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Rate regulation and earnings management: evidence from the U.S. electric utility industry

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RATE REGULATION AND EARNINGS MANAGEMENT: EVIDENCE FROM THE U.S. ELECTRIC UTILITY INDUSTRY

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TABLE OF CONTENTS

LIST OF TABLES

ABSTRACT

Although accounting research continues to focus on earnings management, few studies have done so within the context of a single industry, and only one study to date (Paek 2001) has investigated this phenomenon within the context of U.S. rate-regulated electric utilities. Most utilities are viewed as natural monopolies, and therefore are subjected to rate regulation. These firms are permitted to earn a prescribed rate of return on an approved rate base. Although utilities are subjected to greater scrutiny than non-regulated public companies, regulatory restraint may create incentives to manage earnings (Healy and Whalen 1999), especially coincident with a utility's request to regulators for a rate increase. I use samples drawn from the electric utility and manufacturing industries to examine the following three research questions. First, does earnings management in rate-regulated electric utilities, as represented by the magnitude of discretionary accruals, significantly differ from that observed in comparable non-regulated companies? The second question probes whether the deregulation of the generation and marketing of electricity within the electric utility industry that began in the late 1990s, significantly altered the opportunity to observe earnings management. The third question focuses on whether rate-regulated electric utilities manage earnings downward in the year that they file for a rate increase? And, if indications of earnings management are observed, is industry-specific GAAP used to decrease earnings? I estimate the earnings management metric, discretionary accruals, using accrual expectation models from prior research. Results indicate the magnitude of discretionary accruals, on average, is significantly smaller for rate-regulated electric utilities than for non-regulated companies suggesting that rate regulation is adequate in constraining earnings management. This is corroborated by the finding that earnings management metric increased for those utilities affected by deregulation. Finally, in an intra-industry comparison, I observe

significantly lower discretionary accruals for utilities in the year they request rate increases when compared to years in which rate increases are not requested. This result is consistent with opportunistic earnings management and raises a social welfare issue. Evidence that industry-specific GAAP is used to manage earnings downward is inconclusive.

1. INTRODUCTION

Earnings management is defined by Healey and Whalen (1999) as the use of managerial judgment "in (the) financial reporting process and in structuring transactions to alter financial reports to either mislead some stakeholders about the underlying economic performance of the company, or to influence contractual outcomes that depend on reported accounting numbers"(p. 368). It constitutes one of the most popular topics in current accounting research. However, despite the considerable attention earnings management is given by accounting researchers, most academic studies have excluded rate-regulated firms, such as electric utilities[1]. Only one study to date has examined earnings management within the U.S. electric utility industry, and it narrowly focuses on comparing pre-1994 utilities based on regulatory differences.[2]

Historically, electric utilities enjoy a unique status because of their classification as natural monopolies (Blacconiere et al. 2000). The potential for monopolistic abuse begets regulatory oversight; in order to protect "captive" consumers[3], the electric utility industry is highly regulated by state and federal agencies (Loudder et al. 1996).[4] Whereas all industries in the U.S. are regulated to some degree,[5] rate regulation imposes regulatory oversight that is explicitly tied to accounting information. Healy and Whalen (1999) note that, "it is frequently asserted that such regulations create incentives to manage the income statement and balance sheet variables of interest to regulators" (p. 377). However, because of rate regulation, accounting issues affecting electric utilities tend to be treated by researchers as special cases and,

[1] An exception is a study of earnings management within the Spanish electric utility industry (Gill-de-Albornoz and Illueca 2005).
[2] Paek (2001) uses a sample of U.S. electric utilities that he then classifies as rate-regulated and incentive-regulated based on Landon (1993). Paek finds that utilities adopting incentive regulation have smaller discretionary accruals than rate-regulated counterparts.
[3] "Captive" customers are those who have no alternative to purchase electricity from another firm.
[4] The Energy Policy Act of 1992 was enacted in an effort to deregulate and reduce wholesale electricity prices, and to provide the impetus for state-based retail deregulation of electricity generation and marketing.
[5] For purposes of exposition, firms not subject to rate regulation are referred to as "non-regulated" firms.

as such, are differentiated from non-regulated companies. Hence, accounting researchers employing cross-sectional inter-industry research designs usually exclude rate-regulated firms from their samples to strengthen internal validity. Conversely, single-industry research designs focusing on rate-regulated industries encounter limitations regarding external validity.

Both internal and external validity concerns may arise when including rate-regulated sample firms if there is significant variation in how rate regulation is applied across regulatory jurisdictions. For example, focusing on electric utilities, consider the following two simplified regulatory regimes; "strict" rate regulation and incentive regulation. Under the more rigid form of rate regulation, electric utilities are narrowly permitted to apply cost-plus pricing (Nwaeze 2000). That is, utilities are allowed to set rates that recover their operating costs, plus earn an authorized (normal) profit. Alternatively, under an incentive form of rate regulation, electric utilities are permitted to share with consumers (through reduced rates) a portion of any profits earned above the allowed rate of return. The latter regime provides an economic incentive for utilities to reduce costs, whereas the former does not.

Federal and state statutes require regulated U.S. electric utilities to submit requests for rate increases to state Public Utility Commissions (PUCs). PUCs then evaluate these rate requests and conduct public hearings open to all affected parties before rendering their decisions. However, even under such scrutiny, opportunities may exist for utilities to employ strategic reporting to circumvent this regulatory oversight. Sappington (1980) and Sherman (1989), for example, argue that utilities may deliberately understate earnings before rate reviews to circumvent regulatory constraints. Sappington (1980) further argues that this regulatory circumvention is potentially made possible because regulators may not be familiar with regulatory accounting issues particular to utilities. To the extent that public utility commissions lack the capability to uncover biased financial reporting, earnings management may continue unabated. This leads to the conjecture that utilities requesting rate increases, and in which regulatory approval depends on accounting data, have incentives to report depressed earnings levels in order to maximize the probability of successfully gaining such approval.[6] One method of decreasing earnings is reducing the level of discretionary accruals as permitted under Generally Accepted Accounting Principles (GAAP).

In providing guidance for accrual accounting, GAAP does not constrain rate-regulated electric utilities to the extent that it limits non-regulated companies. Statement of Financial Accounting Standards 71 (SFAS 71), *Accounting for the Effects of Certain Types of Regulation,* specifically allows qualifying[7] rate-regulated utilities greater latitude in making accruals/deferrals than non-regulated companies (FASB 1982). SFAS 71 allows a rate-regulated utility to capitalize and amortize a cost that would ordinarily be charged to income by other businesses. For example, the costs of repairing storm damage (e.g., Hurricane Katrina) might be deferred and recovered over an extended period. Likewise, a regulated utility may include in current rates sufficient revenue intended to cover costs that are expected to be incurred in the future (e.g., nuclear fuel storage and estimated nuclear plant decommissioning costs), with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts (FASB 1982). "Regulatory" assets and liabilities are recorded on the balance sheet to accommodate deferred costs and revenues earned in advance respectively. Regulatory assets are considered necessary by regulators because they tend to act as "shock absorbers," without which,

[6]In contrast to depressing earnings prior to requests for rate increases, the political cost hypothesis suggests that managers artificially reduce reported earnings after the government establishes rate (tariff) increases in order to reduce political costs and public visibility (Gill-de-Albornoz and Illueca 2005).
[7]According to FASB, a "qualifying entity" may apply SFAS 71 if it has operations that meet all of the following criteria; i) rates charged to customers are established or approved by a regulator or governing board empowered by statute, ii) rates are designed to recoup specific costs of providing the service and, iii) based on demand and competition, rates can be charged and collected.

electricity rates would fluctuate significantly, to the detriment of "captured" utility consumers. Therefore GAAP provides more (less) discretion to rate-regulated (non-regulated) companies to defer or accrue costs and to accelerate revenues. Management's discretionary choices include: when, what, and how much to defer or accrue, periods for recovery of deferred items, depreciation or amortization methods for expensing capitalized costs, and reporting assumptions (D'Souza et al. 1999).

Given the increased discretion granted utility managers to defer costs, the study's empirical tests focus on discretionary accrual as the earnings management metric. Discretionary accruals are estimated using the Jones (1991) model in addition to several modified versions. Despite its criticism, the Jones model is widely applied in earnings management studies.[8]

Using discretionary accrual models found in the literature, this study investigates three research questions. First, does the magnitude of earnings management in rate-regulated electric utilities, as represented by discretionary accruals, significantly differ from that observed in comparable non-regulated companies? Discretionary accruals for a sample of rate-regulated electric utilities are compared with those of a control sample of comparable non-regulated manufacturing companies. This descriptive comparison requires using a time series research design to estimate firm-specific discretionary accruals for utilities and manufacturing companies, the group means of which are then statistically compared. Because this research question is not conditioned on any specific management action, both signed accruals and their absolute values are compared in this test. Subsequently, a cross-sectional design is used to determine the statistical significance of the difference in the inter-industry means of discretionary accruals for each year, as well as for the pooled sample period.

[8] The time series model used by Jones (1991) assumes temporal stability in the earnings-generating process; long time series research designs may violate this assumption. Conversely, cross-sectional models assume all firms use the same earnings-generating process, and any significant firm-specific differences may violate this assumption.

Results indicate that, on average, signed discretionary accruals of rate-regulated electric utilities are not significantly different from zero, whereas the means of the signed discretionary accruals for manufacturing firms are significantly negative. Furthermore, the absolute values of discretionary accruals of electric utilities are significantly smaller than those observed for a matched sample of non-regulated manufacturing companies. These time series results lead to the conclusion that, on average, electric utilities do not manage earnings while non-regulated firms do. This finding is consistent with the proposition that regulatory scrutiny, on average, reduces earnings management opportunities. Cross-sectional tests confirm that the magnitudes of discretionary accruals, as well as total accruals, of the electric utility sample are significantly smaller than those estimated for matched manufacturing firms. These findings provide empirical justification for accounting researchers to exclude rate-regulated firms from cross-sectional, inter-industry research designs that use the discretionary accrual metric to investigate earnings management; not to do so would weaken internal validity and the power of the test.

The second question examines whether deregulatory forces that affected some regulatory jurisdictions in the late 1990s increased the opportunities for earnings management. Specifically, as a result of the Energy Policy Act of 1992, which effectively deregulated the wholesale pricing of electricity by 1996, certain state regulators and legislatures began thereafter to deregulate the retail generation and marketing of electricity (i.e., providing a choice of suppliers to the end-user) within their jurisdictions. I investigate this question by using 1999 as a temporal benchmark to split the pooled utility sample, and then compare discretionary accrual metrics in the pre- and post-1999 periods. Because deregulation is associated with reduced regulatory scrutiny and increased economic incentives, I would expect the magnitudes of discretionary accruals of utilities affected by deregulation to increase. Results indicate that this, in fact, occurred, and there is some evidence that this increase was associated with deregulation rather than other macroeconomic forces.

The third research question focuses on whether rate-regulated electric utilities manage earnings downward in the year in which they file for rate increases. In addressing this question I draw an additional sample of those electric utilities that requested a rate increase in at least one year of the 1994-2005 sample period. In the years, in which sample firms did not request a rate increase, they are used as a control group for comparative purposes. Findings using a cross-sectional research design indicate that the indicator variable for those utilities requesting rate increases is significantly negative, consistent with managers depressing earnings in the year the rate increase is requested. I find earnings management continuing to the year after the submission of a rate increase request. These results infer that, even if there is no evidence of earnings management, on average, as found in testing Hypothesis 1, there is evidence of downward earnings management when conditioned on the rate request process. If regulators heavily rely on this earnings information in their regulatory decisions to increase rates, this finding should be of interest, as it potentially biases their decision-making process and could lead to a wealth transfer between shareholders and captive utility customers.

An associated question arises if earnings management by utilities is detected using the discretionary accrual metric. Which financial accounts were used to effect earnings management? In particular, were regulatory assets, deferred costs specifically permitted under GAAP for rate-regulated firms (SFAS 71) used to manage earnings? I therefore explore whether modifying the Jones (1991) model, by isolating regulatory assets as an additional independent variable, can improve the model's ability to estimate discretionary accruals. To address this question, I hand-collect regulatory assets data from SEC 10-K filings and re-estimate accrual expectation models with regulatory assets as an additional independent variable. Results indicate that the regulatory assets variable is not significant in the accrual models. This result suggests that regulatory assets account is not used by utilities to manage earnings. This finding provides additional evidence of the adequacy of regulatory scrutiny. Because the establishment of regulatory assets requires regulatory approval, this finding suggests the regulatory process precludes managerial manipulation of regulatory assets. The implication of this finding also is that the original Jones (1991) model and its modified versions work as well for rate-regulated electric utilities as they do for non-regulated companies. However, the deferred tax component in regulatory assets may be noisy. Decomposing regulatory assets into components with a view to excluding deferred tax account and re-examining the research question is left for future research.

I perform a variety of robustness tests for the: independence of the samples; possibility of a structural change due to deregulation; exclusion of firms with competing capital market incentives for earnings management; reversal of accruals, and; other alternate explanations. After these robustness and sensitivity tests, the study's primary results and the associated conclusions remain unchanged.

This study represents the first comprehensive attempt to examine earnings management within the rate-regulated U.S. electric utility industry. Electric utilities are excluded from earnings management studies using cross-sectional inter-industry research designs because of their operating environment and accounting differences. Although Paek (2001) found differences in his pre-1994 sample's discretionary accruals in which utilities were grouped as either "rate-regulated" or "incentive regulated,"[9] his findings of any relative differences between these groups have limited application. Therefore the current study represents an initial broad-based

[9]As determined by another study (Landon, 1993).

examination of earnings management within this industry and provides empirical evidence regarding the adequacy of regulatory scrutiny. This represents the study's primary contribution.

This study additionally makes a contribution from the public policy perspective. The currently stalled attempt to deregulate the retail generation and marketing of electricity within the U.S. may have spawned unintended consequences of increased earnings management opportunities. Policymakers should be aware of such consequences in the context of the larger ongoing debate over the restructuring of the electric utility industry. Finally, the study finds evidence of earnings management by rate-regulated utilities during periods in which rate requests are under consideration. This raises regulatory and social welfare issues. First, since management can depress earnings in order to bolster their requests for increasing rates, regulators should be fully aware of the potential for receiving biased earnings information. This might lead to increased regulatory (monitoring) costs. Second, traditional earnings management is frequently motivated by economic incentives for managers to benefit at the expense of shareholders. In the rate-regulated setting, operating costs are "passed through" to ratepayers. Increasing costs in order to decrease earnings increases the amount passed through which must be covered in rates. However, this increase is only a second order effect; the primary effect being that if regulators are persuaded to increase the price of electricity by increasing the allowed rate of return. Unlike non-regulated earnings management studies, this raises the social welfare issue of a wealth transfer between ratepayers (captive customers) and shareholders. Providing empirical evidence of earnings management within this context provides a unique contribution to the literature.

In the following section, I review prior literature and develop testable hypotheses. Section three describes sample selections and discusses the earnings management models and research designs used to test the hypotheses. Section four provides empirical results. I describe and report results of robustness tests in section five and the final section presents a summary and conclusions.

2. LITERATURE REVIEW AND HYPOTHESES DEVELOPMENT

2.1 Overview of the Electric Utility Industry

The electric utility industry represents one of the largest industries in the United States with total annual assets and revenues exceeding $700 billion and $298 billion respectively, and employing more than 400,000 personnel (EEI 2006). Electricity is the life blood of the US economy and all industrial economies. The electric utility industry supplies an essential service that is indispensable to industrial, commercial, and residential customers. The number of customers by category in 2005 were; industrial 733,862, transportation 518, commercial 16,871,940; and residential 120,760,389; (EIA 2006, and EEI 2006).

