the shareholders' equity while acting in a socially acceptable manner. Utilities must add the additional constraint of not harming ratepayers. The author concludes that major diversification efforts by utilities are not necessary and that the most successful utilities will be those (whether diversified or not) that have dealt with the problems facing the industry.

Corio, Marie R., and Condren, Alice E. "Which Coal at What Cost?" Public Utilities Fortnightly, March 15, 1984, pp. 32-36.

The authors discuss the problems that electric utilities face in obtaining quality coal for their power plants. They also discuss the effects of the different components of coal. (i.e. Btu content, ash, sulfur, and moisture) on plant performance. They note that the absolute value of the level of these substances in the coal burned in a plant is not as important as the difference between that level and the level that the unit is designed to burn.

Edelston, Bruce, and Sherman, Al. "Diversification by Electric Utilities into Load Management: Some Financial and Rate Implications." In Proceedings of the Third NARUC Biennial Regulatory Information Conference, pp. 215-223. Edited by Daniel Z. Czamanski. Columbus, Ohio: The National Regulatory Research Institute, 1982.

The authors analyze the impact of the formation by an electric utility of an unregulated subsidiary to sell load management devices to its customers. They use a computer model, the Planmetrics Screening System, to examine two cases: first, the utility continues its construction program with savings to customers resulting from fuel cost savings; second, the utility sells the excess capacity and energy resulting from the load management program to other utilities leading (in some cases) to both fuel and capacity savings to customers. They conclude that this type of diversification by an electric utility should be considered mainly as a way to reduce costs to ratepayers and that the impact on rates would depend greatly on utility operating and demand characteristics.

Edison Electric Institute: Electric Utility Diversification: A Guide to the Strategic Issues and Options. 3 vols. Washington, D.C.: Edison Electric Institute, 1983.

This work was one of the most comprehensive treatments of the topic found by the authors in the course of their research. Volume I, Handbook, includes a summary of the major issues, an overview of state and federal regulation, and a discussion of the implementation of a diversification plan by a utility. Volume II, Regulation, covers federal and state regulation in greater detail, contains comments on a preliminary draft of the report of the NARUC Ad Hoc Committee on Utility Diversification, and includes copies of selected state legislation and utility commission orders. Volume III, Research Reports, includes technical reports and case studies, sponsored by the Edison Electric Institute, that attempt to assess or document the effects of diversification on electric utilities. This volume also contains the results of a survey of electric utility diversification activities.

Elmer, Brian C., and Mazo, Mark E. "Utility Takeovers and the Holding Company Act." Public Utilities Fortnightly, September 30, 1982, pp. 17-22.

The authors state that repeal of the Public Utility Holding Company Act would remove a barrier to utility diversification, but it might also make utilities targets for takeover attempts by neighboring utilities, alternative utilities in the same area, or industrial users. The Holding Company Act requires approval by the Securities and Exchange Commission for purchase of as little as 5% of a utility's stock by another utility or by a holding company (whether regulated or nonregulated). In addition, any company, whether a utility or not, must register under the Holding Company Act with the SEC if it purchases 10% or more of a utility or a holding company. These are roadblocks that the Public Utility Holding Company Act places to anyone attempting to take over a utility.

Enholm, G. B.; Jaditz, T. M.; and Malko, J. R. "Electric Utility Diversification in the 1980s: A Challenge for Applied Regulatory Economics." The Journal of Energy and Development 8 (Autumn 1982): 109-126.

Enholm, Jaditz, and Malko discuss the financial problems facing electric utilities since the 1970s and diversification as an attempt by electric utilities to deal with those problems. The authors suggest three possible analytical frameworks that applied economists could use to conduct research in this area. Two of the frameworks are derived from behavioralist theory: managerial preferences and capital allocation. The third framework is taken from neoclassical theory: economies of scope. The authors encourage applied economists to conduct theoretical and empirical research on electric utility diversification.

Enholm, Gregory B., and Malko, J. Robert. "Electric Utilities in the 1980s: Financial Performance and Diversification." Paper presented at the 95th annual meeting of the American Economic Association, New York City, December 1982.

