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CEO Compensation after Deregulation: The Case of Electric Utilities*

The 1992 National Energy Policy Act (NEPA) intensified competition in the electric utility industry by allowing nonutility generators to produce and sell power in wholesale energy markets. Congress expected NEPA to lead to improved operating efficiencies by substituting market forces for regulation. A data set that is unique to the utility industry allows us to test how and whether utility firms reallocated resources to improve efficiencies and, more important for this study, whether CEO compensation changed in accordance with agency theory predictions that CEO compensation would become more incentive-based and more equity-based in the competitive operating environment.

I. Introduction

The 1992 National Energy Policy Act (NEPA) had an impact on the level of competition in the electric utility industry in two major ways. First, nonutility power generators were allowed to produce and sell power in wholesale electricity markets. Second, nonutility power generators could obtain access to transmission lines to deliver their power to distant customers. Thus, of the three main functions of the electric utility industry—generation, transmission, and retail—the generation of electric

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power is no longer a regulated monopoly. However, the Federal Energy Regulatory Commission (FERC) retains oversight of transmission lines and local public utility commissions (PUCs) continue to regulate the distribution and retail of electricity to final users.

Financial economists have long sought to verify empirically that firms design management compensation contracts to mitigate agency conflicts. The intuition behind this general hypothesis is that managers behave in a manner consistent with their compensation. Earnings-based cash compensation rewards managers' operating performance from the existing assets in place (e.g., Natarajan 1996). Stock option compensation aligns managers' interest with those of shareholders and encourages risk-averse managers to invest in risky projects (Bryan, Hwang, and Lilien 2000). Thus, the changed regulatory environment in the electric utility industry provides a setting in which to test these theories of executive compensation with respect to both cash and option compensation.

Electricity, as a commodity, is differentiable by price. With competitors now allowed to sell in local and in distant markets, price competition increased under NEPA, requiring electric utilities to control costs. The new competitive environment also induced utilities to seek new value-added products or lines of business in order to maintain or improve firm performance. In an agency context, both effects (controlling costs and seeking new investment opportunities) require incentives to management. Since a major objective of NEPA was an improvement in operating efficiencies through the substitution of market forces for regulation, we expect firms to have undertaken means to improve efficiencies, and to motivate CEOs to make decisions consistent with the new competitive environment, we expect significant changes in compensation magnitude and structure.

A data set unique to the utility industry allows us to determine whether utilities reallocated resources in a systematic way after deregulation. The Federal Energy Regulatory Commission requires utilities to file Form 1, which gives detailed, component-level performance results.[1] We found that firms made significant operational changes, such as outsourcing power production and reducing the number of employees and labor cost. The changes resulted in improved operating margins at the utility segment. However, the improvements were not sustained throughout the entire sample period.

With respect to CEO compensation, we hypothesize that the magnitude of compensation will increase to attract and retain executive talent in

1. FERC Form 1 is the "Annual Report of Major Electric Utilities, Licensees, and Others," required under CFR Sec. 141.1 OMB No. 1902-0021. It is a comprehensive report for electric rate regulation and financial audits. Major electric utilities are defined as those with (1) 1 million megawatt hours or more, (2) 100 megawatt hours of annual sales for resale, (3) 500 megawatt hours of annual power exchange delivered, or (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

an environment of increased competition. CEOs likely bear more risk in a competitive environment, in part because more of their pay is "at risk" in the form of incentive pay. Therefore, they demand higher levels of compensation. We also hypothesize that the proportion of compensation that is incentive-based will increase, since boards of directors will likely link more CEO compensation to firm performance because of the need to increase firms' operating performance from assets in place and exploit investment opportunities. We find that each component of compensation increased significantly for CEOs in the deregulated period from the regulated period. More important, the structure of compensation, such as the ratio of incentive-based compensation to total compensation and the ratio of equity-based compensation to total compensation, also changed significantly.

Since cash compensation remains the predominant form of compensation for utility CEOs over our sample period and cash compensation is theoretically tied to accounting-based performance measures, we tested whether CEO cash compensation because more responsive to accounting earnings during the deregulated period compared to the regulated period. Using data from FERC's Form 1, we also tested whether cash compensation is associated with internal performance (efficiency) measures in addition to accounting earnings. We focus our study on the efficiency measures suggested by the firms themselves in their Management Discussion and Analysis (of Form 10-K) and in their proxy statements in the section dedicated to a discussion of CEO compensation.[2] The FERC data allow us to test whether CEO compensation is structured around performance measures that are deeper in organization where firms attempt to improve efficiencies. We found that the association between changes in cash compensation and changes in accounting earnings is statistically significant during the deregulated period but not during the regulated period. We also find that the association between changes in cash compensation and changes in component-level gross margins becomes statistically significant during the deregulated period, but only when we omit the final 3 years of the sample, which correspond to worsening operating margins. We infer that cash compensation became delinked from these Form 1 measures as they deteriorated. This inference is corroborated by a detailed analysis of proxy statement disclosures in which utility firms discuss their compensation plans. Finally, we also find that equity-based compensation increased significantly in the deregulated

2. We acknowledge that other theoretical measures of efficiency exist. For instance, some papers have developed and used proxies for allocative and technical efficiency. Using this distinction, Uri (2001) studied efficiency changes in the telecommunications industry and Wheelock and Wilson (1995) studied efficiency changes in the banking industry. Also, Pollitt (1997) focused on the differences in efficiency measures by form of ownership (private vs. public) and nationality. However, in this paper, we focus on those measures that firms state (in their Form 10-Ks and proxies) they are trying to improve.

environment and that stock option compensation is significantly associated with theory-based determinants. Specifically, electric utilities' investment opportunity set, leverage, size, and free cash flows are significant explanatory variables of stock option compensation in the deregulated period.

To determine whether secular trends or the event of deregulation drive the results with respect to CEO compensation, we constructed a sample of control firms in unregulated industries throughout the sample period. We found insignificant changes in the proportions of equity-based compensation and marginal changes in the proportions that are incentive based. These results show that the changes for utility firms are of several orders of magnitude higher than those for the control firms and, therefore, likely attributable to the change in the regulatory environment in the utility industry. The results are also consistent with theory. In the utility industry, the requirement for incentive compensation is lessened under regulation, since direct monitoring serves to reduce agency costs of equity. During deregulation, the need for incentive compensation increases due to reduced regulatory oversight, not only in the utility segment but also in new segments into which utility firms are now allowed to venture. This latter point also underscores the need to increase stock-option compensation to induce risk-taking behavior into such new ventures.

Two previous studies document the effects of deregulation on compensation structure in the banking industry. Crawford, Ezzell, and Miles (1995) show that sensitivity of CEO compensation to banks' stock price performance increased after regulatory changes in the early 1980s. Hubbard and Palia (1995) found higher levels of CEO pay and a stronger compensation/stock-price performance relation for banks operating in an environment where interstate banking is permitted. More recently, Kole and Lehn (1999) studied the effects of deregulation in the airline industry and documented that ownership concentration increases subsequent to deregulation, as does CEO compensation, particularly in the form of stock options.

We show that electric-utility CEO compensation becomes more performance based after deregulation, consistent with the previous literature but in a different industry setting. Also, however, we show that the targeted performance measures reach deep into the organization. The data that we collect from the FERC on component-level performance measures allow us to document these relations. We also document major resource reallocation after deregulation. Finally, we test the relation between equity-based pay and hypothesized economic determinants. The operating environment for electric utilities under deregulation is characterized by greater investment opportunities, which call for increased stock option awards relative to cash compensation.

The remainder of the paper is organized as follows. Section II discusses the changes in the regulatory environment in the electric utility industry and develops research hypotheses. Section III discusses the research design and the sample. Section IV provides empirical evidence, and Section V concludes the study.

II. Increased Competition in the Utility Industry and CEO Compensation

A. Increased Competition: Unbundling of Generation from Transmission and Retail

Although NEPA establishes the demarcation between the regulated and deregulated time periods in our study, previous legislation set the stage for the eventual deregulation that followed. Specifically, the Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 with the goal of reducing the dependence on imported oil and encouraging the use of renewable and alternative energy sources. PURPA also had the effect of promoting competition in power generation by requiring utilities to buy power from nonutility generating companies or "qualified facilities" (QFs). However, since QFs were allowed to sell only to local utilities and to charge rates equal to the utilities' avoided costs, the effects of PURPA on increasing competition were limited.[3] NEPA extended PURPA by allowing non-utility generators (including QFs and independent power producers, or IPPs) to sell power in the wholesale market at market-based rates. These rates, until very recently, were generally significantly lower than previously regulated rates because nonutility generators use newer and more efficient technology. NEPA also authorizes the Federal Energy Regulatory Commission to order utilities to provide transmission access to other utilities and to nonutility generators on a non-discriminating basis.[4] Therefore, market-based wholesale prices (rather than "avoided-cost" rates) are now available to both local and distant utilities.[5] However, NEPA does not extend competition to the final distribution of electricity. Therefore, retail operations are still viewed as natural monopolies and regulated by state public utility commissions (Blacconiere, Johnson, and Johnson 1997).[6]

Congress's intent in passing NEPA was to create an electric power market that relies on competitive forces to discipline prices and bring about economic efficiencies. On the one hand, the loss of monopoly power in the generation segment diminishes utilities' stable operating environment. On the other hand, deregulation provides the advantage of

3. The electricity rates were set equal to the incremental cost that the utilities would have incurred had they produced the power themselves. Appendix A describes briefly the general operating and regulatory environments of the electric utility industry prior to the 1978 act.
4. Unlike PURPA, NEPA did not obligate utilities to purchase power from IPPs.
5. The *Economic Report of the President* (1996) also indicates that nonutilities' share of nationwide generating capacity doubled from 3.6% in 1987 to 7.2% in 1995.
6. Many states are currently considering opening the retail segment of the industry to competition.

buying power from third parties at competitive, presumably lower, market rates. If, in fact, these rates are lower than the previously regulated rates, then high-cost producers, in particular, benefit. Additionally, the need to expand capacity can be reduced as long as market mechanisms induce third parties to generate power.

The advancement of competition in the generation and wholesale markets increases managerial incentives to improve electric utilities' operating efficiencies (Moyer 1993 and 1996). Since much of utilities' cost structure is associated with both past investments and fuel expenses (which cannot be reduced significantly in the short run), improved operating performance becomes more important in enhancing shareholder value. Utility managers achieve gains in operating efficiency by increasing the utilization of excess generating capacity, improving the condition of existing plants, and enhancing employee productivity.[7]

B. Firms Discussions of the New Deregulated Environment

Publicly traded firms are required, under Securities and Exchange Commission (SEC) rules, to discuss the competitive environment (in "Item 1—Business" of Form 10-K) and any known trends, demands, commitments, uncertainties, and events that may materially affect the results of operations, liquidity, and capital resources (in "Item 7—Management Discussion and Analysis" of Form 10-K). Firms must include descriptions and amounts of matters that would have an impact on future operations and that have not had an impact in the past (Release No. 6231, SEC 1980). We analyzed each utility's Form 10-K, both Item 1 and Item 7. We chose the year 1995, 3 years after the enactment of NEPA.