The majority of customers served by electric companies are residential users, but industrial customers consume more than one-third of electricity sold. These statistics demonstrate the strategic importance of electric utility industry. Inadequate and unreliable supplies of electricity cause not only inconvenience, but also economic loss due to reduced economic output. In the extreme weather conditions, fatalities may result from electrical outages (e.g., power disruptions to hospitals during Hurricane Katrina and deaths of the elderly during heat waves). Industrial users strive to ensure an affordable, safe and uninterrupted supply of electricity. The industry's generating capacity supports economic growth and productivity, promotes business development, and provides increasing employment opportunities to hundreds of thousands.

In 2005, the latest year for which data are available, US production of electricity was 2,554,050 million kilowatt hours. The major sources of energy used to generate electricity include: coal 49.7%; nuclear 19.3%; natural gas[10] 18.7%; hydro 6.5%; oil/petroleum 3%; and

[10] In 2005, the supply of natural gas faced unprecedented disruptions from hurricanes Katrina and Rita that devastated the U.S. Gulf coast.

other 2.8% (EIA 2006; EEI 2006). Coal is the largest fuel source used for generating electricity in the U.S., followed by nuclear and natural gas in that order. When viewed from the context of the current global-warming debate, fossil fuels, which produce carbon dioxide (the leading greenhouse gas) supply about 70% of electricity-generating requirements. Coal, petroleum, and gas are currently the most dominant fossil fuels[11] used by the industry.

Electric utilities have historically been organized as three major vertically integrated business units: generation plants that produce electricity; transmission facilities that deliver electricity from generation plants to substations via high-voltage lines, and; distribution facilities that deliver power from substations to end-use customers (Hyman 1997). The ownership structure of electric utilities in the United States includes investor-owned, government-owned, and cooperatively owned electric utilities.

Historically, investor-owned electric utilities have dominated the industry in electricity generated and sold, and have attracted prior academic studies (e.g Nunez 2007, Bhojraj et al. 2004, and Paek 2001). Investor-owned electric utilities are businesses that are highly regulated and are financed by the sale of stock, bonds, and other financial instruments in the financial markets. In 2005, there were about 236[12] investor-owned utilities representing approximately 75% of U.S. generation, sales and revenues (EIA 2006). Like all businesses, investor-owned electric utilities must earn an acceptable return on investment. Investor-owned electric utilities have two conflicting motives; first, to supply electricity at "reasonable and just" rates and secondly to ensure that investors get adequate return as compensation for the risk capital they

[11] Burning of fossil fuels emits polluting gases into the atmosphere. In 2005, power plant emissions were: sulfur dioxide 10,340 thousand metric tons; nitrogen oxides 3,961 thousand metric tons; and carbon dioxide 2,513,609 thousand metric tons. Whereas pollution control equipment is used to reduce sulfur dioxide and nitrogen oxide emissions, technology has yet to accommodate the sequestration of carbon dioxide in an economically feasible manner.

[12] 181 investor-owned utilities are members of Edison Electric Institute (EEI 2006).

supply. Most investor-owned electric utilities include vertically integrated operating companies that provide basic services for the generation, transmission, and the distribution of electricity.[13] Investor-owned electric utilities operate in all states except Nebraska, where electric utilities consist primarily of municipal and public power districts (EIA 2006).

Government-owned electric utilities are nonprofit local government agencies including municipal utilities that provide service to their communities and nearby consumers at cost, returning surplus funds to consumers in the form of community contributions and reduced rates. As of 2005, there were 2,009 government-owned electric utilities in the United States supplying approximately 10% of generation and accounting for 15% of retail and 14% of industry revenue (EIA 2006).

Cooperative utilities (Co-Ops) are owned by and provide power to customer-members. These electric utilities usually operate in rural areas with a low concentration of consumers. Frequently, these areas have been viewed as uneconomical areas of operations by investor-owned utilities. In 2005, there were 912 cooperative electric utilities in the U.S. representing 9% of sales and revenue, and approximately 4% of generation and generating capacity (EIA 2006).

Until recently, policymakers believed that electric power would be delivered to customers much more economically if a relatively small number of suppliers, insulated from competition, operated in all the three business segments (generation, transmission and distribution). However, during the 1990s, the electric utility industry underwent structural changes. Over the past decade there has been an increasing trend towards deregulation.

[13] A number of electric utilities have adopted a corporate structure consisting of a parent holding company and subsidiary operating companies.

An electric utility operates as a natural monopoly[14] by charging their customers regulated rates for electrical services within a defined geographic service area. Electric utilities differ from non-regulated competitive firms in three ways. First, utilities must provide any user with electrical services within their defined jurisdiction. This obligation is often referred to as part of the "regulatory compact." Second, electric utilities must expand their capacity, or purchase available power from others, as the demand for electrical services increases. Third, operating under prudent management, utilities must charge a rate that provides a reasonable rate of return to their owners (Goodman 1998).

Electric utilities are jointly regulated by the Federal Energy Regulatory Commission (FERC) and State Public Utility Commissions (PUCs)[15]. Regulatory agencies attempt to ensure that utilities operate efficiently, as if in a competitive environment. In general, PUCs have jurisdiction in their respective states over rates to be charged, types of service which can be offered, allowable costs that may be deferred, etc. PUCs also control the issuance of Certificates of Public Convenience and Necessity (CCN) to allow utilities build the facilities necessary to ensure the reliable supply of electricity service. The federal government through the FERC has jurisdiction over interstate as well as intrastate wholesale transactions.

2.2 Rate Regulation and Ratemaking in Electric Utilities

In the U.S., the electric utility industry is rate regulated[16]. Rate regulation is commonly based on statutes and ordinances from local, state and federal governments and enforced by state PUCs and the FERC. Without rate regulation, the electric utility, acting as a natural monopoly,

[14] Although an electric utility is not strictly speaking a natural monopoly, it is commonly referred to as such in accounting literature.

[15] FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting, and other matters in connection with wholesale of electricity and interstate transmission. However, at retail level and within the jurisdiction of each state, PUC handle regulatory matters.

[16] Rate regulation is sometimes referred to as rate-of–return regulation or cost-plus Regulation.

could exploit consumers by charging unreasonably high electricity rates (Loudder et al. 1996; Hayward and Schmidt 1999). According to Hayward and Schmidt (1999), there are five basic objectives of utility regulation. First, regulation should prevent excessive (monopoly) profits and prevent exploitation of consumers through unreasonably higher prices. Rate regulation is required to preclude natural monopolies from excessive use of market power to disadvantage consumers. Second, regulators must ensure that adequate earnings can be realized so that the public utility sector is capable of development and growth to meet projected consumer demand. Third, regulators must require that service be provided to all customers. Fourth, regulation promotes the development of the industry. Finally, regulation should foster managerial efficiency while ensuring public safety. Safety has been a critical objective in the nuclear power program.

The legal precedents for rate regulation in the U.S. extend back to the late 1880s. Governmental rate regulation can be found in the laws of the colonial period. During the colonial period, the legislature in South Carolina fixed rates that could be charged by taverns, ferries, and bakers. In 1714, the governor of New York authorized the courts to set reasonable prices on all liquors retained in public houses. In seventeenth and eighteenth century Virginia, statutes conferred authority on the courts to set maximum rates for drinks, food, lodging, and horse feed. In this early legislation, the common law established and enforced by courts required only reasonable charges for services (Goodman 1998).

Rate regulation in the U.S. over the years has been significantly guided in principle by precedents established in two U.S. Supreme Court decisions: Bluefield Waterworks Co. v. Public Utilities Commission, 262 U.S. 679 (1923), and; Federal Power Commission v. Hope Natural Gas Co., U.S. 591 (1944). In the Hope case, in particular, the Court pronounced:

> . . . The investor has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on debt and dividends on stock. By that standard the return to equity owners should be commensurate with returns on investments in other enterprises having corresponding risks. That return moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit worthiness and to attract capital (U.S. 591, 603).

There are several implications derivable from the Hope case, including:

- Electric utilities have a right to earn adequate revenues and profits for their investors. At a minimum, the investors should earn a return that is commensurate with the opportunity cost of capital. If this objective is not achieved, the industry will not be able to attract investors willing to provide equity capital.
- For the utility industry to grow and expand capacity in response to increased demand for electricity services, the utility must earn adequate revenues that cover not only its operating costs but also its capital costs.
- The utility should earn adequate revenues that provide it capacity to attract and service debt obligations.
- The utility has to project a sound financial condition for contracting and signaling reasons.

Pronouncements in the Hope case ruling are manifested in the ratemaking process.

The ratemaking process begins with a determination of the required revenues (this is also called the revenue criteria). In a simplified form, the required revenues are given as: $Rev = OC + rCB$: Where OC = Operating Costs[17], including maintenance, depreciation and taxes[18], r = the allowed rate of return and CB = the Capital (or Rate) Base. The rate base is the utility's collective assets that provide the service for which rates are charged and thus represent the base (rate base) on which a return should be earned. The allowed rate of return, r is the percentage figure that is applied to the rate base to establish the return to which investors in the utility company are entitled. The regulator uses the following calculations:

Revenue

Less Operating expenses

Less Taxes

Equals Operating income or income available to provide a return on invested capital

And

Operating income / Rate base = Rate of Return.

The electricity price per unit is then determined as the ratio of the projected revenue to projected volume of electricity units to be sold. By approving rate variables that include; revenues, operating costs, the rate base and the allowed rate of return, regulators effectively approve electricity rates charged to customers. Regulators do not necessarily accept estimates and data provided by the company. In accounting and ratemaking jargon, an "above-the-line" revenue or

[17] Fuel costs are a major component of operating costs. Fuel adjustment clauses have been authorized for use for almost 40 years e.g., City of Norfolk Vs. Virginia Electric Power Co, 197 Va. 505, 90 S.E 2d 140 (1955). Electric utilities may be permitted to recoup fluctuating fuel costs on an on going basis without necessarily conducting a full rate case. Such periodically adjusting rate clauses are permitted to be utilized when regulatory commissions identify a particular expense (almost frequently the cost of fuel) that is more volatile compared to utility's other costs. Fuel adjustment clauses are not designed to allow utilities to earn profits.

[18] Since 1922, rate-regulated electric utilities have been allowed to recover taxes as part of their operating costs (*Galveston Electric Company v. Galveston (258 U.S. 388, 399, 1922))*. Because utilities are allowed to recover the taxes they pay, taxing authorities have historically used them as "tax collectors."

expense is one that is included in the rates, while "below-the-line item affects only the company's equity accounts rather than its operating accounts (Goodman 1998). Revenue and operating expenses are adjusted for abnormal weather conditions and changes in the customer load (Hyman 1997). Determining a "fair" or "reasonable" rate of return is usually a formidable task. Regulators and utilities often do not agree as to what is "fair" or "reasonable" when mandated rates are established. Utilities strive to earn as much as possible for their investors, while regulators attempt to protect consumers from contributing to excessive investor returns.

Accounting choices, such as the provision for depreciation[19] and accounting for income taxes[20], play an integral role in the regulatory process since they influence the measurement of financial information provided to PUCs used in the establishing electricity rates (Bauer 1930). In effect, the choice of accounting methods affects how costs are allocated between utility stockholders and rate payers. Whereas Local, State and Federal agencies all exert some influence over utilities operations, state PUCs are responsible for setting allowed rates of return based upon approved capital bases and for monitoring ratemaking variables (Goodman 1998). All rate requests are supported by accounting information provided to regulators by the electric utility. Electric utilities are permitted to charge rates that enable them to earn sufficient revenues that recover their operating costs and earn an allowed rate of return on an approved capital base (Nwaeze 2000).

When filing for rate adjustments, utilities are required to submit detailed revenue and cost data in order for the PUCs to accurately determine the required revenues needed to cover allowed costs, in arriving at rate decisions. Accrual accounting ultimately influences the rate-

[19] Depreciation methods include: Straight line and accelerated deprecation methods (e.g double declining balance and sum-of years' digits). The depreciation method that is chosen has an influence on reported earnings.
[20] Two accounting methods are used: "flow through" and "normalization". Under the former, tax savings are used to reduce the rates in the year in which the savings are received "flowed through" to consumers. Under the latter, the savings are spread over the life of the property which produced the saving (normalization).

setter's ability to make these decisions, by affecting the timing of revenue and costs. Accrual accounting is based on management's choices, within the constraints of GAAP, that ultimately determine future revenues, future cash flows, and recovery of future costs (Abdel-Khalik 1988).

Traditionally, the electric utility has assumed the role of initiating (requesting) rate reviews whenever earnings are projected to fall short of recovering operating costs. However, there are less frequent situations when the PUC requests a rate review if the utility's rate of return exceeds the commission's authorized rate of return (Nowell and Shogren 1991).

Under the ratemaking process, rate-regulated electric utilities are subjected to "prior approval" regarding regulatory requirements. Under the prior-approval requirement, no rates become effective until the PUC has reached its decision regarding the reasonableness of the company's new filing. Similarly, a utility may not commence deferral and amortization of a cost by establishing a special account and expect to recover the amortized cost in rates unless it has requested the commission's approval to do so in advance (Goodman 1998). In most states, utilities must seek authority each time they want to adjust rates[21]. Before rates are approved, all rate requests are subjected to a public hearing. All stakeholders are allowed to participate in the ratemaking process.

A typical rate case proceeds as follows: A regulated electric utility requesting a rate increase first serves a public notice of intent. It then files a rate case petition with the PUC that includes supporting data (including accounting data). The commission staff then investigate the utility's request for a rate change (discovery period). During the discovery period, the utility is

[21] Utilities file for rate changes each time it is deemed necessary. In order to decrease the frequency of filing formal rate requests, some PUCs use Price-Capping (e.g., Alabama Power SEC Form 10K filling for 2005). Under Price-Cap regulation, the PUC sets a price ceiling or cap and the firm is allowed to charge any price under the cap. Sibley (1989), however, argues that although price-cap avoids a lengthy regulatory hearing, it gives utilities broad latitude in pricing.

required to justify all of its expenses for the operations of the company. An expense that the commission staff determines to be improper or unnecessary is disallowed and excluded from the approved costs the utility is allowed to collect from its customers. The staff also examines the amount utility stockholders have invested in plant and other facilities and calculates a reasonable return on investment necessary to provide quality service. After the completion of the staff's investigation, an administrative hearing, which is open to the public, is held on the merits of the application. At the conclusion of the hearing, the administrative law judge forwards a proposed recommendation to the commissioners for their consideration. Upon this submission, the commissioners review the record that has been developed and issue a decision at the commission's monthly Business and Executive Session. The commissioners' decision determines the level of rates the company will be permitted to collect. Once the final order is issued, the commission's decision can be appealed. During the time between filing of the rate case petition and approval of new rates (regulatory lag), current rates are frozen (Goodman, 1998).

In considering rate cases, commissions do not consider the utility's size. Besley and Bolten (1994) find that a utility's size (which may proxy for political power) does not appear to be a significant impediment for regulators when setting rates. Their study failed to reject the null hypothesis that regulated rates for both large and small utilities are equal over the period of their study.