The authors perform an econometric analysis to examine the effects of a variety of variables on an electric utility's return on equity. They find Gross National Product, state population, and state per capita income to be particularly important. Average revenue per kilowatt-hour, used as a proxy for regulatory influence, was found to be statistically significant for eight of the twenty utilities examined. A correlation analysis, examining nine of the original twenty electric utilities (i.e., those that had diversified), provided limited, preliminary support for the hypothesis that state commissions with a good ranking from an investment perspective provide an incentive or climate for investor-owned electric utilities, within their jursidiction, to diversify.

Enholm, Gregory B., and Malko, J. Robert. "State Regulatory Treatment of Electric Utility Diversification." In Electric Power Strategic Issues, pp. 319-334. Edited by James Plummer, Terry Ferrar, and William Hughes. Arlington, Va: Public Utilities Reports, Inc., 1983. Palo Alto, Ca: QED Research, Inc., 1983.

The authors discuss, in the form of case studies, the policies used by five state utility commissions (Montana, New Mexico, New York, North Carolina, and Wisconsin) to deal with the unregulated subsidiaries of electric utilities. Enholm and Malko also discuss concerns that regulators may have over electric utility diversification. They include a list of questions for regulators to consider in the formation of policy on nonregulated businesses owned by electric utilities.

Enholm, Gregory B., and Malko, J. Robert. "Utility Diversification: Options for State Regulators." In Proceedings of the Third NARUC Biennial Regulatory Information Conference, pp. 175-191. Edited by Daniel Z. Czamanski. Columbus, Ohio: The National Regulatory Research Institute, 1982.

Enholm and Malko discuss regulatory issues, including legal, economic, and financial issues, raised by utility diversification. The paper includes a section on formulating regulatory policy on utility diversification. That section covers alternative goals that regulators may wish to pursue (such as assuring that ratepayers do not pay more than a reasonable cost for utility service and assuring that earnings from diversification are shared equitably), and options for commissions to consider in regulating utility diversification (i.e., regulate only the utility as before, monitor only diversified transactions involving the utility, monitor all diversified transactions, and regulate diversified activities as part of the utility).

Ferrar, Terry A. "Business Diversification: An Option Worth Considering." Public Utilities Fortnightly, January 7, 1982, pp. 13-18.

Ferrar argues that inflation and rising energy costs have broken down an historic implicit compact between regulators and electric utility investors. Under the compact, it was in the interest of investors to support utility management's placement of customer service as the primary corporate objective. Investors have suffered due to the harder times and corporate managers should base their decisions on parity between the interests of investors and customers. Ferrar states that ratepayers are also hurt by electric utilities' financial problems. He discusses a variety of arguments against diversification and concludes that prudent diversification by electric utilities can result in lower consolidated risk and higher returns.

Haar, Lawrence. "Diversification Argument Criticized." Public Utilities Fortnightly, April 1, 1982, p. 7.
In a letter to the editor of Public Utilities Fortnightly, Haar criticizes the article by Terry Ferrar summarized above. He states that the market will not place any value on the removal of diversifible risk. Only those diversification efforts that achieve economies of operation or other economies will affect the rate of capitalization and thus share prices. Haar argues furthur that Ferrar has confused a utility's portfolio with that of a market portfolio held by a given investor.

Hawes, Douglas W. "Utility Diversification under the '35 Act-SEC Light Changes from Red to Amber." In Utility Diversification: Strategies and Issues, pp. 87-111. New York: Public Utilities Reports, Inc., and The Management Exchange, Inc., 1981.
This paper was presented in accompaniment with a discussion that Aaron Levy and Hawes had on the Public Utility Holding Company Act at a conference on utility diversification (see below). It covers the provisions of the Holding Company Act and current (1981) Securities and Exchange Commission interpretation and enforcement of the law.

__________. Utility Holding Companies. New York: Clark Boardman Company, Ltd., 1984.
The preface of this book states that its purpose is to provide utility managers, their advisors, regulators, and others with a basic understanding of the modern utility holding company: how it is formed, its purposes, functions, operation, and regulation. The book is definitely a thorough treatment of the topic. Chapters cover such areas as the history of utility holding companies in the U.S., federal regulation of utility holding companies (the Public Utility Holding Company Act of 1935), state regulation of utility holding companies, pros and cons of utility diversification, a strategy for diversification, financing diversification, cost allocation, and affiliate transactions. An update of certain parts of the book was issued in July 1985.