In Appendix B, we give examples of utilities' Form 10-K disclosures that we examined. Also in Appendix B, we give a summary of our analysis. We categorize the responses into two main groups: those that pertain mainly to current "assets in place" and those that pertain to new "investment opportunities." As Appendix B shows, firms articulate the concern over cost control and cost reduction, which they attempt to attain by improving efficiencies, reducing staff, and eliminating duplicate functions. Firms also, however, mention a variety of ways of finding and developing new investment opportunities, such as developing high value-added services, undertaking mergers and acquisitions, investing in nonregulated projects, and diversifying internationally. Finally, firms

7. Several federal acts, as well as FERC orders, also deregulated parts of the natural gas industry (Standard Industrial Classification codes 1311, 4922, 4923, 4924). The major relevant acts are the Natural Gas Policy Act (1978), FERC Order 436 (1985), FERC Order 500 (1987), and the Natural Gas Wellhead Decontrol Act (1989). The Natural Gas Wellhead Decontrol Act completed the deregulation of wellhead prices, allowing them to be set freely in the market. To the extent that our sample firms have lines of business in the natural gas industry, any effects on the compensation structure attributable to these earlier deregulation efforts in the natural gas industry would bias against our findings.

mention two "other" items that they feel would result from deregulation: increased business risk, which that would in turn affect credit quality and investor returns; and creation of stranded plant investments and stranded supply contracts.

To assess the basis for CEO pay in the deregulated period, we studied firms' narrative disclosures in their annual proxy statements. SEC proxy rules require firms to address their CEO-compensation policies. Typically firms provide narrative disclosures that describe, in general terms, the performance measures used in CEO compensation contracts as well as major changes in those performance measures. We chose 1995 to assure a reasonable amount of time for adjustments to compensation structure in the new competitive environment. In addition to year 1995, we chose 2001 to determine whether incentive compensation structure was sustained. We give examples of narrative proxy disclosures in Appendix C.

In Appendix D, we give a summary of our analysis of bonus formulas as discussed in proxy statements. As reported in the first column in Appendix D, 58.6% of the firms cite earnings per share (EPS) as one measure used in determining the CEO's bonus. This frequency is similar to that for year 2001 (53.5%). For 1995, 41.4% of the firms tie the CEO bonus to operation and maintenance (O&M) expenses, either exclusively or in addition to EPS or other measures. However, for 2001, the frequency of firms using O&M in their bonus formula drops to 4.7%. Other notable changes in performance measures used in the bonus formulas include "customer satisfaction" (from a frequency of 30.3% to 11.6%); stock returns (15.2% to 2.3%), and cost per Kwh (13.1% to 0.0%).

Of the firms that give specific performance measures for the bonus, 26.3% give details of the bonus formula in 1995, compared to 15.5% in 2001. The average weight on EPS is 51.9% and 63.0%, for 1995 and 2001, respectively. That is, for these firms, over one half to almost twothirds of the bonus is determined by EPS. The second-highest weight is on return on equity, or ROE (49.7% and 32.0%). The average weight on O&M, for those firms that use O&M and give the details of their bonus formulas, is 24.3% and 25.0% for years 1995 and 2001, respectively. The weighting on cash flow remains stable at 22.5%. In all, three of the major items (EPS, O&M, and ROE) pertain to earnings, which supports the theoretical prediction that cash compensation, of which the bonus is a component, is tied to an earnings metric.

C. Cash Compensation

Prior executive compensation studies suggest that earnings-based cash compensation (salary and bonus) and stock-based compensation (stock options and stock ownership) provide different incentives to the managers to undertake different types of managerial activities (Bushman and Indjejikian 1993; Barclay, Gode, and Kothari, 1997). CEO cash compensation likely encourages improved stewardship of assets in place

(Natarajan 1996), and stock-based compensation likely encourages exploitation of future investment opportunities (Smith and Watts, 1992). Stock-based performance measures provide a more accurate, timely assessment of managers' investment decisions for those firms whose value critically depends upon the exploitation of future investment opportunities. By comparison, accounting earnings of such firms are less-efficient performance measures, since they reflect managerial investment efforts on firm value often with a substantial time lag, due to the generally accepted accounting principles' emphasis on verification, matching, and conservatism (Amir and Lev 1996). We base our hypotheses on these theoretical distinctions between earnings-based cash compensation and price-based stock-option compensation.

We hypothesize that firm value of electric utilities is initially more dependent, subsequent to NEPA, on improved operating efficiency from the existing asset in place. Efficiency gains are necessary because of the nature of utilities' investments and cost structures. The realization of seconomic gains requires greater managerial effort and therefore increased managerial incentives.

In light of the theoretical prediction, as well as the evidence from the Form 10-K and proxy filings, we expect the magnitude of CEO compensation to increase to compensate CEOs for additional risk and effort borne in the competitive environment. We also expect the proportion of CEO compensation that is incentive based to increase post NEPA. We expect CEO cash compensation to be more sensitive to earnings in the 1993–2001 period than in the 1990–92 period. Further, given the focus on expense control, we expect that CEO cash compensation is more sensitive to component-level gross margins (GM) and component-level operation and maintenance expenses in the 1993–2001 period than in the 1990–92 period. In particular, we expect a significant, positive (negative) relation between changes in GM (O&M) and changes in CEO cash compensation.

FERC Form 1 disclosure requirements allow us to test the explanatory power of component-level data for CEO compensation. In Appendix E, we give the data items that we sampled. We focus on the relation between operating revenue (oprev) and operation and maintenance expense, O&M. We measure O&M as opexp plus maint, where O&M represents total O&M for the firm. We also obtain O&M by the three main functions of the electric utility component: pronm (total power production expenses), tronm (total transmission expenses), and retonm (total retail expenses, which is the sum of dsonm [distribution], caonm [customer accounts], csonm [customer service], and rvonm [sales expenses]. The difference between oprev and O&M is the component-level gross margin that we tested. We also tested O&M independently. Finally, we tested O&M decomposed into the three functional areas: pronm, tronm, and retonm.

D. Stock-Option Compensation

Of the two main forms of equity-based compensation (restricted stock and stock options), we focus on stock-option compensation since this form of equity-based compensation has been shown to be used more by firms with greater investment opportunities (Bryan et al. 2000). Efforts to expand and exploit the investment opportunity set has been suggested by electric utilities in their annual Form 10-Ks, as noted in Appendix B. We expect the proportion of compensation that is equity-linked to increase post NEPA.

Investment opportunity set (IOS). Firms with abundant investment opportunities have a range of possible investment decisions that is known fully only to the CEO. It is difficult for shareholders to alleviate this information asymmetry without special knowledge or information. Therefore, such firms are likely to rely on equity-based compensation, including stock options (Smith and Watts 1992; Bizjak, Brickley, and Coles 1993; Gaver and Gaver 1993). More important, CEOs (who are unable to diversify their human capital) differ in risk tolerance from shareholders (who are able to diversify their investment portfolios). Thus, shareholders want their risk-averse CEOs to accept risky yet value-increasing investment projects. For these theoretical reasons, along with the disclosures we document in Appendix B pertaining to investment opportunities, we focus on stock-option compensation. We expect high IOS utilities to use relatively more stock-option compensation than cash compensation.

Agency cost of debt. If incentive plans align the interests of managers and stockholders at the expense of debt holders, then debt holders demand a premium for the potential increase in firm risk. Since stockholder-debt holder conflicts are greatest when the probability of financial distress is high, heavily leveraged firms have incentives to decrease the incentive intensity and the mix of stock-based awards (John and John 1993; Yermack 1995).[8] We therefore expect highly leveraged firms to use more cash compensation relative to stock compensation.

Liquidity constraints. Stock-based compensation conserves cash on the grant date and, in the case of stock options, represents a source of cash on the exercise date. Therefore, we expect firms with liquidity constraints to compensate their CEOs more with stock-based compensation than cash compensation.

Firm size. Information asymmetry tends to increase in firm size. Jensen and Meckling (1976) contend that a larger span of firm operations allows for greater managerial opportunism and less-effective external monitoring. Bryan et al. (2000), Yermack (1995), and Gaver and Gaver (1993) find that bigger firms pay managers with significantly larger

8. Another reason to expect a negative relation between leverage and stock option awards is that high leverage reflects a small investment-opportunity set, since firms with a large fraction of assets in place tend to employ more debt (Myers 1977; Smith and Watts 1992).

relative amounts of stock-based compensation. The authors also attribute this relation to the greater degree of difficulty in monitoring managers of larger companies. Thus, we expect a positive relation between firm size and the relative use of stock option compensation.

III. Research Design

Our sample consists of all firms in SIC codes 4911 and 4931 that have the required CEO compensation, financial, and stock price data available. We obtained the data on CEO compensation components from the proxy statements for the test period 1990–2001. We focused on this period, because, since 1990, the proxy disclosures include the required details on CEO compensation.[9]

We focus on the following components of CEO compensation: salary, annual cash bonus, the value of stock options granted, the value of restricted stock grants, and long-term incentive plan payments. To measure the value of the stock options, we use the Black-Scholes (1973) model. Data on the parameters for the Black-Scholes option-valuation model are from the Compustat and the Center for Research in Security Prices (CRSP) databases.

We do not include in our measures of CEO compensation "other cash payments" such as pension contributions, health insurance premiums, and various expense reimbursements, since these payments are not directly related to firm performance. We limit our sample to those firms whose CEOs are the same individuals for at least 2 consecutive years, since our measure of compensation (i.e., the change in CEO compensation) requires CEO compensation data for a 2-year period.

One potential alternative explanation for the increase in the cash compensation-earnings sensitivity in the post-1992 period is greater public scrutiny and concern over executive compensation packages by both regulatory authorities and shareholders. In 1992, the SEC expanded the disclosure requirements on executive compensation and firm performance. The expanded public disclosures might have pressured boards of directors to link more closely executive compensation to firm performance in the post-1992 period. Similarly, the Revenue Reconciliation Act of 1993 disallows deductions for executive compensation in excess of $1 million that is not performance based.[10] To the extent that public

9. The SEC proxy rules enacted in 1992 require public companies to present (1) compensation tables that detail the components of compensation, (2) a comparison of the firm's stock performance relative to certain market and industry indices, and (3) a report by the compensation committee on the executive compensation policies (SEC 1992).

10. To qualify as performance-based compensation under the section 162(m) of the 1993 act, the compensation must be (1) established by a compensation committee of the board of directors,

companies have incentives to preserve the tax deductibility of executive compensation by including a performance based component, it is plausible that the 1993 Reconciliation Act might have contributed to the increase in the proportion of compensation that is incentive-based after 1993.