The preceding discussion suggests that the process of ratemaking in rate-regulated electric utilities provides opportunities for earnings management, especially given the fact that utilities' operating costs are reimbursable. A utility can artificially increase operating costs so as to enhance chances of higher rates being approved. With higher rates, utilities maximize return to their shareholders at the expense of ratepayers. Moreover due to asymmetrical information, the PUC staff may not be able to determine and disallow all irrelevant costs and/or adjust downwards inflated costs (Hagerman 1990).

2.3 Earnings Management and Agency Theory

Earnings management is the opportunistic use of accruals to window-dress and mislead users of financial statements (Dechow and Dichev 2002). Prior accounting research has documented accrual management as the primary method of earnings management (Healey 1985, Jones 1991, McNichols and Wilson 1988, Rangan 1998, Teoh et al. 1998, and Philips et al. 2003).

According to Nelson et al. (2003), common methods of accrual earnings management include, but are not limited to: recognizing too much or too little in approved reserve for the current year; recognizing too much or too little asset impairment; capitalizing and deferring too much or too little expense; deferring too much or too little revenue; modifying methods used for depreciation or amortization, and modifying useful lives, and changing accounting principles. In a recent study, Mvay (2006) finds that companies practice earnings management by shifting expenses between core and special items[22]. Ultimately, earnings management involves opportunistically shifting revenues and expenses between periods in order to achieve strategic reporting objectives. Previous researchers have argued that the level of discretionary accruals reported by companies is a reflection of management's use of "financial reporting discretion" inherent in GAAP to either increase or decrease reported earnings (Defond and Park 2001, Jones 1991, and Schipper 1989). Academic literature has also differentiated between nondiscretionary and discretionary accruals. Nondiscretionary accruals are estimated as expected, or normal, accrual levels for the company considering factors such as their size, industry, and revenue

[22] This type of earnings management is a violation of GAAP.

growth (DeFond and Jiambalvo 1994, Jones 1991, Key 1997, and Kothari et al. 2005). Discretionary accruals are estimated as abnormal accruals, the difference between the actual reported accruals and the expected (non discretionary) accruals, estimated using an accrual expectation model.

Agency theory suggests that an agent acting on behalf of the principal has incentives to act in the agent's self-interest at the expense of the principal (Watts and Zimmerman 1986). From the agency theory perspective, earnings management is motivated by a contractual relationship between an agent and a principal. Agents typically manipulate the accounting system to increase the likelihood of a more favorable performance outcome (Demski et al. 2004). Prior studies have investigated earnings management that is motivated by the following agency relationships; management (agents) vs. owners (principals) in compensation contracts; management (agents) vs. debt providers (principals) in debt contracts and management (agents) vs. investors (principals) in capital markets[23]. These agency relationships have led to three streams of earnings management research in accounting.

The first stream examines earnings management that is motivated by managerial compensation contracts (Healey 1985, Warfield et al. 1995, and Houlthausen et al. 1995). These studies find that managers engage in earnings management if their compensation is linked to accounting numbers. Research findings indicate that if earnings targets for bonuses are binding, managers will use income-increasing discretionary accruals in order to meet compensation criteria. However, once the earnings threshold for the bonus has been met or there is absolutely no chance of meeting the earnings target in the current period, management will take a "big bath", i.e., use income-decreasing accruals in the current period in order to enhance chances of achieving compensation thresholds in the subsequent period. With a bonus program, managers

[23] The relationship between investors and management in the capital market represents an implicit contract.

have incentive to move earnings to a period when a higher bonus can be claimed (Healey 1985). With a stock option program, the incentive is to manipulate accounting earnings in order to influence the stock price and then exercise options to maximize personal income (Liang 2004). Carter et al. (2007) find that financial reporting concerns are positively related to CEO compensation. Studies in this area generally find that managers use discretion over accounting numbers to ensure that their compensation is not at risk.

The second stream of earnings management research relates to that which is motivated by debt covenants. Earnings management may occur if debt covenants are stated in terms of accounting numbers. Studies find that managers, acting on behalf of owners, will use earnings management manipulations to increase earnings in order to avoid the breach or violation of debt covenants (DeFond and Jiambalvo 1994, Sweeney 1994, Begley and Feltham 1999, Dichev and Skinner 2002, and Begley and Freedman 2004). The fundamental assumption implicit in these studies is that the interests of managers are aligned with those of the owners.

A third strand of research investigates earnings management that is motivated by the management's need to attract capital market participants with respect to raising capital. Managers use income-increasing discretionary accruals in order to beat forecast earnings benchmarks (Ayers et al. 2006, Dechow et al. 2003, and Phillips et al. 2003). Dechow and Skinner (2000) document that earnings management will likely be greater when it allows managers to meet the analysts' forecasts. Abarnell and Lehavy (2003) report that firms that have received buy recommendations from analysts are more likely to engage in earnings management in order to meet, or just beat, analysts' forecasts. Teoh et al. (1998), and Rangan (1998) document that firms use discretionary accruals to manage earnings in periods immediately prior to initial public offerings (IPOs) and seasoned equity offerings.

This study extends the earnings management literature by investigating non-traditional agency theory arguments of earnings management that are motivated by regulatory constraints. Earnings management that occurs under rate regulation provides the potential for wealth transfers between ratepayers and utility managers/shareholders, and is a contribution of this study.

2.4 Earnings Management in Regulated Industries

Regulated industries are subjected to regulatory constraints[24] that managers may try to relax using earnings management mechanisms. Schipper (1998) suggests that obtaining favorable treatment from regulators is one of the conditions that give rise to earnings management. Healy and Wahlen (1999) similarly argue that there are incentives for firms in regulated industries to manage earnings in order to stay within regulatory constraints that are stated in terms of accounting numbers. Consistent with this argument, Galai et al. (2003) document that, banks create "hidden reserves" that they use to increase income for the purpose of meeting capital adequacy requirements. Beatty et al. (1995) demonstrate how banks manage their financial reports by altering the timing and magnitude of transactions and accruals decisions in loan charge-offs, loan loss provisions, and the decisions to issue securities to meet regulatory capital levels. Collins et al. (1995) document that profitable banks use loan loss provisions to manage earnings. Beatty and Harris (1999) and Beatty et al. (2002) document that publicly traded banks are more likely than privately held banks to manage earnings upward. Petroni (1992) reports that firms in the regulated property-casualty insurance industry understate claim loss reserves in order to preempt attracting regulatory attention.

According to Heally and Wahlen (1999), other forms of regulation can also provide firms with incentives to manage earnings. Cahan (1992) studied firms that were under investigation

[24] For, instance banks are subjected to regulated capital adequacy requirements.

for anti-trust violations. He finds that discretionary accruals for firms that were under investigation were higher than those for the control sample (not under investigation). He concludes that managers adjust earnings in response to monopoly-related antitrust investigations. Jones (1991) studied firms that were under import relief investigations. She finds that firms use discretionary accruals to manage earnings downward during the period of investigation. Key (1997) studied firms in the cable television industry that were under congressional investigation for breach of industry regulations. She finds that firms manage earnings to diminish profitability when they are under investigation.

Another stream of research identifies and finds evidence that earnings management may be motivated by tax considerations. Guenther (1994) investigates whether accounting earnings are managed in response to the decrease in the statutory corporate tax rate mandated by 1986 Tax Reform Act. He finds that current accruals for large firms are significantly lower in the year prior to the tax rate reduction consistent with managers delaying realized earnings until after the tax rate is reduced. Wang (1994) investigates the effect of book income adjustments on financial reporting. His sample included firms that were subjected to Alternate Minimum Tax (AMT) as enacted in the 1986 Tax Reform Act. He finds that sample firms subjected to AMT exhibit unusual shifts in accounting accruals and suggests that these firms may have managed earnings. Phillips et al. (2003) find the firm's deferred tax expense is a useful metric to detect earnings management.

Findings in this area generally indicate that firms manage earnings in order to minimize taxes. Tax-related motives for managing earnings have minimal implications for ratemaking and are not relevant because taxes are passed through to ratepayers along with operating costs.

2.5 Earnings Management in Rate-Regulated Electric Utilities

With respect to complying with U.S. GAAP, rate-regulated electric utilities are different from other firms, primarily because the Financial Accounting Standard Board (FASB) permits rate-regulated electric utilities to apply SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Given the importance of this accounting standard to accrual decisions permitted by utilities and to this study, I summarize the ratemaking and accounting requirements of SFAS 71 (FASB 1982).

SFAS 71 allows rate-regulated utilities to defer cost recognition to a period other than the period in which the cost would be charged to expense by an unregulated enterprise. This accommodation creates "regulatory assets" (future cash inflows that will result from the ratemaking process), or conversely "regulatory liabilities" (future cash outflows that will result from the ratemaking process). For general-purpose financial reporting, an incurred cost for which a regulator permits recovery in a future period is accounted for like an incurred cost that is reimbursable under a cost-reimbursement-type contract. Accounting requirements that are directly related to the economic effects of rate actions may be imposed on regulated firms by orders of regulatory authorities, and occasionally by court decisions or statutes. This does not necessarily mean that those accounting requirements conform to generally accepted accounting principles (GAAP). For example, a regulatory authority may order an enterprise to capitalize and amortize a cost that would be charged to income currently by an unregulated enterprise. Unless capitalization is appropriate under SFAS 71, GAAP requires the regulated enterprise to charge to income currently.

SFAS 71[25] applies to general-purpose external financial statements of an enterprise that has regulated operations that meet all of the following criteria:

- The enterprise's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.
- The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products.
- In view of the demand for the regulated services or products and the levels of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period of capitalized costs (FASB 1982).

According to SFAS 71, regulatory assets (deferred costs) are created if both of the following criteria are met:

- It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.
- Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs (FASB 1982).

Likewise, regulatory liabilities (revenues earned in advance) are created if the following conditions are met:

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[25] SFAS 71 does not apply to accounting for price controls that are imposed by governmental action in times of emergency, high inflation, or other unusual conditions. Nor does it cover accounting for contracts in general (FASB 1982)

- The regulator may require refunds to customers.
- The regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts.
- A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods (FASB 1982).

SFAS 71 general standard is applied to the following specific standards: allowance for funds used during construction (AFUDC); inter-company profit; accounting for income taxes; and other disclosure.

Regarding AFUDC, in some cases, a regulator permits a utility to capitalize, as part of the cost of plant and equipment, the cost of financing construction, as financed partially by debt and partially by equity. A computed interest cost and a designated cost of equity are capitalized, and net income for the current period is increased by a corresponding amount. After the construction is completed, the resulting capitalized cost is the basis for depreciation and un-recovered investment for ratemaking purposes. In such cases, the amounts capitalized for ratemaking purposes as a cost of acquiring the assets, shall be capitalized for financial reporting purposes.

As pertains to inter-company transactions, profit on sales to regulated affiliates shall not be eliminated in general-purpose financial statements if both of the following criteria are met:

- The sales price is reasonable[26].
- It is probable that, through ratemaking process, future revenue approximately equal to the sales price will result from the regulated affiliate's use of the products.

[26] The sales price is usually considered reasonable if the price is accepted or not challenged by the regulator that governs the regulated affiliate.

In relation to accounting for income taxes, items of revenue and expense are sometimes taxable or deductible in periods other than the periods in which those items are recognized for financial reporting purposes. In some cases, a regulator does not include the income tax effect of certain transactions in allowable costs in period in which the taxes are payable. In such cases, if it is probable that income taxes payable in future years are because of net reversal of timing differences will be recovered through rates based on taxes payable at that time, the enterprise shall record neither the deferred income taxes that result from timing differences nor the related regulatory asset. However, the enterprise shall disclose the cumulative net amount of income tax timing differences for which deferred income taxes have not been provided.

Other disclosure is required in certain cases where a regulator may permit an enterprise to include a cost that would be charged to expense by an unregulated enterprise, to be capitalized and then amortized over a period of time for ratemaking purposes. However, the regulator does not include the unrecovered amount in the utility's rate base. This procedure will not result in a return on investment during the recovery period. If recovery of such major costs is provided without a return on investment during the recovery period, the utility shall disclose the remaining amounts of such assets and the remaining recovery period applicable to them.

Implications of SFAS 71 for earnings management may be substantial. Clearly, this standard gives more discretion to rate-regulated utilities in making accrual decisions. Rate-regulated utilities have more latitude in accruing or deferring costs, earning revenues in advance, and discretionary treatment of transactions between parents and affiliates. Regarding inter-company transactions, Thomas et al. (2004) find that parent companies manage earnings by manipulating transactions with affiliates.

Few studies investigate earnings management in electric utility industry. The only research to-date to investigate earnings management in the U.S. electric utility industry is Paek (2001). A more recent international study was conducted in the Spanish electric utility industry (Gill-de-albornoz and Illueca 2005).

Paek (2001) investigates whether there is systematic management of accounting earnings in response to a particular regulatory regime (incentive regulation vs. rate regulation) and realized performance relative to allowed return. His study was motivated by D'Souza (1998) who finds that when an accounting change that reduces income is mandated (e.g., SFAS 106), rate-regulated utilities managers tend to exercise discretionary choices so that the impact of the accounting change on financial statement is accentuated. The major question that Paek investigates is whether a regulatory regime enhances opportunities for earnings management. He draws his pre-1994 utility sample from the U.S. Energy Information Administration (EIA) data base that lists major electric utilities. He categorizes utilities as under either incentive or rate-regulation regimes basing this classification on an unpublished work by Landon (1993). In univariate tests, he estimates discretionary accruals (the earnings management metric) using a modified Jones (1991) model. He modifies the original Jones (1991) model by including allowed rate of return (AROE) as an additional independent variable. In multivariate tests, the dependant variable, discretionary accrual (DA) is regressed on test variables (rate-regulated overearning, rate-regulated underearning, incentive-regulated overearning, and incentive-regulated underearning) and control variables. He finds that rate-regulated overearning firms make the most income-decreasing accruals.

I extend Paek (2001) by conducting a comprehensive study of earnings management in the US electric utility industry. Unlike Paek (2001), I omit AROE from discretionary accrual models because it is determined by regulators. Paek (2001) examines the pre-1994 period, I focus on a more current period (1994-2005). Finally, the research questions that my study addresses are entirely different from Paek's.

In a more recent work, Gill-de-albornoz and Illueca (2005) investigate earnings management in the Spanish electricity industry. They examine whether electric utility managers artificially reduce reported earnings after the government establishes tariff (rate) increases. These researchers base their study on positive economic theory of regulation which proposes that political powers may transfer wealth between various parties (Stigler 1971, and Peltzman 1976). The political cost hypothesis (Watts and Zimmerman 1986) states that the more a firm is subject to potential wealth transfers as a result of the political process, the more its management is likely to adopt accounting policies that reduce such transfers. Gill-de-albornoz and Illueca (2005) study a sample of thirteen Spanish electricity utilities over a ten year period (1991-2001). The earnings management metric in their study is discretionary accruals which they compute using; the Jones (1991) model, the Jones modified Cash flow model[27], and working capital accrual models. They adopt Cahan's (1992) one-way fixed effects model specification to examine the relation between discretionary accruals and the test variable TARRIFNOM, the nominal change in the electricity tariff approved by the government in year *t* for the following year *t+1*. The researchers find that discretionary accruals in Spanish electricity companies are inversely related to the annual approved tariff change, which suggests that the accrual policy of sample firms is conservative (aggressive) when an increase (decrease) in tariffs is approved. Gill-de-albornoz and Illueca (2005) interpret their findings to mean that after the government increases electricity tariffs, utilities manage earnings downward in order to diminish political visibility, and dampen public opposition that often follows a government-approved tariff increases. Although the

[27] Cash flow from operations are included in the model in order to control for extreme performance

electric utility industry in Spain significantly differs from that of the U.S.[28], the Spanish experience motivates this study to examine whether U.S. electric utilities manage earnings.