Helman, Leonard A. "Diversification--Does the Public Service Company of New Mexico Case Predict Similar Reaction Elsewhere?" In Proceedings of the Third NARUC Biennial Regulatory Information Conference, pp. 192-198. Edited by Daniel Z. Czamanski. Columbus, Ohio: The National Regulatory Research Institute, 1982.
Helman discusses the nonutility diversification efforts of the Public Service Company of New Mexico. The arguments of the company and those opposing its diversification are discussed. The New Mexico PSC's General Order No. 39, setting forth various requirements for diversifying utilities, is summarized.

Illinois Commerce Commission Utility Diversification. Sunset Monograph no. 10. Springfield: State of Illinois, 1985.

This staff report provides an overview of utility diversification. Topics discussed include the organizational structures through which utilities can pursue diversification, cross-subsidization (and how regulators may prevent it), effect of diversification on a utility's risk and cost of capital, utility diversification in Illinois, and the authority of the Illinois Commerce Commission.

Levy, Aaron, and Hawes, Douglas W. "Holding Company Act Implications." In Utility Diversification: Strategies and Issues, pp. 24-86. New York: Public Utilities Reports, Inc., and The Management Exchange, Inc., 1981.

This is the text of a discussion that Levy and Hawes had at a conference on utility diversification. Their talks and questions-and-answers with conference participants covered such topics as provisions of the Public Utility Holding Company Act of 1935, including what the Act does and does not cover and exemptions from the Act. Other topics include corporate actions permissible under the Act and Securities and Exchange Commission enforcement of the law.

Lewis, Jordan D., and Ross, William Warfield. "A Road Map for Utility Diversification." Public Utilities Fortnightly, December 23, 1982, pp. 17-23.

The authors state that utilities' lack of the skills necessary for diversification is not a barrier but a starting point. They note that organizational and human resource development should be important parts of a diversification strategy. The authors also state that a utility should plan ahead to anticipate possible regulatory problems. They note that the energy and communications markets have changed and that utilities should act before others foreclose their options.

Malko, J. Robert. "Electric Utility Diversification: Devilish or Divine?" Paper presented at the 93rd Annual Convention of the National Association of Regulatory Utility Commissioners, San Francisco, California, November 1981.

Malko states that if it could be shown that utility diversification would not jeopardize adequate service for the public at reasonable cost, there would be little need for regulators to become involved. He notes that regulatory involvement with utility diversification depends on factors such as the form of organization chosen for diversification, and the anticipated size of the diversified activities.

Malko, J. Robert, and Enholm, Gregory B. "Electric Utility Diversification: Some Regulatory Concerns and Issues." Electric Ratemaking, April 1982, pp. 3-6.

The authors discuss the financial problems facing electric utilities and possible solutions for those problems. Solutions include reforming regulation, modifying utility operations, and diversifying utility operations. The article also covers the concerns that regulators may have with utility diversification.

Malko, J. Robert; Enholm, Gregory B.; and Jaditz, Theodore M. "Energy Utility Diversification, Holding Companies, and Regulation." Paper presented at the Fourth Annual Public Utilities Conference of New Mexico State University, El Paso, Texas, October 1981.

The authors discuss a variety of topics relating to utility diversification including reasons for pursuing diversification, possible organizational structures for diversification (organizing the activity within the utility itself, or as a subsidiary of the utility, or as a subsidiary of a holding company), and the advantages and disadvantages of those structures. The authors also discuss important legal, economic, and financial issues relating to utility diversification. Other sections of the paper cover alternative state utility commission goals and strategies, and diversification efforts by Wisconsin utilities.

National Association of Regulatory Utility Commissioners. *1982 Report of the Ad Hoc Committee on Utility Diversification*. Washington, D.C.: National Association of Regulatory Utility Commissioners, 1982.

The authors discuss regulatory issues, including legal, economic, and financial issues, that are relevant to utility diversification generally. Separate chapters then discuss diversification by electric utilities, gas utilities, telephone utilities, and water utilities. Other chapters include a summary of the 1972 report by the NARUC Ad Hoc Committee on Non-Utility Investments, Conclusions, and Recommendations. Appendices containing various state utility commission decisions and state statutes, plus a bibliography are also included.