To determine more clearly whether changes in CEO compensation are attributable to these regulatory changes, instead of the effect of deregulation of the electric utility industry, we examine a sample of nonutility firms. Since earlier studies show that managerial incentive agreements are related to firm size (Smith and Watts 1992; Gaver and Gaver 1993), we control for the size effect in the selection of the control firms by matching the control on total assets. The control sample consists of 101 firms drawn from 30 different, unregulated businesses.[11] The purpose of the control is to focus on whether the control firms' compensation magnitude and proportions changed significantly from the 1990–92 period to the 1993–2001 period.

With respect to component-level operating and performance data, we obtain each utility firms' FERC Form 1. The Federal Energy Regulatory Commission requires utilities to provide (on Form 1) details about revenues and expenses associated with each functional area as well as a range of nonfinancial data, such as the amount (and cost) of power purchased and generated, types of fuel, number of employees by function, amount of transmitted power, and retail prices.[12] Form 1 standardizes account definitions, thereby allowing us to obtain a consistent measure of internal expense allocations across firms.

In the cash compensation models we use annual earnings (before extraordinary items and discontinued items), component-level gross margin (GM), total O&M, production O&M, transmission O&M, and retail O&M. These metrics are measured as percentage changes. Cash compensation is measured as CEO salary plus bonus.[13]

Our cash compensation models (without firm and year subscripts) are

$$\text{Model 1:}\quad \%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + b(\%\Delta\text{AccE}) + h\text{OWN} + i\text{Regenv} + \varepsilon,$$

which consists solely of outside directors; (2) disclosed to and approved by shareholders; (3) based upon attainment of an objective, preestablished performance goal; and (4) paid only after the compensation committee certifies the attainment of the relevant performance goal.

11. On average, the control firms are more profitable and have higher firm value, greater systematic risk, lower firm leverage, and greater managerial ownership.

12. The data, although self-reported, are uniform across firms since the FERC requires adherence to a uniform system of accounts.

13. We do not include cash payments made in accordance with performance plans and performance units, because these compensation arrangements usually cover a 3–5-year performance period.

$$\text{Model 2: } \%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + c(\%\Delta\text{GM}) + h\text{OWN} + i\text{Regenv} + \varepsilon,$$

$$\text{Model 3: } \%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + d(\%\Delta\text{O\&M}) + h\text{OWN} + i\text{Regenv} + \varepsilon,$$

$$\text{Model 4: } \%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + e(\%\Delta\text{PrO\&M}) + f(\%\Delta\text{TrO\&M}) + g(\%\Delta\text{RetOM\&M}) + h\text{OWN} + i\,\text{Regenv} + \varepsilon,$$

where

$\%\Delta\text{Cashcomp}$ = year-to-year percentage change in CEO's salary plus bonus;
$\sum_{t=\text{Begin}}^{\text{End}} \text{Years}$ = indicator variables for the years in the respective sample periods, either 1990–92, 1993–2001;
$\%\Delta\text{accE}$ = year-to-year percentage change in annual earnings before extraordinary items and discontinued operations;
$\%\Delta\text{GM}$ = year-to-year percentage change in annual gross margin, measured as operating revenue at the electric utility component less O and M, as reported on FERC Form 1;
$\%\Delta\text{O\&M}$ = year-to-year percentage change in total annual operation and maintenance expenses as reported on FERC Form 1;
$\%\Delta\text{PrO\&M}$ = year-to-year percentage change in annual production-related operation and maintenance expenses as reported on FERC Form 1;
$\%\Delta\text{TrO\&M}$ = year-to-year percentage change in annual transmission-related operation and maintenance expenses as reported on FERC Form 1;
$\%\Delta\text{RetO\&M}$ = year-to-year percentage change in annual retail-related operation and maintenance expenses as reported on FERC Form 1;
OWN = managerial stock ownership;
Regenv = indicator variable for regulatory environment.

The coefficient *b* reflects the cash compensation-earnings performance sensitivity, and coefficient *c* represents the sensitivity of cash compensation to changes in component-level gross margin. The coefficient *d* reflects the sensitivity of cash compensation to changes in component-level operation and maintenance expense, and coefficients *e, f,* and *g* represent the sensitivity of cash compensation to the three main components of total O&M. We include Model 4 because the deregulation of the utility industry is not uniform across all major functions of electric utility firms. We estimate the parameters separately for the 1990–92 period and the 1993–2001 period.

We include year indicator variables to control for the fixed year effects on our dependent variables. We include OWN to control for managerial ownership. Additional incentive-based compensation is likely reduced for CEOs with higher equity holdings, thereby affecting the association between changes in cash compensation and changes in performance measures. We also control for utilities' regulatory environment (Regenv), since the magnitude of CEO compensation and the proportion of incentive-based compensation are lower for electric utilities operating in a regulatory environment characterized as unfavorable (Abdel-khalik 1988; Bryan and Hwang 1997).[14] Electric utilities operating in an environment classified as unfavorable are more closely monitored and face greater political constraints, thereby reducing the need for incentive-based compensation.

As our proxy for the regulatory environment, we use a measure of firms' diversification. A utility's diversification is associated with the adoption of a holding company structure and various unregulated businesses (Lanen and Larcker 1992) and substantial diversification into unregulated businesses loosens political constraints on CEO compensation, since compensation can be charged to the unregulated operations (Joskow, Rose, and Shepard 1993). To the extent that the direct monitoring by the regulatory body is absent for the unregulated operations, electric utilities that diversify into unregulated businesses are more likely to rely on incentive-based compensation agreements. Hence, we expect that greater diversification could increase the incentive-based proportion of compensation and affect our regression results. Our measure for the regulatory environment (Regenv) is from Compustat's Business Segment files. If a utility has two or more lines of business, Regenv is assigned the value of 1; otherwise 0.[15]

14. In the mid-1990s, Merrill Lynch ranked utilities' regulatory environment. This ranking has been shown to be associated with certain aspects of CEO compensation. For instance, the pay-performance sensitivity is lower for utilities operating in an environment characterized as relatively "pro-consumer" (Joskow, Rose, and Wolfram 1996). However, Merrill Lynch's most recent ranking that we could obtain was for year 1995. Therefore, we use the alternative proxy of diversification, as discussed in the body of the paper.

15. In the deregulated period, state wide public utility commissions, continue to exert varying levels of oversight on utilities. We test whether this cross-sectional variation in regulatory environment affects the magnitude and the structure of utility CEO compensation during the deregulated period. Similar to previous research (Bryan and Hwang, 1997), we document significant associations between the magnitude of compensation and the regulatory environment during the deregulated period as well as between the proportion of incentive-based compensation and the regulatory environment. Overall, these replicated results are consistent with the arguments that greater constraints imposed by a strict regulatory environment affect the structure of managerial compensation contacts (e.g., Joskow et al. 1993; Jensen and Murphy 1990; Smith and Watts 1992; Bushman Indjejikian, and Smith 1996). This finding also reveals the need for the control variable for regulatory environment in our empirical models. We thank our reviewer for the suggestion to control for regulatory environment.

To estimate the relation between CEO cash compensation and earnings performance, some studies estimate firm-specific regressions (e.g., Antle and Smith 1986; Healy, Kang, and Palepu 1987; Lambert and Larcker 1987; Defeo, Lambert, and Larcker 1989; Dechow, Huson, and Sloan 1994) and others estimate a regression for the pooled (cross-sectional and time-series) data set (e.g., Murphy 1985; Jensen and Murphy 1990; Ely 1991; Baber, Janakiraman, and Kang 1996). The pooled regression model constrains the CEO compensation-performance sensitivity to be identical across firms, and it ignores potential cross-firm variation in economic factors that likely affect the relation between CEO compensation and firm performance. With a heterogenous sample of firms, the potential bias using pooled cross-sectional data could be severe and lead to incorrect inferences with respect to the relation between CEO compensation and firm performance. Even in the utility industry, there is considerable variation in firm characteristics and operating environments (Bryan and Hwang 1997). However, this variation is less likely to be a concern compared to a multi-industry sample. Further, as a practical matter, our short time series, especially in the regulated period (1990–92) limits our research design to the pooled methodology, using panel data. However, since firms of differing sizes are included in the pooled regression, we use percentage changes in CEO cash compensation and earnings to mitigate the potential effect of firm size on the cash compensation-earnings sensitivity.[16]

With respect to stock option compensation, we construct a $\mathrm{Mix}_{\mathrm{option}}$ variable, measured as the ratio of stock option compensation to cash compensation, as follows:

$$\mathrm{Mix}_{\mathrm{option}} = (\mathrm{Option}_{\mathrm{Black\text{-}Scholes}} \times \text{Number of options granted})/(\text{Salary plus bonus})$$

In measuring the relative use of CEO stock option awards to cash compensation (Mix), we use the Black-Scholes option value.

16. In our pooled regressions with fixed year effects, regression residuals are positively correlated over time, thereby overstating reported statistical significance on our independent variables. To examine the effect of the serial correlation in the residuals, we also perform cross-sectional regressions for each of the years during the test period between 1990–2001. The results using these year-by-year regressions are very similar to those reported in the text and hence not reported. We also estimated a single model with period dummies, rather than separate regressions for each period. The conclusions that we drew are identical to what is reported in the paper. We also estimated models using first differences instead of percent changes. The conclusions that we drew are identical to what is reported in the paper. One variation on the gross margin model (Model 2), however, is noteworthy. When we scale gross margin by sales, which measures the “gross margin ratio,” our results are weaker. Further analysis reveals that the diminished association between cash compensation and the gross margin ratio is driven by data in years 2000 and 2001, corresponding to years with the highest cost ratios ($1 - \mathrm{GM}$ ratio), as will be shown in table 2.

The stock option compensation model (without firm and year subscripts) is

$$\text{Model 5: } \text{Mix}_{\text{option}} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + b\text{FCF} + c\text{Lev} + d\text{IOS} + e\text{SIZE} + f\text{OWN} + g\text{Regenv} + \varepsilon,$$

where

$\sum_{t=\text{Begin}}^{\text{End}}$ Years = Indicator variables for the years in the respective sample periods, either 1990–92 or 1993–2001;
FCF = free cash flow (our liquidity proxy) measured as operating income before depreciation, less the sum of income tax, interest and dividends paid, scaled by market value;[17]
Lev = long-term debt outstanding plus long-term debt in current liabilities scaled by total assets (our leverage proxy);
IOS = investment opportunity set, measured as market value of equity scaled by book value of equity;[18]
SIZE = natural log of total assets;
OWN = managerial stock ownership;
Regenv = indicator variable for regulatory environment.