The preceding literature reveals that firms in U.S. regulated industries may manage earnings. Furthermore, firms in the U.S. rate-regulated may manage earnings (Paek 2001), this would be consistent with international evidence drawing from Spanish utility industry (Gill-de-albornoz and Illueca (2005). This review also reveals that the FASB by issuing SFAS 71 provides rate-regulated utilities more discretion in accrual accounting than non rate-regulated firms. An empirical question is whether electric utility firms in the U.S. rate-regulated electric industry manage earnings more, or less, than non-regulated firms. If regulated electric utilities manage earnings more than non-regulated firms, then I would expect discretionary accruals of regulated electric utilities to be greater in magnitude than those for non-regulated companies. The argument for rate-regulated electricity firms to manage earnings more than non-regulated firms is that utilities are given greater discretion to book and amortize accruals under the provisions of SFAS 71. For instance, an electric utility may depreciate certain capitalized costs (e.g. damage resulting from natural disasters) over a nominally lengthy period of time in order to recover the costs through a temporary surcharge. Therefore the opportunity to affect accruals through the application of SFAS 71 suggests that electric utilities may have more discretion to manage earnings. However, the counterpoint to this proposition is that electric utilities may, in fact, have less discretion. This argument stems from the fact that unlike other companies, the earnings of rate-regulated electric utilities are not only closely monitored by conventional financial statement users (e.g. investors, creditors, financial analysts, and financial reporting oversight agencies), but are also scrutinized by federal and state utility regulators. Utility

[28] For instance, In Spain adjustments to electricity tariffs are approved by the government while in the US electric rates are approved by public utility commissions.

managers who decide to manipulate earnings face an increased risk of having their actions discovered and therefore, should be more conservative in making accrual decisions than managers of non-regulated companies.

The preceding discussion presents two opposing arguments. As suggested by extant earnings management research, regulatory constraints may provide more incentives for rate-regulated electric utilities to manage earnings with discretionary accruals than non-regulated companies. Additionally, rate-regulated utilities can apply SFAS 71, which provides more discretion over accruing/depreciating capitalized costs. Alternatively, regulated utilities may have smaller levels of discretionary accruals than unregulated companies because they are subject to additional scrutiny by regulators. Because of these contrasting arguments, the first hypothesis is presented in the null form:

H_1: There is no difference between the magnitude of the discretionary accruals of rate-regulated electric utilities and those of comparable non-regulated companies.

2.6 Earnings Management and the Deregulation of the Electric Utility Industry

Investor-owned electric utilities in the U.S. have been rate-regulated for over 80 years (Tschirhart 1991). Until the 1980s, the U.S. electric utility industry consisted of vertically integrated firms with state-franchised monopolies. Federal regulatory agencies only played a minor regulatory role and competition was essentially non-existent. Rate regulation insulated utilities from competition and over that time the industry was transformed from small competitive producers to large uncompetitive producers. Large noncompetitive producers were thence awarded monopoly franchises by their state commissions, and in return accepted guaranteed rates for their obligations to serve all customers. The vertical integration of generation, transmission, and distribution enabled economies of scale.

The environment changed in the 1970s. Inflation soared, fuel prices skyrocketed, gas shortages were prevalent, cost overruns on new plant construction became common (particularly with nuclear plants) and environment concerns placed new constraints on utilities operations (Tschirhart 1991). State commissions were ill-equipped to handle these changes and to respond to associated public concern. In 1978, the U.S. Congress responded to these events by passing the Public Utility Regulatory Policy Act (PURPA). This statute included provisions that instructed the FERC to require utilities to purchase electricity from two statutorily-prescribed types of qualifying facilities (QFs) owned by third parties. PURPA demonstrated the effectiveness of an institutional framework in which utilities are required to transmit electricity generated by third parties-a necessary element in establishing a competitive wholesale market for electricity (Pierce 2005). PURPA and state statutes that permitted consumers to indirectly buy electricity from non-utility sources exposed the electric utility to competition for the first time. In order to survive in a more competitive environment, utilities had to become more efficient.

In the early 1990s, technological improvements in the generation of electricity (i.e., relatively inexpensive gas-turbine generating plants and natural gas) emboldened deregulatory forces within the electric utility industry. An independent power producer could construct a relatively inexpensive gas-fired generating plant in a relatively short period of time, and produce power at competitive prices to those charged by established utilities. Recognizing this shift in the regulatory landscape, Congress passed the Energy Policy Act of 1992 (EPACT 92), a statute that for the first time gave FERC the authority to require a utility to provide third party access to its transmission lines in what came to be known as " retail wheeling" (D'Souza and Jacob 2001). In effect, EPACT 92 created conditions necessary to support a competitive wholesale market for generation and marketing of electricity (Watkiss and Smith 1994). The 1992 statute deregulated wholesale prices of electricity, and provided States the opportunity to further deregulate at the retail level, all aimed at reducing electricity prices.

FERC implemented the intent of this legislation in 1996 by issuing Orders 888 and 889, with the stated objective to "remove impediments to competition in wholesale trade and to bring more efficient, lower cost power to the Nation's electricity consumers"(EIA 2006). These regulatory orders opened power transmission networks around the country, thereby enabling utilities' transmission lines to become common carriers. In the past, the owners of vertically integrated transmission facilities could deny access and transport across their lines. After Order 888, electrical generation competitors, in theory, could access transmission lines on the same rates, terms, and conditions as their utility owners. Orders 888 and 889 required every investor-owned utility to provide third party access to its transmission lines (FERC 1996). In return for providing third party access, FERC authorized each utility to make wholesale electricity available at unregulated prices.

As a result of Federal and state initiatives, the electricity power industry began moving away from an environment of highly regulated natural monopolies and toward a more competitive market for electricity. By 1999, deregulation for generation and marketing of electricity at the retail level had gained momentum. FERC aimed at creating competitive wholesale markets across the country with hope that states would follow suit and create competitive retail markets. Unfortunately, the California electricity crisis in the summer of 2000 cast doubt on deregulation efforts. The expectation that electricity prices would fall in California after introduction of retail competition did not occur. Joskow (2001), and Joskow and Kahn (2002) find that competition was inadequate in reducing prices and stabilizing the California market. Matters were further aggravated by Enron's collapse. These two events (the California market "melt down" and the Enron debacle) bolstered the positions held by opponents of electric utility deregulation. Deregulation and restructuring of electric utilities began to stall but did not completely come to a halt. By 2005, almost half of the states throughout the U.S. had passed major legislation to restructure[29] their electric power providers, with the ultimate goal of lowering electricity costs to consumers. However, these state-specific restructuring efforts were not uniform with respect to either the final form of deregulation adopted, or the implementation schedule executed in restructuring. States that historically had higher-than-average electricity rates, such as California, Pennsylvania, New York, and most of the New England states, opened their retail electricity markets to competition, allowing customers to choose their own electricity supplier. Some other states are implementing the process on a more measured basis. While some states have delayed beginning the process, others have decided not to restructure, but to retain the traditional rate-regulated utility model at the retail level.

Retail access, the major objective of restructuring, allows customers to choose their own supplier of power generation services. Note that retail deregulation only includes the generation and marketing of electricity, and does not include the transmission and distribution functions which will remain rate-regulated.

Government regulation (including rate regulation) of business has been strongly debated in academic circles. There are both proponents and opponents of Federal and state regulation of public enterprises. Positive accounting researchers (Leftwich 1980, and Watts and Zimmerman 1986) argue against government regulation by asserting that politicians use regulations as mechanisms to transfer wealth to themselves at the expense of consumers, and that the "public interest" justification employed by proponents of government regulation is a fallacy.

[29]Restructuring of electric utilities entails separating the heretofore combined generation, transmission and distribution functions that characterized these vertical monopolies into separate entities.

Alternatively, proponents of government regulation argue that, if natural monopolies are left unchecked, they can exploit consumers by either under-producing or inefficiently producing public goods in order to push up prices (Sappington 1980). The ultimate effect of unregulated monopolistic actions is the deterioration of social welfare. The degree to which the government regulates the free market continues to be a contentious issue. The U.S. deregulation experience has added to this debate.

Not withstanding the views of opponents to deregulation and the California experience, the above discussion reveals that abandoning rate regulation and introducing a competitive environment may benefit consumers through reduced electricity rates. States that eliminate their utilities' rate-regulated business models force power providers to compete in the marketplace for customers seeking lower rates. This should lead to increased cost efficiencies. Deregulation should also affect the opportunities for earnings management.

A change from regulation to deregulation introduces the concern for the regulatory treatment of "stranded costs". Loudder et al. (1996) define stranded costs as; "those costs that have been incurred by a public utility with the expectation that the regulator will allow for future recovery of the costs, but this recovery may be uncertain in a future regulatory environment" (p.358). Assets representing stranded costs include generating plants, costs that regulators have allowed for a variety of social purposes (e.g conservation and low-income assistance programs). After deregulation, recovery of these costs is uncertain, i.e., they become "stranded". Bhojraj et al. (2004) find that before regulators have established cost recovery mechanisms in their jurisdictions, firms with high levels of stranded costs tend to refrain from strategic disclosures about plans to exploit new opportunities made possible by deregulation. After regulatory concerns abate, firms exhibit an increase in the level of disclosures, diminished only by considerations related to product market competition. They further find that regulatory incentives do not influence voluntary disclosures about plans to counter the threat of revenue loss. Firms do not appear to anticipate more stringent regulatory decisions on the stranded cost issue if they reveal their plans to protect existing customer base. D'Souza and Jacob (2001) find a significant association between electric utility stock prices and estimates of utility stranded costs, suggesting that investors anticipate that a non-trivial portion of stranded costs will be borne by utility shareholders. Nunez (2007) documents a positive relation between stranded benefits and share prices.

The studies discussed above suggest that recovery of stranded costs is an issue in the aftermath of deregulation. Of particular interest is the finding that the market considers stranded costs to be non-trivial and the associated finding of a negative relation between share prices and stranded costs. After deregulation, utilities may have the incentive to manage earnings upwards in order to assure investors that stranded costs are not significantly affecting their earnings.

Regulatory accounting requires electric utilities that cease to be rate-regulated to immediately discontinue applying SFAS 71 in financial reporting. SFAS 101, "*Accounting for the* D*iscontinuance of Application of SFAS 71",* requires electric utilities to immediately write off any regulatory assets (deferred regulatory costs) that had been created (FASB 1988). The implication is that utilities operating in states that have restructured have reduced capacity for accrual management (i.e., SFAS 71). However, deregulation of the generation and marketing of electricity also brings a reduction in regulatory oversight, permitting managers increased earnings management opportunities. Additionally, with the price of electricity determined in the market rather than by regulatory bodies, managers may have increased incentives to manage earnings, i.e., revenues are no longer determined by regulators. For example, executive compensation in the electric utility industry provides stock option and bonus incentives similar to that observed for non-regulated firms, although smaller in magnitude.[30] Deregulation may increase the likelihood of opportunistic earnings management.

If deregulation provides greater opportunities for earnings management (albeit without the accrual provisions of SFAS 71), and increased incentives to manage earnings, then the earnings management metric should increase in magnitude for those utilities in states electing to restructure. I investigate this proposition by testing the following directional hypotheses:

***H_{2A}*: For those utilities in states electing to restructure, the magnitudes of discretionary accruals are significantly greater in the post-restructuring period than in the pre-restructuring period.**

***H_{2B}*: In the post-restructuring period, the magnitudes of discretionary accruals for utilities in states electing to restructure are significantly greater than those of utilities in states electing not to restructure.**

2.7 Earnings Management Associated with Requests for Rate Increases

The utility's decision to file for a rate increase depends on the growth rate of earnings achieved by the utility in the current and previous year, the level of interest coverage realized in the current year, and a variable that measures prior expectations of success in the PUC's deliberation process (Joskow 1973). The financial indicator that seems to be of most interest to the regulators in rate approval process is the growth rate in earnings (Joskow 1973). Jaskow's findings suggest that negative or lower earnings growth rates serve as important economic

[30] Dismukes and Hughes (2006) report the mean total compensation paid electric utility CEOs in their sample of 31 firms was $5.5M in 2004. Their $3M median for utility CEOs is well above the $2.4 million median in total compensation for CEOs at 1,522 of the largest U.S. corporations. As a percentage of total compensation, utility CEOs' salaries decreased from 54 percent in 1994 to approximately 14 percent in 2004. Simultaneously, the proportion of total compensation paid in exercised stock options increased from approximately 25 percent to nearly 69 percent during the same period.

arguments for rate increases. Sappington (1980) argues that a regulated utility may engage in strategic behavior to enhance long-run earnings and the regulator is unable to detect and control a wide range of strategic behavior by a regulated firm. Hagerman (1990) documents that regulators can not prevent utilities from maximizing profits because they do not know information about firms costs. He argues that due to asymmetrical information, a regulated firm has superior knowledge of costs compared to regulators. Hagerman (1990) suggests that management may attempt to manipulate the rate request-process by either padding expenses in a given period to relax "future periods" constraints, or by deliberately seeking to incur losses, and therefore realizing negative earnings growth rates in an effort to relax regulatory control (including obtaining approval of rate increases). Sherman (1989) argues that utilities expend significant effort in developing valid arguments and supporting documentation to justify rate increases. Accounting earnings generated through the accrual process provide the most important economic justification for increasing electricity rates. Utilities that petition for rate increases are required to submit detailed cost and revenue data to support their requests. Prior studies find that managers exercise significant discretion in reporting accounting earnings (Healy 1985, Jones 1991, and Kothari et al. 2005). Utility managers may have incentives to manipulate earnings prior to requesting a rate increase, and regulators may not be effective in detecting strategic cost/earnings manipulation (Hagerman 1990, Sherman 1989, and Sappington 1980). Prior studies find that regulators' skills may be limited and their resources inadequate to properly assess strategic behavior or inefficiencies in utilities' production decisions (Kahn 1973, and Sappington 1980).[31]

[31] A noteworthy example of this is Enron's demonstrated ability to manipulate the California electricity market during 2000-2001.

At the managerial level, private incentives may exist for managers to manipulate earnings in order to circumvent regulatory oversight. Abdel-Khalik (1988) observes that incentives exist for implicit contracts to reward managers for their innovativeness in successfully obtaining favorable outcomes from a rate case (i.e., a rate increase). In addition, the compensation contract may motivate earnings management. If an increase in rates is achieved, a manager may meet the earnings target for a bonus (Healey 1985). To the extent that managers are compensated for a successful rate increase, they should have incentives to artificially dampen earnings by using income-decreasing accruals during those periods in which a rate increase is requested. Such action would tend to increase the probability of the requested rate hike being approved. Gill-de-albornoz and Illueca (2005) find that electric utility companies in Spain manage earnings down after the government has approved a tariff increase in order to mitigate political costs. Paek (2001) finds that electric utility companies in the U.S. that are under rate regulation make significantly greater income-decreasing accounting choices. Although he did not investigate the issue empirically, Paek (2001) opined that utility managers might exercise discretion opportunistically to decrease earnings, thereby exaggerating poor performance, to obtain approval to increase rates. I extend Paek (2001) study by investigating whether managers of rate-regulated electric utilities manage earnings downward in the year they petition for rate increases in an effort to obtain regulatory approval for rate requests. For publicly traded companies, especially those that are more heavily followed by analysts, an opposing argument can be made that companies have more incentives to manage earnings upward rather than downward. Dechow and Skinner (2000) find that managers have become increasingly sensitive to the level of their firms' stock prices and to key accounting numbers such as earnings. Consequently, managerial incentives to manage earnings upward in order to maintain or improve stock prices have also increased. However, these stock market incentives are probably less significant in a rate-regulated industry.