__________. *1984 Report of the Ad Hoc Committee on Utility Diversification*. Washington, D.C.: National Association of Regulatory Utility Commissioners, 1984.

This brief (nine pages) report covers amendments to the Public Utility Holding Company Act of 1935. It includes a letter from utility representatives to Committee Chairman Stanley York discussing the proposed amendments and their modification to meet objections raised by NARUC.

"Note: Captive Coal Pricing and the Regulation of Utility-Affiliate Transactions." 68 *Virginia L. R.* 1409 (1982).

The author discusses approaches used by the Federal Energy Regulatory Commission and some state utility commissions to regulate affiliate transactions between an electric utility and its coal mining operations. The FERC employed a market price comparison approach, comparing the price charged by the affiliate to prices charged by independent suppliers. The states employed a rate of return standard, limiting the affiliate's rate of return to that of the utility. While concluding that the market price standard is preferable, the author proposes that regulators modify the test to enable ratepayers to share in the savings resulting from the affiliate transactions.

Rivkin, Steven R., and Carson, Virginia S. "The Coming Transformation in Electric Service: Entry into Cable Television." *Public Utilities Fortnightly*, February 4, 1982, pp. 21-27.

The authors argue that horizontal diversification into cable television and energy management through broadband communications facilities is a possible attractive business opportunity for electric utilities. A two-way interactive cable system connecting a utility with businesses and residences could be used for load management, billing, and payments. Rivkin and Carson state that cable TV is an option with promise equal to that of other business ventures being considered by utilities to bolster investor confidence. (See the article by Christensen and Levy, summarized above, for an opposing viewpoint.)

Rozycki, Christopher J., and Nelson, Richard A. "Electric Utility Diversification into Fossil Fuels." In *Proceedings of the Third NARUC Biennial Regulatory Information Conference*, pp. 199-214. Edited by Daniel Z. Czamanski. Columbus, Ohio: The National Regulatory Research Institute, 1982.

The authors report on a survey of seventy-six electric utilities around the U.S. conducted by the Technical Research Analysis Company for the Federal Energy Regulatory Commission in 1981. The survey was concerned with electric utility diversification into fossil fuel activities. Questions covered such areas as the structure of the subsidiary, why the utility chose to invest in a particular activity, the scope of subsidiary operations, subsidiary pricing of fuel sold to the parent utility, utility oversight of the subsidiary, and whether or not the subsidiary was regulated by a state utility commission. Forty-nine of the seventy-six utilities responded to the survey. Rozycki and Nelson propose in-depth case studies in order to assess the impact of diversification into unregulated markets on electric utilities.

Schuler, Richard E. "Utility Diversification: Public Policy Implications." Paper presented at the 1982 meeting of the Transportation and Public Utilities Group of the American Economic Association, New York City, December 29, 1982.

Schuler notes that diversification may be an attempt by utilities to achieve the deregulation of some aspects of their operations that are no longer natural monopolies. He also states that from the perspective of public policy, it should be shown that the higher rate of return and reductions in risk resulting from diversification are greater than what investors may obtain from diversifying their own portfolios. (This assertion applied to the case of diversification into unrelated businesses.) Regulators and diversifying utilities should establish a fair game with rules governing their relationship ahead of time.

Sherman, Roger. "Electric Utility Regulation and Performance after Diversification." Paper prepared at the Department of Economics, University of Virginia, Charlottesville, Virginia, November 1982.

The author notes the Averch-Johnson point that when more than one activity is included within a rate-of-return regulated enterprise, that entity can gain more scope to circumvent regulation. He states that dividing an electric utility into corporate entities might improve regulation because each entity could be controlled in order to eliminate cross-subsidization. Sherman notes that regulation is hindered when a business conducts operations across regulatory jurisdictions. He states that the boundaries of regulated units should be contained within one regulatory agency's jurisdiction where possible. Forming subsidiaries may help to comply with this principle by having separate subsidiaries operating in the jurisdictions of separate regulatory agencies.