In addition to the hypothesized explanatory variables, we include year-indicator variables to control for the fixed year effects. We also include OWN as a control variable. When CEOs hold a large fraction of their firms' equity, the demand for further stock-based compensation is reduced, since the agency costs of equity are less severe (Jensen and Meckling 1976). Also, since CEOs are typically unable to diversify away the risk

17. We use FCF as a proxy for liquidity constraints, similar to Bryan et al. 2000. We acknowledge the use of FCF as a proxy for other attributes that may affect stock option compensation. For instance, earlier studies examine the corporate control environment of the 1980s. Asquith and Wizman (1990), Crabbe (1991), and Cook and Easterwood (1994) describe the wealth losses that bondholders suffer following, for example, leveraged buyouts and major capital restructurings. Lehn and Poulsen (1989) find that firms with more free cash flow have significantly higher probabilities of engaging in these leverage-increasing transactions, because the debt incurred from the transaction reduces the free cash flow problem. Since higher free cash flow indicates a greater likelihood of a leverage-increasing event, we expect a negative relation between free cash flow and the use of stock option compensation to mitigate the agency cost of debt. For both arguments, free cash flow provides an indication of liquidity and the expected sign is negative. In addition, it is possible that FCF captures an aspect of a firm's investment opportunity set to the extent that firms with a rich investment opportunity set have low FCF. We thank the reviewer for this point.

18. In addition to market to book equity as the proxy for IOS, we use market to book assets, consistent with Smith and Watts (1992), Yermack (1995), and Gaver and Gaver (1993). The results using this measure are qualitatively similar to the results reported in the paper and are not given.

associated with their wealth, because their human capital is tied to a single position of employment (Smith and Watts 1992), CEO's are unlikely to tolerate additional risk from equity compensation. As before, as the proxy for CEO stock ownership, we use the percentage of CEO stockholdings. In addition, we control for regulatory environment (Regenv). As the proxy for Regenv (as before) we use an indicator variable that equals 1 if the number of lines of business identified in Compustat's Business Segment file is two or more.

Not all firms grant CEO stock options or restricted stock every year (Yermack 1995). Therefore, we test Model 5 using a Tobit model because of the preponderance of left-censored (at zero) stock option compensation. Further, we report the Tobit regression results using panel data, instead of estimating the model year by year, to utilize all available information relating to year-to-year variation.[19]

IV. Descriptive Statistics and Empirical Results

A. Descriptive Statistics

Table 1 gives mean values of firm characteristics for each year of the sample period. Total firm year observations equal 893. Data availability on CEO compensation in proxy statements and on component-level data in FERC Form 1 affects the year to year sample sizes. PROF1 and PROF2 are two earnings-based measures of performance, both of which we scale by total assets. Earnings before interest, taxes, depreciation, and amortization (EBITDA) is the performance measure for PROF1, and earnings before extraordinary items represents the performance measure for PROF2. Both performance measures remain fairly stable for most of the decade, until 1998, when PROF1 dips to 11.1% and PROF2 dips to 3.0% and both decline further going forward until the end of the sample period. The free cash flow metric, scaled by market value, shows a similar stable pattern until 1996 when it rises to 4.1%, then falls to 3.2% by the end of the decade. Leverage, scaled by total assets, increases over the decade rising to 64.7% by the end of the sample period. The investment opportunity set (IOS) ranges from 1.158 in 1990 to 2.029 in 1995 and falls to a range from 1.550 (1996) to 1.786 (2000). Size increases steadily over the decade. Both the variance of earnings, scaled by total assets, and the variance of monthly stock returns fall slightly from the early part of the decade to the middle of the decade but increase toward the end of the sample period. Overall, the picture shows an industry experiencing increasing leverage and size and decreasing profitability in the latter years of the 1990s, particularly 1999 and

19. Furthermore, conducting the analysis year by year likely produces high standard errors, since it ignores the information from the remainder of the sample.

TABLE 1 **Mean Values* of Utility Industry Characteristics (SIC Codes 4911 and 4931) over the 1990–2001 Period**

Variable	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
No. firms	64	72	78	79	79	81	80	79	77	72	70	62
PROF1	.122	.116	.119	.113	.121	.121	.122	.116	.111	.109	.108	.109
PROF2	.035	.031	.034	.031	.034	.036	.036	.032	.030	.030	.028	.029
FCF	.035	.033	.033	.033	.034	.038	.041	.035	.036	.036	.032	.034
Lev	.574	.581	.585	.600	.607	.605	.608	.616	.629	.643	.614	.647
IOS	1.158	1.493	1.353	1.378	1.078	2.029	1.550	1.612	1.670	1.413	1.786	1.628
Size	7.764	7.818	7.908	7.982	7.986	8.048	8.105	8.202	8.307	8.419	8.522	8.738
Vearn	.0018	.0037	.0008	.0005	.0002	.0002	.0002	.0003	.0003	.0003	.0006	.0101
Vret	.0065	.0063	.0097	.0038	.0041	.0029	.0033	.0051	.0070	.0087	.0165	.0210

NOTE.—

PROF1 = Earnings before interest, taxes, depreciation and amortization (EBITDA) scaled by total assets.
PROF2 = Earnings before extraordinary items scaled by total assets.
FCF = Free cash flow, measured as operating income before depreciation, less the sum of income tax, interest and dividends paid, scaled by market value.
Lev = Leverage long-term debt outstanding plus long-term debt in current liabilities scaled by total assets.
IOS = Investment opportunity set, measured as market value of equity scaled by book value of equity.
Size = Natural log of total assets.
Vearn = Variance of annual earnings before extraordinary items scaled by total assets.
Vret = Variance of monthly stock returns.

* Cross-sectional means, except for Vearn and Vret.

TABLE 2 **Mean Values of Electric Utilities' Measures of Operation and Maintenance Expense by Year (Data are from Annual FERC Form 1 Filings)**

Variable	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Changes in Total and Components of Operation and Maintenance Expense												
O&M/OPREV	.6298	.6302	.6298	.6296	.6261	.6059	.6239	.6304	.6372	.6597	.6943	.7062
PROD/O&M	.7425	.7390	.7388	.7302	.7259	.7257	.7244	.7170	.7216	.7342	.7276	.7427
PUR/O&M	.2374	.2491	.2496	.2813	.2892	.3029	.3119	.3363	.3442	.3975	.4457	.4106
TRDIST/O&M	.0875	.0872	.0859	.0847	.0840	.0827	.0837	.0841	.0879	.0891	.1055	.1021
CUST/O&M	.0488	.0503	.0501	.0504	.0521	.0554	.0546	.0569	.0560	.0515	.0455	.0472
ADMIN/O&M	.1215	.1235	.1266	.1343	.1380	.1361	.1373	.1418	.1344	.1250	.1212	.1074
Changes in Power Produced and Power Purchased												
GEN/PROD	.6934	.6518	.6425	.6164	.5965	.5764	.5656	.5535	.5041	.4424	.3966	.3365
GENPW/POWER	.7533	.7113	.6986	.6791	.6759	.6573	.6384	.6315	.6182	.5439	.5091	.4523
PUR/PROD	.3155	.3334	.3401	.3805	.3948	.4125	.4269	.4541	.4759	.5401	.5855	.5935
PURPW/POWER	.2412	.2678	.2968	.3180	.3191	.3289	.3588	.3517	.3967	.4514	.5131	.5126
Changes in the Number of Employees and Labor Cost												
NEMP	5,270	4,861	4,744	4,718	4,207	4,419	3,863	3,587	3,301	3,184	3,073	2,886
OPREV/NEMP	384.76	403.97	41.59	455.6	497.78	527.52	564.73	742.33	753.07	686.97	779.04	796.42
LABOR/OPREV	.0834	.0828	.0819	.0823	.0803	.0795	.0766	.0742	.0678	.0760	.0673	.0573
LABOR/O&M	.1601	.1572	.1587	.1574	.1539	.1535	.1479	.1407	.1249	.1402	.1200	.0962
PRODLAB/O&M	.0615	.0595	.0629	.0607	.0589	.0590	.0545	.0624	.0409	.0442	.0388	.0291
TRDISTLAB/O&M	.0403	.0391	.0385	.0382	.0378	.0369	.0355	.0363	.0295	.0339	.0326	.0316
CUSTLAB/O&M	.0232	.0224	.0225	.0228	.0225	.0225	.0210	.0221	.0171	.0175	.0164	.0155
ADMLAB/O&M	.0349	.0339	.0346	.0358	.0348	.0351	.0325	.0343	.0205	.0317	.0305	.0260

NOTE.—

O&M/OPREV = operation and maintenance expenses scaled by operating revenue.
PROD/O&M = operation and maintenance expenses for the production of electricity, including purchased power expenses, scaled by total operation and maintenance expenses.
PUR/O&M = purchased power expenses from independent power producers and other power generators scaled by total operation and maintenance expenses.
TRDIST/O&M = transmission and distribution expenses scaled by total operation and maintenance expenses.
CUST/O&M = customer-related expenses including customer accounts and customer services scaled by total operation and maintenance expenses.
ADMIN/O&M = administrative and general expenses scaled by total operation and maintenance expenses.
GEN/PROD = operation and maintenance expenses for power generation (excluding purchased power expenses), scaled by production, operation, and maintenance expenses.
GENPW/POWER = generated power in terms of kilowatt hours scaled by total power produced, including purchased power in kilowatt hours.
PUR/PROD = purchased power expenses from independent power producers and other power generators, scaled by production operation and maintenance expenses.
PURPW/POWER = purchased power from independent power producers and other power generators in kilowatt hours scaled by total power produced, including purchased power in kilowatt hours.
NEMP = number of employees.
OPREV/NEMP = operating revenue scaled by number of employees (in 000s).
LABOR/OPREV = total labor expenses scaled by operating revenue.
LABOR/O&M = total labor expenses scaled by total operation and maintenance expenses.
PRODLAB/O&M = labor expenses related to power production activities scaled by total operation and maintenance expenses.
TRDISTLAB/O&M = labor expenses related to power transmission and distribution activities scaled by total operation and maintenance expenses.
CUSTLAB/O&M = labor expenses related to customer-related activities scaled by total operation and maintenance expenses.
ADMLAB/O&M = labor expenses related to administration and general activities (ADMLAB) scaled by total operation and maintenance expenses.

2000. These years are also marked by increased earnings and stock return volatility relative to the earlier years in our sample.

Table 2 gives mean values by year of internal expense measures. We focus mainly on O&M expenses (operation and maintenance) for the firm as a whole and then by functional area (generation, transmission, and retail). O&M scaled by operating revenue is 62.98% in 1990. O&M/OPREV falls to 60.59% in 1995 before rising for the remaining years of the 1990s and peaking at 70.62% in year 2001. Production O&M as a percent of total O&M is 74.25% in 1990 and remains in a range of about 71% to 74% for the remainder of the decade, reaching 74.27% in 2001. Production O&M includes purchased power. Thus, we separate purchased power from production O&M as PUR/O&M. This metric grew from 23.74% in 1990 to 44.57% in 2000 before falling to 41.06% in 2001. This evidence corroborates the expected increased outsourcing of power. Transmission O&M as a percent of total O&M is stable in the mid-8% range, until peaking at 10.55% in year 2000.