The preceding discussion supports the position that utility managers have incentives to artificially decrease earnings during those periods in which they submit requests for rate increases to regulatory bodies. I investigate this proposition by testing the following directional hypothesis:

H_3: The magnitude of discretionary accruals is significantly less for those electric utilities in the year in which they request a rate increase, than for the same utilities in those years in which a rate increase is not requested.

3. SAMPLE SELECTION, MODEL SPECIFICATION AND RESEARCH DESIGN

3.1 Sample Selection

This study uses two independent samples. To construct sample one for testing Hypotheses 1 and 2, I begin with all COMPUSTAT firms in the U.S. electric utility industry (SICs 4911 and 4931). I eliminate foreign firms (ADRs), private firms, and then to ensure I am examining the nation's primary electric utilities, I limit the sample to only those firms that are members of the U.S. electric utility industry's largest trade association, the Edison Electric Institute (EEI). Note that electric utilities are frequently organized as holding companies and subsidiary operating companies; the latter actually produce and sell electricity. Using EEI membership information, I classify those COMPUSTAT firms that are listed as subsidiaries of concurrently listed holding companies; if both the holding and its subsidiary or subsidiaries are concurrently listed, I drop the holding company, as its financial data is simply a consolidation of subsidiaries'. Focusing on operating companies is also advantageous in that these subsidiaries are generally located within a single state's regulatory jurisdiction, simplifying the classification process needed to test Hypothesis 2. The sample, therefore, consists of operating companies and those holding companies without COMPUSTAT-listed subsidiaries. Finally, because a time series research design is used in testing Hypothesis 1, I eliminate companies without complete data for the 1994-2005 sample period. The sample period starts in 1994 because I assume that the Energy Policy Act of 1992 deregulating the wholesale market for electricity began to change the utilities' operating environment by that year. Furthermore, Paek (2001) investigates pre-1994 sample period and this study extends Paek's by focusing on post-1994 period. Table 1 provides a list of investor-owned rate-regulated electric utility firms and matched non-regulated control firms that constitute sample one.

Table 1
Investor-Owned Rate-Regulated Electric Utility Firms and Matched Control Firms

Utility Firm	Control Firm	Utility Firm	Control Firm
Alabama Power Co	PEPSI Inc.	KEYSPAN Corp	WYETH
Appalachian Power	PEPSI Bottling Group Inc	Metropolitan Edison	ARVINMERITOR Inc
AQUILA Inc	Advanced Micro Devises	Mississippi Power	ATMEL Corp
Arizona Public Service Co	Union Carbide Corp	Northern Indiana PUB SERV CO	Emerson Electric Co
AVISTA Corp	Newell Rubbermaid Inc	Northern States Power/WI	Stanley Works
Cleveland Electric ILLUM	Crown Holdings Inc	Northwestern Corp	AVX Corp
Commonwealth Edison Co	Motorola Inc	NSTAR	Valero Energy Corp
Consolidated Edison Inc	Weyerhaeuser Co	Ohio Edison Co	Deere & Co
Consumers Energy Co	Abbott Laboratories	Otter Tail Corp	Integrated Devise Tech Corp
Dayton Power & Light Inc	Owens Corning	PACIFICORP	Merck & Co
Detroit Edison Co	Eastman Kodak Co	Pennsylvania Electric Co	NORBORD Inc
Dominion Resources Inc	Intel Corp	Pennsylvania Power Co	Pall Corp
Duke Energy Corp	Intl paper Co	PNM Resources Inc	Timken Co
Duquesne Light Co	Nucor Corp	Progress Energy Inc	ALCAN Inc
El Paso Electric Co	AMKOR Technology Inc	Public Service Co of COLO	Sunoco Inc
Entergy Arkansas	Kellogg Co	Public Service Co/NH	Applied Materials Inc
Entergy Louisiana Holdings	Sara Lee Corp	Sierra Pacific Power Co	Reynolds American Inc
Entergy Mississippi	Longview FIBRE Co	Southwestern Electric PWR Co	Thomas Corp
Gulf Power	Avery Dennison Corp	Southwestern Public SVC Co	Sun Microsystems Inc
Hawaiian Electric INDS	Cummins Inc	UIL Holdings Corp	PEPSIAMERICAS Inc
Indiana Michigan Power	Bowater Inc	UNISOURCE Energy Corp	ITT Industries
Kentucky Power	Fairchild Semiconductor INTL	Western Massachusetts El Co	POLYONE Corp
Kentucky Utilities Co	Lafarge North America Inc	Wisconsin Energy Corp	PPG Industries Inc
		Wisconsin Power and Light	Maxxam Inc

Because Hypothesis 1 requires comparing the discretionary accrual metric of rate-regulated electric utilities with comparable non-regulated companies, I follow Nwaeze (1998), in selecting a matched sample of manufacturing firms (SICs 2000 to 3990). The matching process first requires identifying the period for which data are available for a utility, then matching the utility with a non-regulated firm based on the value of gross property, plant and equipment (PPE)[32]. The process is repeated until all electric utilities are matched by non-regulated manufacturing firms.

These sample selection procedures result in a final sample one of 1,128 firm-year observations. Table 2 Panel A provides the distribution of firm-year observations of sample one. For time series tests of Hypothesis 1, the observations are distributed as follows; estimation period (1994 – 2001); 752 observations, and event period for prediction of earnings management (2002 – 2005) 376 observations.

The sample for testing Hypothesis 2 is derived by parsing sample one into two groups according to deregulation status after 1999, when most states passed enabling legislation for the restructuring of electric utilities operating in their states. I use a COMPUSTAT variable "STATE" to search the data base for the state where the utility is registered and conducts business operations. Table 2 Panel B reports the distribution of firm-year observations of the deregulated sample. Firm-year observations of deregulated utilities for testing Hypothesis 2 are distributed as follows: pre-deregulation period (1994-1999), 182 observations; and, post-deregulation period (2000-2005), 130 observations. The number of observations for all utilities in sample one in post-deregulation period (2000 – 2005) is 282 (Table 2 Panel B). The list of sample one firms categorized according to deregulation status is presented in Table 3.

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[32] Matched control firms are selected on the basis of gross Property, Plant and Equipment (PPE) because electric utilities are capital intensive. Nwaeze (1998) selects matches on the basis of total assets.

Table 2
Sample Selection and Distribution of Firm-Year Observations

Panel A: Sample One: Shareholder-Owned Electric Utilities

	Firm-Years
Total No. of Electric Utilities in COMPUSTAT (SICs 4911 and 4931)	3,648
ADRs	(315)
Non Shareholder-owned	(1,161)
Listed members of Edison Electric Institute (EEI)	2,172
Holding companies with concurrently listed subsidiaries	(624)
Firms with insufficient data on COMPUSTAT	(984)
Final Sample of Operating Shareholder-owned Electric Utilities	564
Matched manufacturing control firms (SIC 2000-3990)	564
Final sample	1,128

Distribution of Observations Across Estimation Period and Event Period

Estimation period (1994-2001)	
Utilities	376
Control Firms	376
Total	752
Event period (2002-2005)	
Utilities	188
Control Firms	188
Total	376

Panel B: Distribution of Observations as to Deregulation Status

Deregulated Only:	
Pre-deregulation period (1994-1999)	182
Post-deregulation period (2000-2005)	130
Total	312
Both regulated and deregulated:	
Post-deregulation period(2000-2005)	282

Panel C: Sample two: Electric Utilities Requesting Rate Increases - 1994-2005

	No. of Firm Years	
	No rate increase requested	Rate increase Requested
Regulatory Research Associates, Inc listed firms that are EEI members	408	92
Outliers trimmed at abs (dffits)<1 and abs (rstudent)<2	(12)	(2)
Final Sample	396	90

Table 3
Electric Utility Firms in Sample One Categorized According to Deregulation Status of Generation and Marketing Functions

Deregulated	Not Deregulated
Appalachian Power	Alabama Power Co
Arizona Public Service Co	Progress Energy Inc
Entergy Arkansas	Duke Energy Corp
NSTAR	Gulf Power
Consolidated Edison Inc	Hawaiian Electric INDS
Dominion Resources Inc	Indiana Michigan Power
El Paso Electric Co	Kentucky Power
KEYSPAN Corp	Entergy Louisiana Holdings
Metropolitan Edison	Entergy Mississippi
PACIFICORP	Northern States Power/WI
Pennsylvania Electric Co	Northwestern Corp
Pennsylvania Power Co	Otter Tail Corp
Public service Co/NH	PNM Resources Inc
Sierra Pacific Power Co	AQUILA Inc
Southwestern Electric PWR Co	AVISTA Corp
Southwestern Public SVC Co	Wisconsin Energy Corp
UNISOURCE Energy Corp	Wisconsin Power & Light
UIL Holdings Corp	Northern Indiana PUB SERV Co
Western Massachusetts EL Co	Kentucky Utilities Co
Cleveland Electric ILLUM	Public Service Co of COLO
Dayton Power & Light Inc	Mississippi Power
Consumers Energy Co	
Duquesne Light Co	
Commonwealth Edison Co	
Detroit Edison Co	
Ohio Edison Co	

In testing Hypothesis 3, whether utilities depress earnings during those periods in which they request rate increases, I draw a new sample (sample two) from a database obtained from Regulatory Research Associates, Inc. This database provides information on all major rate case decisions from 1990 to 2005.

To construct sample two, I obtain dates for rate requests for only shareholder-owned electric utilities and limit the sample period from 1994 to 2005. As stated previously, I do not use years prior to 1994 (except for sensitivity and robustness tests) because I assume that the Energy Policy Act of 1992 changed utilities' operating environment after its passage. As in sample one accounting data are collected from COMPUSTAT, and the sample is winsorized at dfitts<1 and abs(r-student) <2 which approximates to 1 and 99 percent distribution levels, to eliminate outliers. The sample selection procedure results into 486 firm-year observations that are distributed as follows; no rate increase requested 396; rate increase requested 90 (Table 2 Panel C). Note that sample two consists of utilities that requested a rate increase in at least one of the twelve-year sample period; the magnitude of discretionary accruals for firm-years in which rate requests are made are compared to those for firm-years in which no rate increase is requested. Table 4 reports the list of utilities that requested rate increases at least once during the study period (1994-2005). Because I perform robustness and sensitivity tests for the companies in this sample, I relax the sample period to include 1993 and eliminate those electric utilities that issue stock.

I conduct additional tests on this sample to examine the possible use of industry-specific GAAP to manage earnings. The test requires data on regulatory assets. I hand collect these data from financial statements' information provided in SEC form 10K filings.

Table 4
Investor-Owned Rate-Regulated Electric Utilities that Requested for a Rate Increase at Least Once, During the Period 1994-2005

AEP Texas Central	Consolidated Edison Co of NY	Gulf Power	Ohio Edison Co
AEP Texas North Co	Consumers Energy Co	Hawaiian Electric Co	Pacific Gas & Electric Co
AMEREN Corp*	Delmarva Power & Light Co	Idaho Power Co	PACIFICORP*
Appalachian Power	Duke Energy Corp*	Indiana Michigan Power	PSI Energy Inc
AQUILA Inc*	El Paso Electric Co*	Interstate Power & Light Co	Public Service Co/NH
Arizona Public Service Co	Entergy Arkansas	Kentucky Utilities Co	Public Service Co of COLO*
AVISTA Corp*	Entergy Gulf States	Madison Gas & Electric Co	Public Service Co of OKLA
Baltimore Gas & Electric Co	Entergy Louisiana Holdings	MidAmerican Energy Co*	Public Service Co of New MEX
Black Hills Power Inc	Entergy Mississippi	Mississippi Power	Puget Sound Energy Inc
Central Hudson Gas & ELECTR	Entergy New Orleans	Nevada Power Co	Rochester Gas & Electric Corp
Central Maine	Florida Power Corp	New York St ELEC & GAS Corp	Sierra Pacific Power Co
Central Vermont PUB SERV*	Florida Power & Light Co	Northern States Power/WI	Southern California Edison
Commonwealth Edison*	Georgia Power	Northwestern Corp*	Tampa Electric Co
			Wisconsin Electric Power Co
			Wisconsin Public Service Co*

* Are not subsidiary operating companies; these firms issue stock unlike subsidiaries in which equity is issued by the holding company. Companies with asterisks are excluded during sensitivity testing aimed at investigating the robustness of rate increase incentive results to competing capital market incentives for earnings management.

3.2 Research Design and Model Specification

3.2.1 Tests of Hypothesis 1

Accounting researchers have adopted several models in estimating the discretionary accrual metric for earnings management. Dechow and Sloan (1991) use an industry model that specifies non-discretionary accruals as a function of the median total accruals in the industry. Their model assumes that accruals are largely driven by industry-specific practice. The random-walk model (Healy 1985, and DeAngelo 1986) estimates discretionary accruals as the difference between accruals at a given time and their average over time. The most commonly applied time-series Jones model (Jones 1991) and modified Jones model (Dechow et al. 1995) specify total accruals as a linear function of variables that affect accruals, such as change in revenues, and gross property, plant and equipment. The residual of this regression is a measure of discretionary accruals. Kang and Sivaramakrishnan (1995) derive an instrumental variables model to mitigate the potential effects of simultaneity in the income-generating and accruals-generating processes. Dechow and Jiambalvo (1994), among others, make modifications to the Jones (1991) model in a bid to adapt it to cross-sectional settings. Defond and Subramanyam (1998) argue that not all sales are non-discretionary as implied in the Jones (1991) model. Their argument stems from the fact that accounting earnings can be managed by shifting credit sales between periods. They accordingly modify the Jones (1991) model by offsetting accounts receivable from sales. Therefore, their model also assumes that all accounts receivable are managed. Dechow et al. (1995) find that all accrual estimation models are misspecified for firms with extreme performance. Although all accrual models are reported to measure discretionary accruals with error, Kothari et al. (2005) find that the original Jones (1991) and the modified Jones model that includes return on assets (ROA) as a control for extreme performance are better specified than the others in estimating discretionary accruals. Control for extreme performance as suggested by Kothari et al. 2005 may not be appropriate for rate-regulated electric utilities because rate of return is regulated, i.e., the rate is predetermined by regulators. Gill- de-Albonorz and Illueca (2005), Phillips et al. (2003), Kaznik (1999), and Jeter and Shivakumar (1999) include cash flow from operations (CFO) as a control variable to mitigate the effect of extreme performance. Because of the lack of precision of individual accrual models in estimating discretionary accruals as discussed above, prior researchers have employed multiple discretionary accrual models in earnings management studies (e.g., Gill- de-Albonorz and Illueca 2005, Kothari et al. 2005, and Jones et al. 2006).