Sillin, Lelan F., Jr. "Managing in Adversity: Utilities in an Inflationary Economy." Public Utilities Fortnightly, April 1, 1982, pp. 13-20.

Sillin discusses the financial difficulties of electric utilities, arguing that investors have not been treated fairly by regulators. He states that unbalanced regulation has forced transfer payments from investors to ratepayers in the form of artificially low rates. Sillin's proposed cures for the industry's problems include allowing "realistic" returns on equity and permitting utilities to earn those returns. Cash flow should be increased by the normalization of taxes and the inclusion of CWIP in the rate base.

Smackey, Bruce M. "The Case for Utility Involvement in Solar Domestic Water Heating." Public Utilities Fortnightly, April 1, 1982, pp. 28-35.

The author states that the assumption of an innovator role by utilities in the adoption of solar energy for domestic water heating might be a promising business opportunity. He notes that backward vertical integration, the main focus of utility diversification efforts, requires much capital. The energy conservation equipment market, in conjunction with renewable resources such as solar energy, could represent a forward integration opportunity requiring little capital from utilities.

Stelzer, Irwin M., and Schmalensee, Richard. "Potential Costs and Benefits of Vertical Integration." 52 Antitrust L. J. 249 (1983).

The authors discuss vertical integration by regulated firms. They note that the problem usually considered is that it is difficult for regulators to verify that transfer prices within the integrated corporation are appropriate except when spot markets are so well developed that there are unlikely to be gains from the integration. They note that issues addressed in the AT&T case should be considered. These include how integration changes the incentives of the regulated firm, whether the regulated firm can act on those incentives to inhibit competition somewhere, and whether socially beneficial competition would emerge in the absence of integration. The authors state that one should neither ignore the possible benefits nor over-emphasize the costs of vertical integration by regulated industries.

"The Conflict Between Managers and Shareholders in Diversifying Acquisitions: A Portfolio Theory Approach." 88 Yale L. J. 1238 (1979).

The author applies portfolio theory to managerial behavior to show that decisions to diversify are influenced by factors other than maximization of shareholders' wealth. The author notes that diversification may produce conflict between managers' interests and shareholders' interests. Management may pursue corporate acquisitions to reduce firm-specific risk and increase psychological and financial benefits to itself. Shareholders, however, do not benefit from the reduction of firm-specific risk as they have already eliminated such risk through portfolio diversification. The author states that the price of the acquiring firm's stock varies inversely with the size of the premium that that firm paid to the shareholders of the company that it acquired (in order to convince those shareholders to sell). Acquiring firms are penalized by an amount greater than the actual premium paid.

Thompson, Arthur A. "The Strategic Dilemma of Electric Utilities--Part II." Public Utilities Fortnightly, April 1, 1982, pp. 21-27.

Thompson discusses arguments for and against electric utility diversification. He also discusses the disadvantages of diversification into nonrelated products. These include utilities acquiring businesses in which they have no technological, managerial, or competitive experience and the problem of acquiring the necessary skills to manage a diversified business without distracting executive attention from improving utility performance. Thompson also discusses the problems connected with diversifying into other utility businesses and into alternate energy sources.

U.S. Congress. Congressional Research Service. Electric Utility Diversification, by Donald Dulchinos. Issue Brief No. 82060. Updated November 5, 1984.

This paper provides basic information on the topic. Subjects covered include issue definition, the Public Utility Holding Company Act and attempts to amend it, arguments for and against electric utility diversification, and the role of state regulation. A list of bills introduced during the 98th Congress plus lists of recent congressional hearings and additional reference sources are also included.

U.S. Department of Energy. Assistant Secretary for Policy and Evaluation. Office of Competition. Coal Competition: Prospects for the 1980s. Draft Report. Washington, D.C.: Government Printing Office, January 1981.

This report was prepared by the Department of Energy to fulfill a requirement of the Powerplant and Industrial Fuel Use Act. Thirteen government agencies were involved in the preparation of the study. Topics covered include seller concentration as a determinant of competition, factors affecting seller concentration (e.g. environmental laws, tax programs, and technology), and the effects of electric utility buyers on seller market power.

Utility Diversification: Strategies and Issues. New York: Public Utilities Reports, Inc., and The Management Exchange, Inc., 1981.