The number of employees fell from an average of 5,270 employees to 2,886 in 2001. The associated amount spent on labor as a percent of operating revenue fell from 8.34% to 5.73% and, as a percent of total O&M fell from 16.01% to 9.62% from the beginning to the end of the sample period. Labor reductions appear to come primarily from the production function: PRODLAB/O&M fell from 6.15% down to 2.91% over the sample period.

In table 3, we show the results of tests of differences of the measures reported in tables 1 and 2. Panel A reveals a significant decrease in PROD/O&M and a significant increase in PUR/O&M as suggested by the underlying yearly data (table 2). Also, the dramatic drop in the number of employees (NEMP) and the related rise in the amount of operating revenue per employee (OPREV/NEMP) is reflected in the significance levels (*t*-statistics of -2.95 and 3.89, respectively, as shown in panel C). The major labor components as a percent of total O&M also fell significantly, except for the means of customer-related and administration expenses. Panel D shows that the increases in leverage and size from the regulated to the deregulated periods are statistically significant at the 1% level, consistent with the yearly time series data.

Table 4 provides the descriptive statistics of utility CEO compensation components. The magnitude of salary (in 2001 dollars) increased 101% (from \$327.48 thousand in 1990 to \$659.02 thousand in 2001). Bonuses rose by a factor of 6.3 (from \$100.07 thousand to \$627.50 thousand) and option compensation by a factor of 31.4 (from \$27.94 thousand to \$878.42 thousand). The $\text{Mix}_{\text{option}}$ variable (ratio of option compensation to salary plus bonus) rose by a factor of 12.4 (from 0.058 to 0.721), indicating a significant shift to equity-based pay. We observe similar increases for restricted stock awards and long-term incentive plan payouts (LTIP).

TABLE 3 **Changes in Internal Efficiency Measures and Firm Characteristics from the 1990–1992 Period to the 1993–2001 Period for Electric Utilities**

Variable	Mean for 1990–92	Mean for 1993–01	*t*-Statistics	*Z*-Statistics
A. Changes in Total and Components of Operation and Maintenance Expense (O&M)				
O&M/OPREV	.631	.646	1.62	.43
PROD/O&M	.740	.728	−2.02**	−6.03***
PUR/O&M	.246	.347	4.28***	8.41***
TRDIST/O&M	.087	.089	−1.30	1.22
CUST/O&M	.047	.052	2.15**	6.29***
ADMIN/O&M	.122	.131	2.84***	5.98***
B. Changes in Power Produced and Power Purchased				
GEN/PROD	.668	.510	−4.88***	−5.66***
GENPW/POWER	.722	.601	−4.48***	−5.01***
PUR/PROD	.328	.474	4.68***	4.92***
PURPW/POWER	.269	.394	4.77***	5.44***
C. Changes in the Number of Employees and Labor Cost				
NEMP	4,924	3,693	−2.95***	−3.42***
OPREV/NEMP (000s)	398.43	644.21	3.89***	6.51***
LABOR/OPREV	.083	.073	−3.39***	−3.83***
LABOR/O&M	.159	.137	−3.17***	−3.55***
PRODLAB/O&M	.061	.050	−2.42**	−3.17**
TRDISTLAB/O&M	.039	.035	−2.12**	−3.17***
CUSTLAB/O&M	.023	.020	−1.27	−2.21**
ADMLAB/O&M	.035	.031	−1.53	−2.13**
D. Changes in Firm Performance and Economic Characteristics				
PROF1	.119	.114	−1.62	−2.82**
PROF2	.031	.030	−.19	−2.69**
FCF	.034	.035	.41	1.92*
Lev	.579	.619	3.89***	4.88***
IOS	1.336	1.572	1.44	3.71***
Size	7.828	8.257	3.90***	4.16***

***, **, * Statistically significant at the 1%, 5%, 10% level based upon two-tailed tests. Please refer to tables 1 and 2 for data definitions.

Table 5 documents the statistical significance of changes in compensation structure from the regulated to the deregulated periods. Panel A shows the results for utility firms. The magnitudes of all five major components of CEO compensation increased significantly (at the 1% level) from the earlier to the later time periods. For instance, the mean bonus rose by a factor of almost 3, from $108.450 to $316.014 thousand, and the mean value of options rose by a factor of almost 7, from $42.485 to $288.913 thousand. These increases are underscored in the mean of the proportions, also given in panel A of table 5. Of particular interest, the proportion of salary dropped from a mean of 61.7% to a mean of 35.0% with a corresponding increase in the proportion of incentive-based compensation from a mean of 38.3% to a mean of 66.1%. Focusing on the

TABLE 4 **Mean Values of Utility Industry (SIC Codes 4911 and 4931) CEO Compensation Components over the 1990–2001 Period (All Dollar Figures in thousands of 2001 Dollars)**

Variable	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Salary	$327.48	$358.19	$412.22	$424.31	$433.91	$453.45	$465.40	$532.95	$582.06	$594.25	$619.85	$659.02
Bonus	100.07	104.85	116.17	150.19	149.60	211.34	235.23	236.52	353.42	410.47	559.84	627.50
Option	27.94	29.25	36.29	40.39	39.15	31.15	29.16	90.40	212.39	426.53	672.62	878.42
Restricted	16.85	23.46	86.62	37.36	50.68	73.20	89.24	148.23	226.59	258.24	366.47	497.55
LTIP	33.14	31.13	46.63	58.84	40.42	89.34	92.65	139.10	200.12	189.42	393.98	233.66
Mix_{option}	.058	.048	.064	.066	.064	.043	.047	.131	.258	.465	.626	.721

NOTE.—

Salary = CEO salary.
Bonus = CEO bonus.
Option = CEO stock-option compensation measured using the Black-Scholes option pricing model.
Restricted = CEO restricted-stock compensation.
LTIP = CEO long-term incentive plan payout.
Mix_{option} = Ratio of CEO stock option compensation (option) to cash compensation (salary plus bonus).

TABLE 5 Changes in Compensation from the 1990–92 Period to the 1993–2001 Period for Electric Utilities and Control Firms

Variable	Mean for 1990–92	Mean for 1993–2001	*t*-Statistics	*Z*-Statistics
A. Electric Utility Firms				
Salary	367.241	543.504	8.87***	8.32***
Bonus	108.450	316.014	8.17***	8.59***
Option	42.485	288.913	6.49**	8.08***
Restricted	50.381	191.516	3.98**	3.47***
LTIP	35.957	157.712	2.57***	4.66***
Proportion salary	.617	.350	−5.98***	−6.95***
Proportion incentive	.383	.661	6.55***	8.40***
Proportion equity	.124	.333	8.48***	6.43***
$\mathrm{Mix}_{\mathrm{option}}$	.056	.292	4.63***	6.66***
B. Control Firms				
Salary	624.671	651.211	1.87*	2.66**
Bonus	343.991	510.001	4.12***	5.33***
Option	1402.661	1850.446	2.72***	2.07**
Restricted	236.439	342.961	1.60	1.84
LTIP	134.228	333.444	5.15***	6.22***
Proportion salary	.225	.175	−2.14*	−2.42**
Proportion incentive	.771	.828	2.11*	2.60**
Proportion equity	.592	.598	.98	1.13
$\mathrm{Mix}_{\mathrm{option}}$	1.43	1.57	1.86*	2.32**

NOTE.—

Salary = CEO salary.
Bonus = CEO bonus.
Option = CEO stock-option compensation measured using the Black-Scholes option pricing model.
Restricted = CEO restricted stock compensation.
LTIP = CEO long-term incentive plan payout.
Proportion salary = Salary as percentage of total compensation.
Proportion incentive = Sum of bonus, option, restricted, and LTIP as proportion of total compensation.
Proportion equity = Sum of option and restricted as proportion of total compensation.
$\mathrm{Mix}_{\mathrm{option}}$ = Ratio of CEO stock option compensation (option) to cash compensation (salary plus bonus).

ratio of stock option compensation to cash compensation, Mix rose significantly from 5.6% to 29.2%. Altogether, we document significant shifts to incentive-based compensation, consistent with our expectations. All forms of incentive-based compensation increased, but the largest changes concerned equity-based compensation.

The results for the control sample are presented in panel B of table 5. The magnitude of salary increased marginally and restricted stock did not increase significantly. The magnitude of bonus and option did increase significantly, but related proportions changed marginally or insignificantly, relative to those for utilities. For instance, control firms' proportion salary, decreased from 22.5% to 17.5% ($t = -2.14$) and the proportion incentive rose from 77.1% to 82.8% ($t = 2.11$). These compare to the utility industry's change in proportion salary from 61.7% to 35.0% ($t = -5.98$) and change in proportion incentive from 38.3% to 66.1%. Further, the control firms' proportion equity did not change significantly, increasing only from 59.2% to 59.8% ($t = 0.98$), but the same proportion for utility firms increases by a factor of almost 3 (from 12.4% to 33.3%; $t = 8.48$).

These results show that the changes for utility firms are of several orders of magnitude higher than those for the control firms and, therefore, likely attributable to the differences in the regulatory status of the two samples. The results are also consistent with theory. In the utility industry, the requirement for incentive compensation is lessened under regulation, since direct monitoring serves to reduce agency costs of equity. During deregulation, the need for incentive compensation increases due to reduced regulatory oversight, not only in the utility segment, but also in new segments into which utility firms are now allowed to venture. This latter point also underscores the need for increased stock-option compensation to induce risk-taking behavior into such new ventures.

B. Empirical Results for Cash Compensation

Table 6 provides the results for our cash compensation models (Models 1–4). Model 1 includes the percentage change in accounting earnings (annual earnings before extraordinary items and discontinued operations); Model 2 includes the percentage change in gross margin. Model 3 includes the percentage change in O&M (operation and maintenance expenses from FERC Form 1), and Model 4 includes the percentage changes in the components of O&M: production O&M (PrO&M), transmission O&M (TrO&M), and retail O&M (RetO&M). All models contain year indicator variables and all models contain controls for managerial ownership and for the severity of the regulatory environment.

The results indicate that the percentage change in earnings is insignificantly associated with percentage changes in cash compensation in the 1990–92 period (Model 1a, $b = -0.012$, $t = -0.058$). However, the relation becomes significant at the 1% level during the 1993–2001 period (Model 1b, $b = 0.044$; $t = 5.72$). This result indicates a strong link between CEO cash compensation and firm-level earnings during the deregulated period, in accordance with the prediction that executive pay would become more performance based, after controlling for year effects, ownership, and regulatory environment.

We next test whether component-level performance measures are significant determinants of CEO cash compensation. Our tests are guided by the fact that the acclaimed benefits of deregulation are improvements in efficiency at the operating level of electric utilities. Thus, we consider whether component-level gross margin and component-level expenses (O&M) explain CEO cash compensation.