Arising from the above discussion, I apply the Ordinary Least Squares (OLS)[33] regressions to determine the earnings management metric, discretionary accrual by estimating the following models:

$$\mathbf{TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta SALES_t + \beta_2\ PPE_t + \varepsilon_t} \quad \textbf{[Jones Model]} \qquad \textbf{(1)}$$

$$\mathbf{TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ (\Delta SALES_t - \Delta REC_t) + \beta_2\ PPE_t + \varepsilon_t} \quad \textbf{[Modified Jones]} \qquad \textbf{(2)}$$

$$\mathbf{TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta\ SALES_t + \beta_2\ PPE_t + \beta_3\ CFO_t + \varepsilon_t} \quad \textbf{[Jones +CFO Model]} \qquad \textbf{(3)}$$

$$\mathbf{TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ (\Delta\ SALES_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3 CFO_t + \varepsilon_t} \quad \textbf{[Mod. Jones + CFO]} \qquad \textbf{(4)}$$

Where: [denotes COMPUSTAT data element number]:

TAC = Total Accruals [Data 18 – Data 308];

ΔSALES = Change in Sales [Data 12];

ΔREC = Change in Accounts Receivable [Data 2]

PPE = Gross Property, Plant and Equipment [Data 7]; and

CFO = Cash flow from Operations [Data 308].

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[33] All models estimated in this study are based on OLS analysis based on the assumption that there is a linear relationship between dependent and independent variables and that the dependent variable in each regression is continuous.

Following prior studies that investigate discretionary accruals (e.g., Dechow et al. 1995, Defond and Subramanyam 1998, Dechow et al. 2003, and Phillips et al. 2003), I scale all variables in the models by lagged total assets [Data 6] in order to mitigate heteroskedasticity in the residual.

Models 1 through 4 are used to test Hypothesis 1 in two different research designs. First, I perform time series regressions, consistent with Jones (1991) methodology. Second, I perform annual and pooled cross-sectional regressions with one-way fixed effects model following Cahan (1992).

Because Hypothesis 1 requires the estimation of the actual magnitudes of discretionary accruals for two sets of firms, a time series research design, i.e., Jones (1991), is appropriate. Since prior researchers have excluded regulated utilities from their samples, the magnitude of discretionary accruals for rate-regulated utilities presents an empirical question. Following the Jones (1991) methodology, I estimate the firm-specific coefficients for Models 1 – 4, using an eight-year estimation period (1994 -2001). I then use the estimated coefficients from the estimation period to compute discretionary accruals in a four-year event period (2002 – 2005). Discretionary accruals are residuals from the regressions. After computing mean discretionary accruals for both the sample of electric utilities and the control sample of manufacturing firms, I then perform statistical tests to determine if their magnitudes are significantly different.

Jones' (1991) time series research design, because of the requirement for a long time series, has been criticized for allowing serial correlation and survivorship bias to potentially affect the estimation process (DeFond and Jiambalvo 1994). Because of this, most researchers have adapted their discretionary accrual models following Jones (1991) to incorporate cross-sectional research designs. In order to corroborate results of time series tests, I estimate the following cross-sectional models.

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\ \mathbf{\Delta SALES_t} + \boldsymbol{\beta_2}\ \mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{RATE\_REG_t} + \boldsymbol{\varepsilon_t} \quad \mathbf{(5)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\ \mathbf{(\Delta SALES_t - \Delta REC_t)} + \boldsymbol{\beta_2}\ \mathbf{PPE_t} + \boldsymbol{\beta_3}\ \mathbf{RATE\_REG_t} + \boldsymbol{\varepsilon_t} \quad \mathbf{(6)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\ \mathbf{\Delta\ SALES_t} + \boldsymbol{\beta_2}\ \mathbf{PPE_t} + \boldsymbol{\beta_3}\ \mathbf{CFO_t} + \boldsymbol{\beta_4}\ \mathbf{RATE\_REG_t} + \boldsymbol{\varepsilon_t} \quad \mathbf{(7)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\mathbf{(\Delta\ SALES_t - \Delta REC_t)} + \boldsymbol{\beta_2}\mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{CFO_t} + \boldsymbol{\beta_4}\mathbf{RATE\_REG_t} + \boldsymbol{\varepsilon_t} \quad \mathbf{(8)}$$

These models are specified basing on Cahan (1992), where the cross-sectional variables are defined as in Models 1-4 with the following exceptions: (1) Because the discretionary accrual metric is not conditioned on an event from which direction may be hypothesized, I use the absolute value of total accruals ($|TAC_t|$) as the dependent variable; (2) I introduce the indicator variable *RATE_REG*, which equals one for observations of rate-regulated utilities, and zero otherwise. Again, all continuous variables are scaled by lagged total assets. I use these models to carry out a two-tailed test for the statistical significance of *RATE_REG's* coefficient, as there are plausible arguments as to why the sign of the coefficient could either be positive or negative. In addition to annual regressions, I estimate a one-way fixed effects model by pooling all observations and incorporating dummy variables ($\sum \alpha_j YDUM_t$) to control for specific year effects. Because a single-industry sample may exhibit cross-sectional dependence, I estimate models using pooled observations with fixed time effects. Following Fama and MacBeth (1973), I also use the means of the twelve annual cross-sectional coefficients and the time series standard error to test the significance of variable *RATE_REG*.

3.2.2 Tests of Hypothesis 2

Hypothesis 2 examines if there were any changes in the magnitude of discretionary accruals associated with the restructuring of the electric utility industry in the late 1990s, when some states implemented retail deregulation of utilities' generation and marketing functions. Such a change might indicate an unintended consequence associated with deregulation, if relaxed regulatory oversight provided increased opportunities for earnings management. Limiting the sample only to electric utilities, I estimate the original Jones model and its modified versions (models 1 through 4) to examine discretionary accruals using Cahan's (1992) cross-sectional design. For cross-sectional tests, I first split the sample period into pre- and post-deregulation periods using the year 1999 as the benchmark year. Although some deregulation occurred prior to 1999, the preponderance of implementation started after that date. Because of the reduced observations from limiting the sample, I pool observations and add dummy variables for years in estimating the following one-way fixed-effect models to test Hypothesis 2_A:

$$\left|\mathbf{TAC_t}\right| = \alpha\ (1/\mathbf{ASSETS_{t-1}}) + \beta_1\ \Delta\mathbf{SALES_t} + \beta_2\ \mathbf{PPE_t} + \beta_3\mathbf{POST_t} + \sum\alpha_{,j}\mathbf{YDUM_t} + \varepsilon_t \tag{9}$$

$$\left|\mathbf{TAC_t}\right| = \alpha\ (1/\mathbf{ASSET_{t-1}}) + \beta_1\ (\Delta\mathbf{SALES_t} - \Delta\mathbf{REC_t}) + \beta_2\ \mathbf{PPE_t} + \beta_3\ \mathbf{POST_t} + \sum\alpha_{,j}\mathbf{YDUM_t} + \varepsilon_t \tag{10}$$

$$\left|\mathbf{TAC_t}\right| = \alpha\ (1/\mathbf{ASSETS_{t-1}}) + \beta_1\ \Delta\ \mathbf{SALES_t} + \beta_2\ \mathbf{PPE_t} + \beta_3\ \mathbf{CFO_t} + \beta_4\ \mathbf{POST_t} + \sum\alpha_{,j}\mathbf{YDUM_t} + \varepsilon_t \tag{11}$$

$$\left|\mathbf{TAC_t}\right| = \alpha\ (1/\mathbf{ASSETS_{t-1}}) + \beta_1\ (\Delta\ \mathbf{SALES_t} - \Delta\mathbf{REC_t}) + \beta_2\ \mathbf{PPE_t} + \beta_3\ \mathbf{CFO_t} + \beta_4\ \mathbf{POST_t} + + \sum\alpha_{,j}\mathbf{YDUM_t} + \varepsilon_t \tag{12}$$

Where: the variables are as defined in Models 1 - 4, and $\sum\alpha_{,j}YDUM_t$ are dummy variables for years minus one. In addition, the indicator variable *POST* is introduced; *POST* is equal to one for years 2000 to 2005 and zero otherwise (1994-1999). If deregulation leads to increased opportunities for earnings management, I would expect the coefficient for *POST* to be positive.

I then test whether any changes observed between the pre- and post-deregulation periods did not result from changes in the operating environment not associated with deregulation. Considering only those observations for year 2000 and later (the deregulated period), I parse the sample into those utilities in states that have implemented retail deregulation and utilities in those states that have not. Because of the reduced observations, I pool observations and add dummy variables for years in estimating the following one-way fixed-effect models to test Hypothesis 2_B:

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\ \mathbf{\Delta SALES_t} + \boldsymbol{\beta_2}\ \mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{DEREG_t} + \sum \boldsymbol{\alpha_{,j}}\mathbf{YDUM_t} + \boldsymbol{\varepsilon_t} \qquad \mathbf{(13)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\ \mathbf{(\Delta SALES_t - \Delta REC_t)} + \boldsymbol{\beta_2}\mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{DEREG_t} + \sum \boldsymbol{\alpha_{,j}}\mathbf{YDUM_t} + \boldsymbol{\varepsilon_t} \qquad \mathbf{(14)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\mathbf{\Delta SALES_t} + \boldsymbol{\beta_2}\mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{CFO_t} + \boldsymbol{\beta_4}\mathbf{DEREG_t} + \sum \boldsymbol{\alpha_{,j}}\mathbf{YDUM_t} + \boldsymbol{\varepsilon_t} \qquad \mathbf{(15)}$$

$$\left| \mathbf{TAC_t} \right| = \boldsymbol{\alpha}\ \mathbf{(1/ASSETS_{t-1})} + \boldsymbol{\beta_1}\mathbf{(\Delta\ SALES_t - \Delta REC_t)} + \boldsymbol{\beta_2}\mathbf{PPE_t} + \boldsymbol{\beta_3}\mathbf{CFO_t} + \boldsymbol{\beta_4}\ \mathbf{DEREG_t} + \sum \boldsymbol{\alpha_{,j}}\mathbf{YDUM_t} + \boldsymbol{\varepsilon_t} \qquad \mathbf{(16)}$$

Where variables are as defined in Models 1 – 4. In addition, the indicator variable *DEREG* is introduced; *DEREG* is equal to one for utilities in those states that have implemented retail deregulation, and zero otherwise. If deregulation leads to increased opportunities for earnings management, I would expect the coefficient for *DEREG* to be positive.

3.2.3 Tests of Hypothesis 3

In testing Hypothesis 3, I limit my sample to electric utilities that have requested a rate increase in at least one year of the eleven-year sample period. Discretionary accruals for firm-years in which a rate release was requested are compared to firm-years in which no request was made. The same firm will appear in both firm-year classifications, but not in the same year.

To address potential alternative explanations, I employ multivariate cross-sectional analysis to control for those factors identified in prior research to be associated with levels of discretionary accruals. However, some of these determinants used in prior earnings management studies are not applicable to the specification of models used in this research. These exceptions are discussed below.

DeAngelo (1981) provides the theoretical arguments for the requirement to control for audit quality, and Morsfield and Tan (2006) include an indicator variable to differentiate between big-five and non-big five auditors to control for audit quality in estimating discretionary accruals. They argue that larger sized audit firms (the big five audit firms) provide higher quality audit services, and therefore are more likely to inhibit earnings management. However, all of the electric utilities in this study's sample two (used to test H_3) employ big-five auditors, so the use of this determinant is moot.

Kothari et al. (2005), and Morsfield and Tan (2006) include return-on-assets (ROA) as a control variable, arguing that more profitable firms, with higher ROAs, are expected to have higher discretionary accruals. Because *ROA* is specified for rate-regulated electric utilities, I do not include it in specifying a multivariate model. Other potential control variables found in prior literature, including variables representing equity issues and institutional holdings, are also not applicable to this study because the majority of operating companies in the utility sample do not issue equity. This said, the following determinants of discretionary accruals are incorporated in specifying the multivariate model;

<u>Firm size</u>: Ashbaugh et al. (2003), and Butler et al. (2004) find that size (*SIZE*) is negatively related to discretionary accruals. I use the natural log of total assets as the measure of firm size.

<u>Cash Flows</u>: I include cash flow from operations (*CFO*) because prior research has shown that *CFO* is negatively related to discretionary accruals (Becker at al. 1998, Chung and Kallapur 2003, and Frankel et al. 2002).

<u>Growth:</u> Growth has been found to be positively associated with discretionary accruals (Menon and Williams 2004). High-growth firms are believed to have incentives to meet or beat

earnings benchmarks; hence, a positive relationship between growth and discretionary accruals is expected. A popular measure for growth is the market-to-book ratio. However, since the study's sample includes operating companies that do not issue equity, I follow Morsfield and Tan (2006) and use change in sales as a growth measure (*GROWTH*).

Lagged total accruals: Firms with larger absolute values of totals accruals may also have larger discretionary accruals (Becker et. al (1998). Therefore, I include lagged total accruals (*TAC*) as a control variable.

Leverage: I control for leverage because companies with high debt levels have greater incentives to use accruals to increase earnings in order to avoid violating debt covenants (Dechow and Jiambalvo 1994). Leverage is measured as total debt / total assets. A positive association is predicted between leverage (*LEV*) and discretionary accruals.

To test Hypothesis 3, that those utilities requesting rate increase have significantly less discretionary accruals in the year of the request than utilities not requesting increases, I first estimate models 1, 2, 3 and 4 using a cross-sectional research design to obtain signed discretionary accruals (*DACC*) for each model. I then estimate the following multivariate model year-by-year and pooled in a one-way fixed-effects model.

$$\mathbf{DACC_t = \alpha + \beta_1 REQ_t + \beta_2 CFO_t + \beta_3 TAC_{t-1} + \beta_4\, GROWTH_t + \beta_5\, SIZE_t + \beta_6\, LEV_t + \varepsilon_t} \qquad \textbf{(17)}$$

Where [denotes COMPUSTAT data element number]:

DACC = Signed value of discretionary accruals (residuals) from the four estimation models.

REQ = Dummy variable equal to one if the firm requested a rate increase in year t; zero otherwise.

CFO = Cash flow from operations scaled by lagged assets. [Data 308 / Data 6 lag1]

TAC_{t-1} = Lagged total accruals scaled by lagged assets. [(Data 18 – Data 308) / Data 6 lag1]

GROWTH = Sales growth. [(Data 12-Data 12 lag1) / Data 12 lag1]

SIZE = natural log of total assets. [logData 6]

LEV = Total debt divided by total assets. [(Data 9 + Data 34) / Data 6]

I predict *REQ's* coefficient to have a negative sign consistent with the argument that electric utilities depress earnings in those years they request rate increases. In the one-way fixed-effects model I include year dummies ($\sum \delta_t YDUM_t$) to control for specific year effects.

3.2.3.1 Additional Tests of Hypothesis 3: Models Incorporating Regulatory Assets (RA)

Attempts have been made to modify the Jones (1991) model to incorporate unique utility accounting. Paek (2001) adds allowed return on investment (AROE) to the Jones model arguing that allowed rate of return is one of the key economic factors in utilities operations. Loudder et al (1996) argue that there may be overstatement of regulatory assets in utility balance sheets due to discretion given to utilities in creating those assets. If utilities manage earnings in years they petition for rate increases, then I would expect them to use regulatory assets as one of the accounts for managing earnings. To test the proposition, I hand collect regulatory assets from Securities and Exchange Commission (SEC) form 10K filings for the period 1994-2005 using Lexis/Nexis and Edgar Plus to search the SEC data base. Before incorporating regulatory assets to model 17 above, I first test the significance of regulatory assets in the accrual specification models by estimating the following models cross-sectionally:

$$\mathbf{TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3 REGASSET_t + \varepsilon_t} \quad \textbf{(18)}$$

$$\mathbf{TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3 REGASSET_t + \varepsilon_t} \quad \textbf{(19)}$$

$$\mathbf{TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,REGASSET_t + \varepsilon_t} \quad \textbf{(20)}$$

$$\mathbf{TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3\,CFO_t + \beta_4\,REGASSET + \varepsilon_t} \quad \textbf{(21)}$$

Where: REGASSET are Regulatory Assets scaled by lagged assets. All the other variables are as defined above.