This book presents the proceedings of a conference on utility diversification. In addition to the discussion between Aaron Levy and Douglas Hawes and the accompanying paper by Hawes, which were listed previously in this bibliography, the volume includes presentations by Mitchell Kress on conference scope and objectives, by Dr. Irwin M. Stelzer on utilities as venture capitalists, by John W. Barr on acquisition financing, by Edward F. Burke on the state regulator's view of diversification, by Roger D. Feldman on federal regulatory issues, by David Marder on strategically planning diversification, and by Charles A. Benore and Anne F. Faber on financial analysts' and rating services' views of diversification. A number of case studies are also presented in the proceedings. These include Continental Telephone Corporation (by Robert E. LaBlanc), NICOR, Inc. (by Joseph M. Quigley), American Natural Resources Company (by Hugh C. Daly), Pacific Power & Light Company (by John H. Geiger), New England Electric System (by Bruce M. McCarthy), and Philadelphia Suburban Corporation (by John W. Boyer, Jr.). A presentation by Dr. Terry Ferrar on research by the Edison Electric Institute on electric utility diversification is also included.

Vondle, David P., and Ross, Elisabeth H. "The Regulation of Affiliated Interests." Public Utilities Fortnightly, June 7, 1984, pp. 32-37.

The authors discuss the relationship between a utility and its affiliated companies when all are part of a holding company system. The typical organization of a holding company system and the advantages to the utility of being affiliated with the holding company are covered. Vondle and Ross also discuss the problems posed for regulators by utility affiliation with a holding company. These include utility payments to affiliates, rather than retained earnings, being used to subsidize diversification, affiliates earning higher rates of return than those allowed the utility, utility payments to affiliates being higher and the quality of goods and services obtained being lower than what could be acquired on the open market, and employment and the purchase of goods and services being transferred out of state. The authors discuss the powers of state utility commissions over affiliate transactions. They also distinguish between three types of affiliates and propose guidelines for regulating each type.

Welch, Jonathan B. "The Regulatory Climate and Electric Utility Diversification." Public Utilities Fortnightly, November 22, 1984, pp. 45-47.

Welch discusses some of the studies conducted on the extent and impact of electric utility diversification. These include reports by the Edison Electric Institute, Morgan Stanley & Company, and the NARUC Ad Hoc Committee on Utility Diversification. He notes the potential benefits of electric utility diversification and the findings by some studies of better financial performance by diversified utilities. Using Argus Research Corporation's ratings of state utility commissions and examining the diversification activities (or lack thereof) of fifty-seven utilities studies by the Cabot Consulting Group (31 diversified, 26 nondiversified), Welch finds the diversified utilities to be located in less favorable regulatory climates. Similar results were found with other utility data sets and Welch concludes that the superior financial performance of diversified utilities cannot be attributed to regulation.

York, Stanley; Dube, Phyllis; and Malko, J. Robert. "Electric Utility Diversification: A State Regulatory Perspective." In Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries: Proceedings of the Institute of Public Utilities Thirteenth Annual Conference, pp. 577-591. MSU Public Utilities Papers. Edited by Harry M. Trebing. East Lansing, Michigan: Institute of Public Utilities, Michigan State University, 1983. The authors note the financial problems leading electric utilities to consider diversification. They also summarize major regulatory, legal, economic, and financial issues. A chronology of diversification efforts by Wisconsin utilities and a discussion of the work in 1971-72 of the NARUC Ad Hoc Committee on Non-Utility Investments and in 1981-82 of the NARUC Ad Hoc Committee on Utility Diversification are also included. The article concludes with a discussion of questions and concerns for regulators. The authors state that the challenge for state regulators is to develop a workable plan for utility diversification that will provide reasonable protection for the ratepayer while allowing utilities the opportunity to improve their financial positions.

York, Stanley, and Malko, J. Robert. "Utility Diversification: A Regulatory Perspective." Public Utilities Fortnightly, January 6, 1983, pp. 15-20.

The authors describe the activities and summarize the official report of the NARUC Ad Hoc Committee on Utility Diversification, which York chaired. They discuss three categories of regulatory issues: legal, economic, and financial issues. The authors also summarize the Committee report's recommendations.