Unlike our previous firm-level earnings results, our component-level gross margin results are not significant in either the regulated period (Model 2a) in the deregulated period (Model 2b). The estimate of the coefficient on the gross margin variable in the deregulated period is 0.021 ($t = 1.27$). This result is contrary to our expectation that the percentage change in cash compensation would be more closely tied to component-level gross margin performance.

When we further refine our tests by considering major expense categories and subcategories (PrO&M, TrO&M, and RetO&M), we continue to be unable to detect significant relations. The results of the Models 3 and 4 do not indicate any significant relation between changes in cash compensation and changes in internal expense measures during either time period. For instance, the coefficient on O&M in Model 3b is -0.016, $t = -1.28$.

These results, taken together, suggest that the determinants of CEO cash compensation during the deregulated period are firmwide earnings but not changes in any of the component-level metrics. The significance of the firmwide changes in accounting earnings is expected, since it best reflects the CEO's corporatewide span of responsibility. The explanatory power of firmwide earnings is corroborated anecdotally (Appendix F) in Duke Energy's 2000 proxy statement. However, the finding that CEO compensation is not associated with component-level results is contrary to expectations.

C. *Empirical Results for Stock Option Compensation*

We test the relation between $\text{Mix}_{\text{option}}$ (the ratio of stock-option compensation, measured with the Black-Scholes model, to cash compensation) and proxies for economic determinants shown to be significant from previous studies (Yermak 1995; Bryan et al. 2000). Our interest is driven by the fact that $\text{Mix}_{\text{option}}$ is 0.058 in 1990 and it rises to 0.721 in 2001 (table 4).

Our results are presented in table 7. The results of Model 5 show that FCF and IOS are significant determinants of stock option compensation relative to cash compensation in the regulated period (1990–92, Model 5a). In the deregulated period, FCF, Lev, IOS, and SIZE are significant. The signs are as expected. FCF is negatively related to $\text{Mix}_{\text{option}}$ for both periods, suggesting that the lower is the liquidity (FCF), the greater the relative use of options. Additionally, the negative relation may reflect the degree of event risk, suggesting that firms with higher free cash flow, which are more likely to engage in leverage increasing activities, use less option compensation (Lehn and Poulsen 1989).

TABLE 6 Cash Compensation Models

Model (Period)	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	Adj. R^2
A. Ordinary Least Squares OLS Regressions of Percent Changes in CEO Cash Compensation on Percent Changes in Firm-Level and Component-Level Performance Measures for both the 1990–92 Period (90–92) and the 1993–2001 Period (93–01)									
1a (90–92)	−.012						−.032	.091	7.12%
	(−.058)						(−1.79)	(.30)	
1b (93–01)	.044						.006	.130	12.55%
	(5.72)***						(.59)	(.65)	
2a (90–92)		.010					−.033	.154	7.87%
		(.14)					(−1.81)	(.56)	
2b (93–01)		.021					.005	.091	5.72%
		(1.27)					(.54)	(.39)	
3a (90–92)			−.003				−.036	.072	11.31%
			(−.08)				(−1.95)*	(.62)	
3b (93–01)			−.016				.004	.083	4.19%
			(−1.28)				(.64)	(.38)	
4a (90–92)				.064	.027	−.039	−.020	.261	5.53%
				(.26)	(1.08)	(−1.57)	(−1.04)	(.86)	
4b (93–01)				.011	−.014	.055	.009	.120	3.88%
				(.32)	(−.96)	(.99)	(.57)	(.39)	

B. Estimates of Models 2b and 3b with years 1999, 2000, and 2001 Omitted. (Sample size is 472)					
2b (93–98)	.146		−.010	.096	
	(6.03)***		(1.04)	(.61)	11.12%
3b (93–98)		−.039	−.005	.078	5.72%
		(−2.01)*	(.74)	(.88)	

Note.—The data in panel A are pooled cross-sectional and time series. The number of observations are 136 and 664 for the earlier and later periods, respectively. Heteroscedastic adjusted t-statistics are in parentheses. Fixed effects are incorporated by year indicator variables for respective years of each time period. Compensation data are inflation adjusted.

Model 1: $\%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + b(\%\Delta\text{AccE}) + h\text{OWN} + i\text{Regenv} + \varepsilon.$

Model 2: $\%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + c(\%\Delta\text{GM}) + h\text{OWN} + i\text{Regenv} + \varepsilon.$

Model 3: $\%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + d(\%\Delta\text{O\&M}) + h\text{OWN} + i\text{Regenv} + \varepsilon.$

Model 4: $\%\Delta\text{Cashcomp} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + e(\%\Delta PrO\&M) + f(\%\Delta\text{TrO\&M}) + g(\%\Delta\text{RetO\&M}) + h\text{OWN} + i\text{Regenv} + \varepsilon.$

Cashcomp = CEO’s cash compensation (salary plus bonus).
AccE = Annual earnings before extraordinary items and discontinued operations.
GM = Operating revenue less operation and maintenance expense.
O&M = Total operation and maintenance expenses as reported on FERC Form 1.
PrO&M = Production-related O&M.
TrO&M = Transmission-related O&M.
RetO&M = Retail-related O&M.
OWN = Managerial stock ownership.
Regenv = Indicator variable for regulatory environment; Regenv = 1 if the number of lines of business identified in Compustat’s Business Segment file is two or more; 0 otherwise.

TABLE 7 Mix of CEO Option Compensation to Cash Compensation

Model (period)	*b*FCF	*c*Lev	*d*IOS	*e*SIZE	*f*OWN	*g*Regenv	No. Censored/ Noncensored
5a (90–92)	−1.589	−.747	.157	.066	.005	−.112	130/69
	(2.63)*	(2.17)	(3.98)**	(2.18)	(.62)	(.31)	
5b (93–01)	−6.001	−4.98	.486	.291	.010	.635	335/329
	(3.43)**	(4.39)**	(8.41)***	(10.88)***	(1.01)	(3.74)**	

NOTE.—These are Tobit regressions of CEO Mix of option compensation to cash compensation (Mix_{option}) on economic determinants. Chi-square statistics in parentheses. Fixed effects are incorporated by year indicator variables for respective years of each time period. Compensation data are inflation adjusted.

$$\text{Model 5: } Mix_{option} = \sum_{t=\text{Begin}}^{\text{End}} \text{Years} + b\text{FCF} + c\text{Lev} + d\text{IOS} + e\text{SIZE} + f\text{Own} + g\text{Regenv} + \varepsilon.$$

Mix_{option} = Ratio of CEO stock option compensation (option) to cash compensation (salary plus bonus).
FCF = Free cash flow, measured as operating income before depreciation, less the sum of income tax, interest, and dividends paid, scaled by market value.
Lev = Long-term debt outstanding plus long-term debt in current liabilities scaled by total assets.
IOS = Investment opportunity set, measured as market value of equity scaled by book value of equity.
SIZE = Natural log of total assets.
OWN = Managerial stock ownership.
Regenv = Indicator variable for regulatory environment; Regenv = 1 if the number of lines of business identified in Compustat's Business Segment file is two or more; 0 otherwise.

Firm leverage is significantly, negatively related to stock option compensation. This result is consistent with earlier research, which shows leverage is a significant determinant that is negatively associated with stock option awards, since option compensation in highly leveraged firms would exacerbate the agency cost of debt. The investment opportunity set is significantly positive for both periods, but the level of significance is greater during the period of deregulation. The positive sign reflects the information asymmetry of firms with relatively higher growth options and the need to induce managers to take action to exploit these growth options.

The SIZE variable becomes a significant explanatory variable in the deregulated period. This would suggest that the information asymmetry increases in firm size, and to align the interest of managers and shareholders, more equity-based pay is required, including stock-options. The fact that both IOS and SIZE become more significant in explaining stock option compensation in the deregulated period likely reflects the significant increases in both measures from the regulated to the deregulated period, according to table 3.

D. Sensitivity Analysis for CEO Cash Compensation and O&M Expense

From table 2, we note the steady improvement (reduction) in operation and maintenance expenses, scaled by operating revenue, from the beginning of the decade to the middle of the decade. This measure, O&M/OPREV, a cost-ratio metric, falls to a low of 60.59% in 1995, then monotonically increases throughout the remainder of the decade. We also note that the proportion of power generated (GEN/PROD) decreases steadily throughout the decade and the proportion of power purchased (PUR/PROD) increases. Taken together, these statistics suggests that the initial outsourcing of power, along with reductions in personnel, improved the utilities' operating margins at the component level. However, changes in the power cost structure toward the end of the decade offset the earlier improvements in the O&M/OPREV performance metric. For example, Appendix G shows the rapid increase in natural gas prices beginning around 1999. Thus, a conundrum of rising cash compensation over the latter part of the decade and falling performance (O&M/OPREV) over the same period, suggests a possible disconnection between CEO cash compensation and O&M. Therefore, we retest the relation between percentage changes in CEO cash compensation and percentage changes in both GM and O&M, omitting the years 1999, 2000, and 2001.

Our results are presented in table 6, panel B. We find that the relation between the percentage change in CEO cash compensation and the percentage change in gross margin is significantly positive. We also find that the relation between percentage changes in CEO cash compensation and percentage changes in operation and maintenance expenses is significantly negative. For instance, the coefficient estimate for O&M is -0.039 ($t = -2.01$, which is significant at 10% level). The results of the other relations (between cash compensation and expense components) remain qualitatively the same as those reported in table 6 when we omit the final 3 years of the sample period. This evidence suggests that CEO cash compensation is significantly positively associated with gross margins and significantly negatively associated with operation and maintenance expenses in the period immediately after deregulation, up to year 1998. However, since the results in table 6, panel A, with respect to gross margins and operation and maintenance expenses suggest no relation, the observations from 1999, 2000, and 2001 likely diminish the associations as measured over the entire period, from 1993 to 2001.

One possible conclusion to draw is that firms delinked CEO cash compensation from changes in operation and maintenance expense in these latter years, which are marked by significant increases in O&M. Factors that may have led firms to alter their compensation schemes include increased competition in the labor markets and concomitant concerns over retention. For instance, Cumming (1999) suggests that compensation for electric utility CEOs still lags that of counterparts in general industry. Also, some firms appear to be changing the composition of their "peer group" for setting CEO compensation. For example, FPL Group, in its 1999 proxy, discloses:

> The Committee determines an executive's competitive total level of compensation based on information drawn from a variety of sources, including utility and general industry surveys, proxy statements, and independent compensation consultants. The Corporation's "comparator group" consists of nine electric utilities (all but one of which are included in the Dow Jones Electric Utilities Index), five telecommunications companies, and six general industrial companies located in the Southeast. Emerging electric utility industry trends (i.e., deregulation and increasing competition) and the need to recruit from outside the industry are the principal reasons for including companies other than electric utilities in the comparator group.