Finally, conditional on the variable REGASSET being significant in the estimation of models 18 through 21 above, I estimate the following model in testing whether electric utilities manage earnings through regulatory assets in the year they file for rate increases.

$$\mathbf{DACC_t = \alpha + \beta_1 REQ_t + \beta_2 CFO_t + \beta_3 TAC_{t-1} + \beta_4 GROWTH_t + \beta_5 SIZE_t + \beta_6 LEV_t + B_7\,REGASSET + \varepsilon_t} \qquad \textbf{(22)}$$

Where: $DACC_t$ represent Discretionary Accruals, residuals from estimating models 18 to 21 above. All variables are as previously defined.

4. EMPIRICAL RESULTS

4.1 Descriptive Statistics

Table 5 (Panel A) provides descriptive statistics for samples of rate-regulated electric utilities used in testing hypotheses one and two, and non-regulated manufacturing firms used in testing Hypothesis 1, i.e., sample one. The sample period for these observations is 1994-2005. Panel B depicts a separate sample (sample two) of utilities that requested a rate increase in at least one of the twelve sample years (1994-2005); these firms are used in testing Hypothesis 3.

Sample one's descriptive statistics show that, on average, control firms are significantly larger than utilities, and have significantly greater cash flows and sales growth. Median cash flows from operations of utilities are approximately 70 percent of their manufacturing counterparts. The median growth rate of control firms is 7 per cent, which is nearly twice that of electric utilities (4 percent). Panel A shows that electric utilities are more highly levered than the matched set of manufacturing firms by a factor of approximately 14 percent. These findings are consistent with Smith and Watts (1992) who find that regulated firms tend to be smaller, have lower growth rates and are more levered than non-regulated firms.

Sample two's descriptive statistics show that there is no significant difference in the values of control variables except for cash flows from operations (*CFO*). During the periods in which firms request for rate increases, the *CFO* has a depressed mean of 0.073 compared with a higher mean of 0.086 during the periods in which rate increases are not requested. The difference in mean cash flow's t-statistic is 2.45, statistically significant at $p<0.05$. This finding is logical because it is expected for utilities to petition for rate increases during those periods in which they face cash flow problems.

Table 5
Descriptive Statistics

Panel A: Descriptive Statistics for rate-regulated electric utilities and matched control firms (Sample one: n=188 for event period*)*

	Control Firms					Utilities					Test of differences		
Variables	**Mean**	**Median**	**Std**	**p25**	**p75**	**Mean**	**Median**	**Std**	**p25**	**p75**	**Δ Means**	**T-statistic**	**Wilcoxon Signed Rank Pr >= |S|**
SIZE	8.940	8.920	1.056	8.180	9.730	8.410	8.200	0.990	7.700	9.100	-0.530	5.08***	<0.0001
CFO	0.100	0.100	0.070	0.060	0.130	0.040	0.070	0.040	0.050	0.130	-0.060	4.9***	<0.0001
GROWTH	0.070	0.070	0.190	-0.001	0.130	0.000	0.040	0.210	-0.040	0.110	-0.070	3.63***	0.0003
LEV	0.280	0.260	0.180	0.170	0.380	0.350	0.350	0.090	0.290	0.390	0.070	-4.48***	<0.0001
TAC	-0.067	-0.050	0.080	-0.080	-0.032	-0.044	-0.043	0.039	-0.060	-0.024	0.023	-3.62***	<0.0001
LAG_TAC	-0.070	-0.060	0.070	-0.090	-0.039	-0.045	-0.045	0.040	-0.060	-0.028	0.025	-4.24***	<0.0001
DACC1	-0.059	-0.001	0.310	-0.050	0.032	-0.002	-0.002	0.050	-0.020	0.020	0.057	-3.43***	0.008
DACC2	-0.059	-0.001	0.310	-0.053	0.032	-0.004	-0.003	0.040	-0.024	0.016	0.055	-2.65***	0.2453
DACC3	-0.005	0.000	0.400	-0.051	0.033	0.003	0.003	0.044	-0.010	0.014	0.008	0.13	0.2830
DACC4	-0.006	-0.001	0.380	-0.054	0.040	0.003	0.002	0.043	-0.010	0.014	0.009	0.27	0.2200
AB_ACC1	0.100	0.042	0.190	0.019	0.095	0.030	0.020	0.035	0.010	0.040	-0.070	4.81***	<0.0001
AB_ACC2	0.113	0.040	0.300	0.020	0.077	0.030	0.020	0.030	0.010	0.040	-0.083	3.73***	<0.0001
AB_ACC3	0.145	0.040	0.390	0.010	0.090	0.020	0.010	0.040	0.006	0.030	-0.125	4.25***	<0.0001
AB_ACC4	0.144	0.045	0.350	0.016	0.110	0.030	0.010	0.040	0.005	0.022	-0.114	4.75***	<0.0001

Variable definitions:

SIZE	Log (assets)
CFO	Cash flow from operations scaled by lagged assets
GROWTH	Sales growth
LEV	Leverage (total debt/total assets)
TAC	Total accruals scaled by lagged assets
LAG_TAC	Lag total accruals scaled by lagged assets
DACC1	Discretionary accruals from the original Jones model (equation 1) (time series version)
DACC2	Discretionary accruals from the modified Jones model (equation 2) (time series version)
DACC3	Discretionary accruals from the original Jones model with control for extreme performance (equation 3) (time series version)
DACC4	Discretionary accruals from the modified Jones model with control for extreme performance (equation 4) (time series version)

AB_ACC1 - AB_ACC4 are absolute values of DACC1 - DACC4

Table 5 (Continued)
Descriptive Statistics

Panel B: Descriptive Statistics for electric utilities requesting and not requesting rate increases (Sample two)

	No rate increase request sample						Rate increase request sample						Tests of Differences		
Variables	**n**	**Mean**	**Median**	**Std**	**p25**	**p75**	**n**	**Mean**	**Median**	**Std**	**p25**	**p75**	**Δ Means**	**T-statistic**	**Wilcoxon Signed Rank Pr >= |S|**
SIZE	396	8.200	8.252	0.990	7.483	8.794	90	8.135	8.233	1.145	7.456	8.928	-0.065	0.58	0.78
CFO	396	0.086	0.086	0.030	0.068	0.104	90	0.073	0.081	0.048	0.060	0.097	-0.013	2.45**	0.03
GROWTH	396	0.110	0.036	0.800	-0.019	0.092	90	0.028	0.021	0.380	-0.085	0.111	-0.082	1.53	0.1019
LEV	396	0.350	0.347	0.080	0.310	0.377	90	0.342	0.342	0.060	0.310	0.392	-0.008	1.03	0.7990
TAC	396	-0.050	-0.049	0.030	-0.065	-0.035	90	-0.043	-0.048	0.040	-0.062	-0.031	0.007	-1.32	0.4677
LAG_TAC	396	-0.052	-0.047	0.070	-0.064	-0.032	90	-0.056	-0.050	0.080	-0.064	-0.027	-0.004	0.46	0.8469
DACC1	396	-0.001	-0.002	0.025	-0.016	0.015	90	0.001	0.000	0.029	-0.014	0.015	0.003	-0.83	0.3003
DACC2	396	-0.001	-0.002	0.025	-0.016	0.015	90	0.001	0.000	0.029	-0.014	0.015	0.003	-0.84	0.2970
DACC3	396	0.001	0.001	0.013	-0.007	0.008	90	-0.004	-0.004	0.015	-0.013	0.005	-0.005	2.68***	0.0089
DACC4	396	0.001	0.001	0.013	-0.006	0.008	90	-0.004	-0.005	0.015	-0.013	0.005	-0.005	2.88***	0.0085

Variables Definition:

SIZE	Log (assets)
CFO	Cash flow from operations scaled by lagged assets
GROWTH	Sales growth
LEV	Leverage (total debt/total assets)
TAC	Total accrual scaled by lagged assets
LAG_TAC	Lag total accrual scaled by lagged assets
DACC1	Discretionary (Abnormal) Accruals from the original Jones Model (Equation 1) (cross-sectional version).
DACC2	Discretionary (Abnormal) Accruals from the modified Jones Model (Equation 2) (cross-sectional version).
DACC3	Discretionary (Abnormal) Accruals from the original Jones Model with control for extreme performance (Equation 3) (cross-sectional version).
DACC4	Discretionary (Abnormal) Accruals from the modified Jones Model with control for extreme performance (Equation 4) (cross-sectional version).

Table 6 presents results of both Pearson's and Spearman's rank-order correlations for sample one. Correlation results reveal that earnings management metrics, absolute discretionary accruals estimated from all the four models (*AB_ACC1, AB_ACC2, AB_ACC3*, and *AB_ACC4*) are strongly correlated with each other and strongly negatively correlated with the rate-regulation variable (*RATE_REG*). In the Pearson correlation diagonal, the correlation coefficients between *RATE_REG* and *AB_ACC1, AB_ACC2, AB_ACC3* and *AB_ACC4* are: -0.24, -0.19, -0.21 and -0.24 respectively. Spearman's rank-order correlation shows the correlation coefficients between *RATE_REG* and *AB_ACC1, AB_ACC2, AB_ACC3* and *AB_ACC4* to be: -0.3, -0.31, -0.36 and -0.44 respectively. All of these correlation coefficients are statistically significant ($p<0.01$). These results provide strong evidence that rate regulation is strongly negatively correlated with absolute discretionary accruals. Although authoritative conclusions can not be drawn from correlation analysis, tentatively, I infer that rate regulation constrains earnings management. Regression analyses that conducted in later sections provide more valid results and inferences.

Pearson and Spearman correlations are in general agreement. Pearson (Spearman) shows that *CFO* is positively correlated with *SIZE* and *GROWTH* with correlation coefficients of 0.1110 (0.104), and 0.169 (0.267) respectively and is negatively correlated with *TAC* and *LAG_TAC* with coefficients -0.412 (-0.575) and -0.185 (-0.281). Both Pearson and Spearman show that *LEV* is positively correlated with *LAG_TAC*, and negatively correlated with *GROWTH* and *CFO*. All the aforementioned correlations are statistically significant at conventional levels.

These correlations are as expected, and suggest that multicollinearity does not affect inferences drawn from multiple regression analysis. As expected, diagnostic tests for multicollinearity (results not reported) find no evidence of multicollinearity among independent variables.

Table 6
Correlations of Selected Variables
Pearson (Upper Diagonal) / Spearman (Lower Diagonal)

	RATE_REG	AB_ACC1	AB_ACC2	AB_ACC3	AB_ACC4	TAC	LAG_TAC	SIZE	CFO	GROWTH	LEV
RATE_REG	1.0000	-0.2400	-0.1890	-0.2100	-0.2400	0.1860	0.2180	-0.2100	-0.2230	-0.1630	0.2010
		< 0.0001	0.0002	< 0.0001	< 0.0001	0.0003	< 0.0001	< 0.0001	< 0.0001	0.0014	< 0.0001
AB_ACC1	-0.3000	1.0000	0.9522	0.4281	0.9860	-0.1420	0.0200	-0.0300	-0.0120	-0.0900	0.2700
	< 0.0001		<0.0001	<0.0001	<0.0001	0.0060	0.6300	0.5700	0.8100	0.1000	< 0.0001
AB_ACC2	-0.3100	0.8842		0.3496	0.9437	-0.0800	0.0200	-0.0800	-0.0500	-0.1000	0.3400
	< 0.0001	<0.0001		<0.0001	<0.0001	0.1200	0.6700	0.1100	0.3400	0.0600	< 0.0001
AB_ACC3	-0.3600	0.4339	0.4151		0.4377	-0.0700	0.0600	0.1000	-0.0500	-0.0300	-0.0400
	< 0.0001	<0.0001	<0.0001		<0.0001	0.1700	0.2800	0.0500	0.3200	0.6200	0.4400
AB_ACC4	-0.4400	0.6941	0.6441	0.7407		-0.0800	0.0600	0.0800	-0.0560	-0.0400	0.0150
	< 0.0001	<0.0001	<0.0001	<0.0001		0.1400	0.2200	0.1000	0.2800	0.4400	0.7700
TAC	0.2000	-0.1600	-0.1860	-0.2100	-0.2400	1.0000	0.2700	0.0330	-0.4120	0.0070	0.0270
	< 0.0001	0.0020	0.0003	< 0.0001	< 0.0001		< 0.0001	0.5210	< 0.0001	0.8920	0.6000
LAG_TAC	0.2670	-0.1900	-0.2100	-0.1600	-0.1900	0.3740	1.0000	0.0730	-0.1850	-0.0320	0.1130
	< 0.0001	0.0003	< 0.0001	0.0020	0.0002	< 0.0001		0.1560	0.0003	0.5340	0.0300
SIZE	-0.2430	0.0500	0.0800	0.0700	0.0900	-0.0020	-0.0160	1.0000	0.1110	0.1340	-0.0140
	< 0.0001	0.2900	0.1300	0.1900	0.0800	0.9700	0.7600		0.0300	0.0090	0.7810
CFO	-0.2100	0.1000	0.1180	0.1200	0.1400	-0.5750	-0.2810	0.1040	1.0000	0.2670	-0.2950
	< 0.0001	0.0500	0.0200	0.0200	0.0060	< 0.0001	< 0.0001	0.0400		< 0.0001	< 0.0001
GROWTH	-0.1230	-0.0280	-0.0600	0.0800	0.0500	0.0630	-0.0180	0.0680	0.1690	1.0000	-0.1860
	0.0160	0.6000	0.2100	0.1100	0.2900	0.2180	0.7260	0.1850	0.0009		0.0003
LEV	0.2740	-0.1200	-0.1200	-0.1200	-0.1400	0.0590	0.1010	-0.0460	-0.3050	-0.1750	1.0000
	< 0.0001	0.0200	0.0200	0.0200	0.0600	0.2500	0.0480	0.3710	< 0.0001	0.0006	

Variable Definitions:

RATE_REG	An indicator variable equal to one for rate-regulated electric utilities and zero for control firms
AB_ACC1	Absolute DACC1
AB_ACC2	Absolute DACC2
AB_ACC3	Absolute DACC3
AB_ACC4	Absolute DACC4
TAC	Total accruals scaled by lagged assets
LAG_TAC	Lag total accrual scaled by lagged assets
SIZE	Log (assets)
CFO	Cash flow from operations scaled by lagged assets
GROWTH	Sales growth
LEV	Leverage (total debt/total assets)

4.2 Hypothesis 1 Results

4.2.1 Results of Time Series Tests

Table 5 (Panel A) presents results of mean discretionary accruals estimated from all the four time series models (Models 1 - 4) for both utilities and control firms. For electric utilities, these values are not significantly different from zero which suggests that, on average, electric utilities do not manage earnings using discretionary accruals. Table 5 (Panel A) also reports t-test and Wilcoxon rank sum results for differences in means and medians respectively of earnings management metrics between utility firms and control firms. Because Hypothesis 1 is non-directional, the absolute value of discretionary accruals is the variable of interest. Differences in the means of absolute discretionary accruals (*AB_ACC*) between regulated electric utilities and the control firms estimated from models are significant ($p<0.01$) for each of the four discretionary accrual models. Together with the mean values of the discretionary accruals provided in the table, this difference test indicates that the discretionary accruals of rate-regulated electric utilities are significantly smaller than those of matched manufacturing firms. Therefore, Hypothesis 1 is rejected. This result is consistent with regulatory scrutiny, on average, reducing opportunities for earnings management by utilities. This might be viewed as an unanticipated benefit provided by rate regulation, suggesting that, on average, rate regulation provides sufficient monitoring to preclude earnings management as measured by discretionary accruals.