Finally, we note how some firms explicitly changed their bonus formulas. For instance, OGE reported the following changes in bonus formula parameters from 1999 to 2001:

Year	EPS	O&M	EBIT	"Other"
Year 2001	50.0%	25.0%	25.0%	
Year 2000	45.0%	22.5%	22.5%	10.0%
Year 1999	50.0%	50.0%		

Notably, the bonus formula weighting on O&M dropped from 50.0% to 22.5% from year 1999 to year 2000, rising slightly to 25% for year 2001. We also note from our FERC Form-1 data that OGE's cost ratios (O&M/OPREV) for years 1999, 2000, and 2001 respectively, were, as follows: 66.31%, 72.33%, 70.15%. The reason for the changes in the cost ratio is not clear. Press reports suggests that some utilities reallocated expenses from unregulated divisions to regulated divisions to exploit cost reimbursement (through electricity rates charged to consumers) and avoid earning more than PUC-allowed rates of return (Smith 2002). Another contributing factor to the increase in the cost ratio for some utilities could be the rise in fuel cost, as noted in Appendix G, which shows that natural gas wellhead prices peaked to about $8 per million cubic feet toward the end of 2000.

Future research may wish to attempt to determine whether these changes suggest a systematic shift to alternative performance measures, perhaps even to the extent of extracting labor market rents, when macroeconomic factors deteriorate. For instance, Kranhold (1999) quotes the Duke Energy human resource vice president: "We are looking at new compensation, retention compensation, and attraction compensation. All of that is occurring at a pace that 12 months ago I would have said was unsustainable." If this shift is systematic, then the changes in compensation more likely reflect labor market conditions rather than firm performance in these latter years of our sample.

V. Conclusions

The 1992 National Energy Policy Act intensified competition in the electric utility industry by allowing nonutility generators to produce and sell power in the wholesale energy markets. One anticipated result of increased competition was an improvement in efficiency. Although we study multiple measures of efficiency, our primary focus is on CEO compensation structure and whether it became more incentive based subsequent to deregulation in order to effect the efficiency improvements hoped for under deregulation. Specifically, we test whether the relation between CEO cash compensation and firm performance and between CEO stock-option compensation and firm characteristics strengthen during the deregulated period.

We found that firms made significant operational changes, such as outsourcing power production and reducing the number of employees and labor cost. However, the initial improvements in operating efficiencies, as measured by various cost measures, were not sustained throughout the entire sample period. We found that incentive-based forms of pay did increase significantly, and we document a significant association between incentive-based compensation and firm performance during the period immediately after deregulation. However, for the entire deregulated period, the association becomes insignificant. The insignificant pay-performance association during entire sample period suggests a delinking of pay to performance during the most recent years, which correspond to worsening firm performance. Finally, we find that equity-based compensation also increased significantly, and we document a significant association with theorybased determinants during the deregulated period.

Generally, consistent with the predictions of agency theory, we find that the substitution of market forces for monitoring led to an increase in incentive-based compensation, tied initially to accounting-based performance measures, and an increase in equity-based compensation. The surprising result, however, and the basis for future research, is the apparent disconnection or (in some instances, overt) reweighting of the parameters of bonus formulas that certain utilities undertook during worsening performance.

Appendix A

Electric Utilities as a Natural Monopoly

Electric utilities historically have been vertically integrated, engaging in the generation, wholesale, transmission, and retail of electricity. Because utilities are viewed as natural monopolies, they have been subject to federal and state regulations. On the federal level, the Federal Energy Regulatory Commission, established in 1977, regulates the wholesale electricity market (i.e., the sale and service of interstate power and transmission) both among utilities and between utilities and nonutility generators. On the state level, state public utility commissions regulate utilities' prices, capital investments, and retail services to homes, businesses, and industries.

Two relevant state-regulatory actions pertain to rate-of-return regulation and approvals for the construction of new generation and transmission facilities. With regard to the former, under traditional rate-of-return regulation, state regulators determine whether utilities' costs are reasonable and legitimate before allowing them to be passed on to consumers. Utilities in general are allowed to earn revenues equal to the sum of accrued operation expenses, the actual cost of servicing debt and preferred stock, and a normal profit, computed as the product of a "fair" rate of return times the book value of common equity (referred to as *rate-base*) (Khurana and Loudder 1994). With regard to approvals for new generation and transmission facilities, states historically regulated electric utilities through a "regulatory compact," whereby they grant utilities service territories in which the utilities have the exclusive right to serve retail customers. In exchange, the utilities are obligated to serve all consumers on demand in that territory. This service obligation therefore requires electric utilities to maintain sufficient capacity for generation, transmission, and distribution of power to serve all present and future customers.

Appendix B

Response to Deregulation

A. *Example of Responses to Deregulation as Stated in Form 10-K, Idaho Power (March 14, 1996)*

Item 1 (Business). Increasing competitiveness in the electric power marketplace, the potential ability of retail customers to choose their electric provider and the potential for deregulation of the electric power industry, all indicate a need for the Company to adjust its resource acquisition policy toward a greater emphasis on resource marketability. In order to avoid burdening the Company and its customers with unnecessary future power supply costs and higher rates, the Company has adopted a policy of acquiring all new resources as close as possible to the actual time of need and selecting the lowest cost resources meeting all of the Company's requirements. In practice, this policy will result in the purchase of power from others through the marketplace whenever purchases are the lowest cost resources, and new investment in resource ownership by the Company only when a Company-owned resource would be cost effective in the market.

Item 7 (MD&A). To remain successful, Idaho Power must continue to provide value to its shareholders in the face of this new competitive environment. The Company's vision involves three strategies for creating this value:

selective and efficient use of capital; an enhanced customer orientation; and innovative, efficient operations. Because future prices for power will be determined more by market forces and less by regulatory administration, the Company must be very selective and efficient in the use and allocation of capital. Idaho Power will invest in improving and expanding its core business, in developing new opportunities beyond its current service territory, and in continuing to develop non-regulated opportunities consistent with the Company's core competencies.

Based on this vision and the Company's efforts to increase shareholder and customer value, Idaho Power is transforming its operations to improve both efficiency and customer service. Teams of employees are redesigning work processes. In some cases, these improved processes are successfully in place. During 1995, Idaho Power announced plans for voluntary and involuntary separation packages in the event of workforce reductions resulting from its reorganization efforts.

B. *Summary of Assessments of and Responses to Deregulation as Stated in the 1995 10-Ks of 99 Electric Utility Firms*

Assets-in-place.

Efforts to lower operating costs and to improve efficiencies and synergies.

Reduction of workforce.

Reduction of capital budget and more careful management of capital spending.

Consolidation of divisions to eliminate duplicated functions.

Change in criteria for capital budget decisions to marketability of the capacity in a competitive market.

Minimization of price increases.

Investment Opportunities.

Development of new and better, high-value services and products.

Quicker reaction to business complexities and opportunities.

Increase of purchased power to reduce the uncertainty of owning new plants.

Increase in reorganizations, mergers and acquisitions, and joint ventures to increase the scale and diversity of operations (named as critical factors for success).

Active participation in the competitive opportunities proceedings (in state legislatures) in the states in which it operates.

Pursuit and development of new opportunities in unregulated markets to strengthen the longterm competitiveness and profitability.

Creation of new investment opportunities.

Creation of additional demand for electricity by encouraging the development of electric motor vehicles.

Acquisition of additional low-cost resources.

Assistance of customers in acquiring and implementing energy efficiency measures.

Investment in nonregulated projects, including domestic and international power production.

Pursuit of domestic and international diversified business opportunities that are synergistic with the company's core business.

Other.

Increase in business risks with resulting pressures on utility credit quality and investor returns.

Creation of stranded plant investments and stranded costs for supply contracts.

Appendix C

Examples of Year 1995 Proxy Disclosures on Changes in CEO Compensation Structure as a Result of Deregulation

A. General Public Utilities Corporation

The executive compensation program at GPU was revised to increase the portion of pay that is based on business results . . .

> Mr. Leva's [the CEO's] award was based on objectives of return on equity (40%), nuclear safety (20%), efforts to position the Corporation for the changing industry (20%) and future positioning of the Corporation with regard to the cost of energy supply (20%).
>
> GPU also took a leadership position in supporting legislative and regulatory changes considered essential if the Corporation is to compete effectively in the future. A new Corporate Development function was established to investigate and pursue new business opportunities.
>
> Mr. Leva continued to provide both leadership and a personal example of support for the cultural change efforts at GPU. These culture change efforts include initiatives to educate employees on the need to increase their focus on business results. Among these initiatives is a newly implemented program of expanded incentive pay opportunities whereby most of the GPU workforce now have a portion of pay linked to achievement of business results.

B. Idaho Power

> The incentive awards are based upon pre-established performance goals designed to promote safety, control capital expenditures, control operation and maintenance expenses and increase annual earnings per share. Each goal is designed with a minimum, target and maximum performance payout level and is weighted evenly at 25 percent for each of the four goals.

C. Ohio Edison

> The Committee approved five 1995 corporate financial and strategic objectives for Mr. Holland. These objectives related to the achievement of

confidential target levels regarding earnings per share, operational cash flow, cost reductions and revenue enhancements identified by the Company's Performance Initiative Programs, customer service satisfaction and generating plant capacity. These objectives provided 40%, 20%, 20%, 10% and 10%, respectively, of Mr. Holland's target annual incentive opportunity.

D. PSCompany of Colorado

Each executive earns the right to receive an award if pre-established corporate goals (based on earnings per share) are met. In addition, the Committee may adjust these awards based on its subjective assessment of business unit and individual performance. This assessment focuses on factors such as customer service, actual resource allocations relative to budget, other strategic business unit factors, and individual performance; however, formal weightings are not assigned to these factors.

Appendix D

Performance Measures Used in Annual Bonus Contracts as Stated in 1995 and 2001 Proxies

Performance Measure	1995 (n = 92)	2001 (n = 58)
A. Percentage of Firms Citing the Performance Measure as a Basis for the Annual Bonus		
Earnings per share	58.6%	53.5%
Operation and maintenance expenses	41.4%	4.7%
Customer satisfaction	30.3%	11.6%
Return on equity	21.2%	25.8%
Stock returns	15.2%	2.3%
Cost (to the Customer) per Kwh	13.1%	0.0%
Safety and reliability	13.1%	11.6%
Cash flow	9.1%	12.1%
Productivity	9.1%	.00%
Dividends	7.1%	2.3%
Firms providing no specific performance measures	13.1%	5.2%
Firms providing bonus formula details	26.3%	15.5%
B. Mean Weights on Performance Measures for Firms Providing Bonus Formula Details		
Earnings per share	51.9%	63.0%
Operation and maintenance expenses	24.3%	25.0%
Customer satisfaction	21.2%	10.0%
Return on equity	49.7%	32.0%
Stock returns	26.1%	N/A*
Cost (to the Customer) per Kwh	31.3%	N/A*
Safety and reliability	21.7%	10.0%
Cash flow	22.5%	22.5.%

* No firms disclosed the exacts weights used on this factor for 2001.

Appendix E

Items Sampled from Federal Energy Regulatory Commission Form 1

Form-1 Page No.	Line No.	Data Item	Main Heading	Description of data items
114	2	oprev	Utility operating income	Operating revenue
114	4	opexp	Utility operating income	Operation expenses
114	5	maint	Utility operating income	Maintenance expenses
300	2	rsale	Sales of electricity	Residential sales ($)
300	2	rsold	Sales of electricity	Megawatt hours sold
300	2	rcust	Sales of electricity	Average number of customers/month
300	4	csale	Sales of electricity	Small or commercial sales ($)
300	4	csold	Sales of electricity	Megawatt hours sold
300	4	ccust	Sales of electricity	Average number of customers/month
300	5	isale	Sales of electricity	Large or industrial sales ($)
300	5	isold	Sales of electricity	Megawatt hours sold
300	5	icust	Sales of electricity	Average number of customers/month
300	10	tsale	Sales of electricity	Total sales to ultimate consumers ($)
300	10	tsold	Sales of electricity	Megawatt hours sold
300	10	tcust	Sales of electricity	Average number of customers/month
320	13	steamop	1. Power production expenses—A. Steam power generation	Total operation (sum of operation supervision and engineering, fuel, steam expenses, steam from other sources less steam transferred, electric expenses, miscellaneous steam power expenses, rents, allowances)
320	21	steamp	1. Power production expenses—A. Steam power generation	Total power production expenses: steam power (sum of "steamop" and maintenance supervision and engineering, maintence of structures, maintenance of boiler plant, maintenance of electric plant, maintenance of miscellaneous steam plant)
320	33	nukerp	1. Power production expenses—B. Nuclear power generation	Total operation (sum of operation supervision and engineering, fuel, coolants and water, steam expenses, steam from other sources less steam transferred, electric expenses, miscellaneous nuclear power expenses, rents)

320	41	nukerp	1. Power production expenses— B. Nuclear power generation	Total power production expenses: nuclear power (sum of nukerop and maintenance supervision and engineering, maintence of structures, maintenance of reactor plant equipment, maintenance of electric plant, maintenance of miscellaneous nuclear plant)
320	50	hydroop	1. Power production expenses— C. Hydraulic power generation	Total operation (sum of operation supervision and engineering, water for power, hydraulic expenses, electric expenses, miscellaneous hydraulic power generation expenses, rents)
320	59	hydrop	1. Power production expenses— C. Hydraulic power generation	Total power production expenses: hydraulic power (sum of "hydroop" and maintenance supervision and engineering, maintenance of structures, maintenance of reservoirs, dams, and waterways, maintenance of electric plant, maintenance of miscellaneous hydraulic plant)
320	67	otherop	1. Power production expenses— D. Other power generation	Total operation (sum of operation supervision and engineering; fuel; generation expenses; miscellaneous other power generation expenses; rents)
320	74	otherp	1. Power production expenses— D. other power generation	Total power production expenses: other power (sum of otherop and maintenance supervsion and engineering, maintenance of structures, maintenance of generating and electric plant, maintenance of miscellanous other power generation)
320	76	purchp	1. Power production expenses— E. Other power supply expenses	Purchased power
320	80	pronm	1. Power production expenses— E. Other power supply expenses	Total power production expenses (sum of steamp, nukerp, hydrop, otherp, purchp)

Appendix E (*Continued*)

Form-1 Page No.	Line No.	Data Item	Main Heading	Description of data items
320	100	tronm	2. Transmission expenses	Total transmission expenses (sum of transmission operation supervision and engineering, load dispatching, station expenses, overhead lines expenses, underground lines expenses, transmission of electricity by others, miscellaneous transmission expenses, rents, transmission maintenance supervision and engineering, maintenance of structures, maintenance of station equipment, maintenance of overhead lines, maintenance of underground lines, maintenance of miscellaneous transmission plant)
320	126	dsonm	3. Distribution expenses	Total distribution expenses (sum of distribution operation supervision and engineering, load dispatching, station expenses, overhead line expenses, underground line expenses, street lighting and signal system expenses, meter expenses, customer installations expenses, miscellaneous expenses, rents, maintenance supervision and engineering, maintenane of structures, maintenance of station equipment, maintenanance of overhead lines, maintentance of underground lines, maintenace of line transformers, maintenance of street lighting and signal systems, maintenance of meters, maintenance of miscellaneous distribution plant)
320	134	caonm	4. Customer accounts expenses	Total customer accounts expenses (sum of supervision, meter reading expenses, customer records and collection expenses, uncollectible accounts, miscellaneous customer accounts expenses)
320	141	csonm	5. Customer service and informational expenses	total customer service and information expenses (sum of supervision, customer assistance expenses, informational and instructional expenses, miscellaneous customer service and informational expenses)

320	148	rvonm	6. Sales expenses	Total sales expenses (sum of supervision, demonstrating and selling expenses, advertising expenses, miscellaneous sales expenses)
320	168	amonm	7. Administrative and general expenses	Total administrative and general expenses (sum of administrative and general salaries, office supples and expenses less administrative expense transferred, outside services employed, property insurance, injuries and damages, employee pensions and benefits, franchise requirements, regulatory commission expenses less duplicate charges, general advertising expenses, miscellaneous general expenses, rents, maintenance of general plant)
320	302	full	Number of electric department employees	Total regular full-time employees
320	303	part	Number of electric department employees	Total part-time and temporary employees
320	304	all	Number of electric department Employees	Total employees
354	18	prsal	Distribution of salaries and wages	Total salaries for production
354	19	trsal	Distribution of salaries and wages	Total salaries for transmission
354	20	dssal	Distribution of salaries and wages	Total salaries for distribution
354	21	casal	Distribution of salaries and wages	Total salaries for customer accounts
354	22	cssal	Distribution of salaries and wages	Total salaries for customer service and informational
354	23	rvsal	Distribution of salaries and wages	Total salaries for sales
354	24	amsal	Distribution of salaries and wages	Total salaries for administrative and general
354	25	labor	Distribution of salaries and wages	Total salaries (sum of lines 18 through 24)
401	3	steam	Electric energy account—Sources of energy (megawatt hours)	Steam (megawatt hours)

Appendix E (*Continued*)

Form-1 Page No.	Line No.	Data Item	Main Heading	Description of data items
401	4	nuker	Electric energy account—Sources of energy (megawatt hours)	Nuclear (megawatt hours)
401	5	hydrc	Electric energy account—Sources of energy (megawatt hours)	Hydro-conventional (megawatt hours)
401	7	hydrp	Electric energy account—Sources of energy (megawatt hours)	Hydro-pumped storage (megawatt hours)
401	9	gener	Electric energy account—Sources of energy (megawatt hours)	Net generation (megawatt hours; sum of lines 3 through 8)
401	10	purch	Electric energy account—Sources of energy (megawatt hours)	Purchases (megawatt hours)
1	14	exchn	Electric energy account—Sources of energy (megawatt hours)	Net exchanges (power received less power delivered; megawatt hours)
401	18	other	Electric energy account—Sources of energy (megawatt hours)	Net transmission for other (power received less power delivered; megawatt hours)
401	20	total	Electric energy account—Sources of energy (megawatt hours)	Total (sum of gener, purchp, exchn, other)
401	22	custm	Electric energy account—Disposition of energy	Sales to ultimate consumers (including interdepartmental sales; megawatt hours)
401	23	requr	Electric energy account—Disposition of energy	Requirement sales for resale (megawatt hours)
401	24	nonre	Electric energy account—Disposition of energy	Non-requirement sales for resale (megawatt hours)

Appendix F

Duke Energy's "Compensation Philosophy" (Year 2000, Proxy Statement): Compensation of the Chief Executive Officer

> The Compensation Committee reviews annually the compensation of the Chief Executive Officer and recommends any adjustments to the Board of Directors for approval. In 2000, the Compensation Committee retained the consulting firm of Frederick W. Cook and Co. to conduct a review of the compensation of the Chief Executive Officer. The Chief Executive Officer participates in the same programs and receives compensation based upon the same criteria as Duke Energy's other executive officers. However, the Chief Executive Officer's compensation reflects the greater policy- and decision-making authority that the Chief Executive Officer holds and the higher level of responsibility he has with respect to the strategic direction of Duke Energy and its financial and operating results.
>
> The components of Mr. Priory's 2000 compensation were:

Base Salary: After considering Duke Energy's overall performance and competitive practices, the Compensation Committee recommended, and the Board of Directors approved, a 5.6% increase in Mr. Priory's base salary, to $950,000, effective March 1, 2000. In October 2000, the Compensation Committee recommended, and the Board of Directors approved, an additional adjustment to Mr. Priory's base salary, increasing it to $962,500, retroactive to March 1, 2000. This additional base salary increase compensated Mr. Priory for the discontinuation of certain tax gross-ups on executive pension and savings benefits.

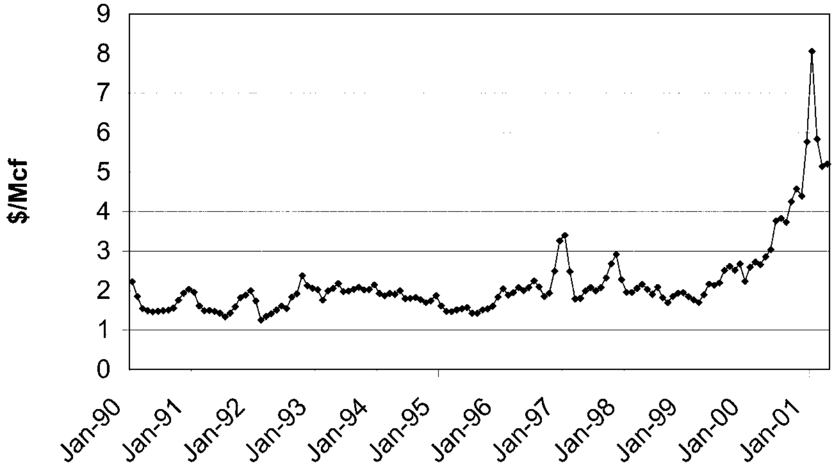
Annual Incentives: Annual incentive compensation for Mr. Priory is based solely upon EPS results. Based on 2000 EPS performance, Mr. Priory received a payment of $1,908,328, representing 200% of his target incentive opportunity.

Long-Term Incentives: In February 2000, Mr. Priory received a stock option award for 400,000 shares of Duke Energy Common Stock with an exercise price at fair market value on the date of grant. The stock option has a 10-year term and will vest 25% on each of the first four anniversaries of the grant date.

> It is the Compensation Committee's intention that, when taken together, the components of Mr. Priory's pay, including base salary, annual incentives, short-term incentive opportunity and long-term incentives, will result in compensation which approximates the 50th percentile of the market when incentive plan performance expectations are met and in compensation as high as the 75th percentile of the market when incentive plan performance expectations are exceeded.

Appendix G

Natural Gas Wellhead Prices in $/Mcf (Source: Energy Information Agency)



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