4.2.2 Results of Cross-Sectional Tests

Table 7 reports the results of cross-sectional estimations of models 5 - 8 in Panels A through D respectively. The models follow Cahan's (1992) specification, regressing total accruals on the Jones (and modified Jones) model's determinants. The indicator variable

RATE_REG is introduced to test Hypothesis 1. The logic here is that the model's error term captures discretionary accruals, and if the introduced indicator variable is omitted from the model, its effect will be captured by the error term. Therefore, if the indicator variable is statistically significant, then discretionary accruals are related to the indicator variable. I report the results for cross-sectional annual regressions for each model, as well as the results for the one-way fixed effects model using pooled observations. Following Fama and MacBeth (1973), I also use the means of the 12 annual cross-sectional coefficients and the time series standard error to provide cumulative results of the year-by-year regressions for variable of interest, *RATE_REG*.

The annual regressions have R-Squares ranging from 0.90 to 0.35. Higher values tend to appear earlier in the sample period, and 2005 stands out with its low values. This trend in R-Squares might be indicative of a change in the operating environment for rate-regulated utilities over time, i.e. deregulation effects that are examined in testing Hypothesis 2. *ΔSALES* is not significant in models 5 and 6, and becomes significantly negative with the addition of *CFO* in models 7 and 8. All other variables are directionally significant as expected. The coefficient of *RATE_REG* is significantly negative at standard levels for at least six of the twelve annual regressions depicted for each model (Panels A – D). Out of the 12 annual regressions, the test variable, *RATE_REG* is negative and significant in 9, 10, 6, and 6 years for regression models 5, 6, 7, and 8 respectively.

In the one-way fixed effects models with pooled observations, the test variable, *RATE_REG* has the following coefficient estimate (T-statistic): -0.0306 (-10.15), -0.0306 (-10.15), -0.0196 (-6.35), and -0.0195 (-6.32) for model 5, model 6, model 7, and model 8 estimations respectively. Each model's T-statistic is significant at $p<0.01$. The results present strong evidence that after pooling observations and controlling for fixed time effects (year dummies), the test variable, *RATE_REG* is significant and negatively related to earnings management metric. These results are consistent across all the four models.

In order to provide additional support to the one-way fixed effects model estimation results, I perform Fama and MacBeth cross-sectional regressions of total absolute accruals on the test variable, *RATE_REG* and Jones and modified Jones model variables. The results presented in table 7 (Panels A-D) indicate the following mean coefficient estimates (t-statistics) for the test variable, *RATE_REG*; -0.028 (-5.98), -0.028 (5.64), -0.014 (-2.65), and -0.014 (-2.54) for model 5, model 6, model 7, and model 8 estimations respectively. Each model's t-statistic is significant at $p<0.05$ or better. Fama and MacBeth procedure results corroborate those of annual cross-sectional estimations and one-way fixed effects analysis that the test variable, *RATE_REG* has a significantly negative coefficient. These regression results provide evidence and support correlation analysis results that the absolute values of total accruals are negatively associated with the rate-regulation variable. Furthermore, cross-sectional test results are consistent with time series results that electric utilities' discretionary accruals are significantly less than those of their manufacturing counterparts (control sample).

Therefore, Hypothesis 1, stated in the null form that no differences exist between absolute discretionary accruals of rate-regulated electric utilities and non-regulated firms (control sample), is rejected. Because absolute discretionary accrual is used as an earnings management metric in this study, the interpretation of these results is that there is a lower magnitude of earnings management in rate-regulated electric utilities than in comparable non-regulated companies. This finding suggests that rate regulation constraints earnings management and should be an interesting finding to electric utility regulators.

Table 7
Tests of Hypothesis 1: Results of Cross-Sectional Estimation of Discretionary Accruals with an Indicator Variable of Rate Regulation

Coefficient (T-statistic)

Panel A: Model 5: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1\Delta SALES_t + \beta_2 PPE_t + \beta_3 RATE\_REG_t + \varepsilon_t$

One-way Fixed Effects: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1\Delta SALES_t + \beta_2 PPE_t + \beta_3 RATE\_REG_t + \sum\alpha YDUM_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	Adj.R^2
1994	86	8.089	0.125	0.0356	-0.001	0.81
		(1.60)	(4.25***)	(6.00***)	(-0.14)	
1995	88	-0.963	0.1354	0.0346	0.003	0.81
		(-0.15)	(5.89***)	(5.52***)	(0.39)	
1996	89	-13.528	0.0882	0.0669	-0.0287	0.76
		(-1.56)	(3.85***)	(10.19***)	(-3.83***)	
1997	89	19.488	-0.04	0.065	-0.0324	0.60
		(1.28)	(-1.42)	(6.40***)	(-2.78***)	
1998	93	59.867	0.031	0.058	-0.0444	0.68
		(4.08***)	(1.07)	(6.34***)	(-4.21***)	
1999	93	8.68	0.0488	0.0614	-0.0316	0.62
		(0.59)	(2.57**)	(7.03***)	(-3.19***)	
2000	93	(15.059)	(0.0188)	(0.0462)	(-0.0167)	0.62
		(1.07)	(1.82*)	(6.63***)	(-2.02**)	
2001	94	6.15	-0.0184	0.081	-0.0355	0.55
		(0.26)	(-0.76)	(7.49***)	(-2.84)	
2002	94	21.472	-0.0399	0.0815	-0.0417	0.47
		(0.73)	(-2.12**)	(5.72***)	(-2.34**)	
2003	94	12.965	-0.015	0.0707	-0.0346	0.56
		(0.66)	(-0.39)	(6.80***)	(-2.88***)	
2004	94	0.27	0.0073	0.063	-0.0224	0.65
		(0.02)	(0.36)	(7.43***)	(-2.50***)	
2005	94	20.931	0.0389	0.0747	-0.0489	0.35
		(0.68)	(0.85)	(4.28***)	(-2.71***)	
Fixed effects	1101	10.5823	0.0009	0.0167	-0.0306	0.64
		(2.66***)	(0.15)	(3.85***)	(-10.15***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, RATE_REG is different from zero

Variable	Coefficient Mean	T-statistic
RATE_REG	-0.028	-5.98***

***, **, * Denote significant at 0.01, 0.05, and 0.1 respectively (two-tailed test)

│TAC│ = Absolute total accruals scaled by lagged assets
TA = Total assets
ΔSALES = Change in total sales scaled by lagged assets
PPE = Plant, Property and Equipment scaled by lagged assets
RATE_REG = An indicator variable that equals one for rate-regulated electric utilities and zero for matched control firms
YDUM = Year dummy

Table 7 (Continued)
Tests of Hypothesis 1: Results of Cross-Sectional Estimation of Discretionary Accruals with an Indicator Variable of Rate Regulation

Coefficient (T-statistic)

Panel B: Model 6: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1(\Delta Sales_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3 RATE\_REG_t + \varepsilon_t$

One-way fixed effects: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1(\Delta Sales_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3 RATE\_REG_t + \sum \alpha YDUM_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	Adj.R^2
1994	86	7.0997	0.1707	0.0348	0.0000	0.83
		(1.46)	(5.03***)	(6.23***)	(0.999)	
1995	88	0.9837	0.155	0.0324	0.0054	0.80
		(0.15)	(5.44***)	(4.81***)	(0.66)	
1996	89	-9.894	0.106	0.0659	-0.0288	0.77
		(-1.15)	(4.26***)	(10.16***)	(-3.92***)	
1997	89	19.811	-0.0422	0.0647	-0.0323	0.60
		(1.30)	(-1.35)	(6.37***)	(-2.77***)	
1998	93	60.017	0.0369	0.0581	-0.0446	0.68
		(4.10***)	(1.18)	(6.36***)	(-4.23***)	
1999	93	9.038	0.05	0.0621	-0.0322	0.62
		(0.61)	(2.50***)	(7.12***)	(-3.24***)	
2000	93	14.889	0.0215	0.0463	-0.0163	0.62
		(1.06)	(1.87*)	(6.67***)	(-1.97**)	
2001	94	7.3049	-0.0086	0.0809	-0.0365	0.55
		(0.31)	(-0.34)	(7.45***)	(-2.89***)	
2002	94	21.176	-0.0398	0.0812	-0.0412	0.47
		(0.72)	(-2.06**)	(5.69***)	(-2.31**)	
2003	94	13.9238	0.0005	0.0689	-0.0333	0.56
		(0.71)	(0.01)	(6.79***)	(-2.81***)	
2004	94	0.73	0.0129	0.062	-0.0216	0.65
		(0.05)	(0.59)	(7.34***)	(-2.42***)	
2005	94	20.277	0.0243	0.0775	-0.0505	0.35
		(0.66)	(0..50)	(4.47***)	(-2.80***)	
Fixed effects	1101	10.5823	0.0009	0.0167	-0.0306	0.64
		(2.66***)	(0.15)	(3.85***)	(-10.15***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, RATE_REG is different from zero

Variable	Coefficient Mean	T-statistic
RATE_REG	-0.028	-5.64***

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (two-tailed test)

|TAC| = Absolute total accruals scaled by lagged assets
TA = Total assets
ΔSALES = Change in total sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, Property and Equipment scaled by lagged assets
RATE_REG = An indicator variable that equals one for rate-regulated electric utilities and zero for matched control firms
YDUM = Year dummy

Table 7 (Continued)
Tests of Hypothesis 1: Results of Cross-Sectional Estimation of Discretionary Accruals with an Indicator Variable of Rate Regulation

Coefficient (T-statistic)

Panel C: Model 7: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1\Delta SALES_t + \beta_2 PPE_t + \beta_3 CFO_t + \beta_4 RATE\_REG_t + \varepsilon_t$

One-way fixed effects: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1\Delta SALES_t + \beta_2 PPE_t + \beta_3 CFO_t + \beta_4 RATE\_REG_t + \sum\alpha YDUM_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	Adj. R^2
1994	86	2.096	0.04	0.0135	0.2822	0.005	0.90
		(0.54)	(1.69*)	(2.58**)	(8.07***)	(0.014)	
1995	88	-3.3271	0.0931	0.0103	0.2226	0.0144	0.84
		(-0.57)	(4.03***)	(1.29)	(4.31***)	(1.95*)	
1996	89	-10.286	0.0228	0.0349	0.263	-0.0132	0.83
		(-1.39)	(1.01)	(4.41***)	(5.71***)	(-1.90*)	
1997	89	16.1584	-0.0551	0.0055	0.472	0.0000	0.82
		(1.60)	(-2.90***)	(0.62)	(10.44***)	(0.992)	
1998	93	58.2017	-0.0022	0.0306	0.256	-0.0317	0.71
		(4.20***)	(-0.08)	(2.62***)	(3.47***)	(-2.99***)	
1999	93	-4.2187	0.0221	0.0189	0.3689	-0.0029	0.77
		(-0.36)	(1.41)	(2.07**)	(7.16***)	(-0.33)	
2000	93	-2.316	0.0024	0.0224	0.2379	0.0013	0.73
		(-0.19)	(0.27)	(3.20***)	(6.20***)	(0.18)	
2001	94	5.1233	-0.0214	0.0667	0.1408	-0.0305	0.56
		(0.22)	(-0.88)	(4.78***)	(1.61)	(-2.38**)	
2002	94	23.7224	-0.047	0.0549	0.3049	-0.0418	0.50
		(0.83)	(-2.53**)	(3.07***)	(2.36**)	(-2.41**)	
2003	94	14.3374	-0.0297	0.0304	0.4345	-0.023	0.65
		(0.82)	(-0.87)	(2.49**)	(5.04***)	(-2.11**)	
2004	94	3.9392	-0.0316	0.0245	0.3807	-0.0094	0.78
		(0.33)	(-1.81*)	(2.82***)	(7.06***)	(-1.26)	
2005	94	16.1044	-0.0089	0.0495	0.2876	-0.0362	0.39
		(0.54)	(-0.18)	(2.49**)	(2.42**)	(-1.97**)	
Fixed effects	1101	7.5798	-0.0117	0.0105	0.2235	-0.0196	0.67
		(1.99**)	(-2.01**)	(2.50**)	(10.16***)	(-6.35***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, RATE_REG is different from zero

Variable	Coefficient Mean	T-statistic
RATE_REG	-0.014	-2.65**

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (two-tailed test)

|TAC| = Absolute total accruals scaled by lagged assets
TA = Total assets
ΔSALES = Change in sales scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
RATE_REG = An indicator variable that equals one for rate-regulated electric utilities and zero for matched control firms
YDUM = Year dummy

Table 7 (Continued)
Tests of Hypothesis 1: Results of Cross-Sectional Estimation of Discretionary Accruals with an Indicator Variable of Rate Regulation

Coefficient (T-statistic)

Panel D: Model 8: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3 CFO_t + \beta_4 RATE\_REG_t + \varepsilon_t$

One-way fixed effects: $|TAC_t| = \alpha(1/TA_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2 PPE_t + \beta_3 CFO_t + \beta_4 RATE\_REG_t + \sum \alpha YDUM_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	Adj.R^2
1994	86	1.2943	0.076	0.013	0.269	0.0069	0.90
		(0.34)	(2.68***)	(2.57**)	(7.90***)	(1.28)	
1995	88	-1.957	0.1017	0.0083	0.2313	0.016	0.84
		(-0.33)	(3.57***)	(1.02)	(4.40***)	(2.05**)	
1996	89	-9.1877	0.0336	0.0355	0.2539	-0.0137	0.83
		(-1.24)	(1.33)	(4.50***)	(5.46***)	(-1.97**)	
1997	89	16.6016	-0.055	0.0052	0.4695	-0.0003	0.82
		(1.63)	(-2.65***)	(0.59)	(10.32***)	(-0.03)	
1998	93	58.101	0.0015	0.031	0.253	-0.0319	0.72
		(4.20***)	(0.05)	(2.64***)	(3.42***)	(-3.01***)	
1999	93	-4.1705	0.0237	0.0191	0.3697	-0.0031	0.76
		(-0.35)	(1.44)	(2.09**)	(7.21***)	(-0.35)	
2000	93	-2.3249	0.0026	0.0224	0.2379	0.0014	0.85
		(-0.19)	(0.26)	(3.20***)	(6.18***)	(0.18)	
2001	94	6.1949	-0.0127	0.0667	0.1396	-0.0314	0.55
		(0.27)	(-0.51)	(4.76***)	(1.59)	(-2.42**)	
2002	94	23.23	-0.0462	0.055	0.298	-0.0412	0.50
		(0.81)	(-2.42**)	(3.07***)	(2.30**)	(-2.36**)	
2003	94	15.0838	-0.0193	0.029	0.4335	-0.0217	0.65
		(0.86)	(-0.55)	(2.40**)	(5.00***)	(-2.02**)	
2004	94	4.048	-0.029	0.0241	0.3773	-0.009	0.77
		(0.34)	(-1.56)	(2.75***)	(6.95***)	(-1.19)	
2005	94	14.2158	-0.0311	0.0502	0.3087	-0.0369	0.39
		(0.47)	(-0.60)	(2.53**)	(2.59**)	(-2.02**)	
Fixed effects	1101	7.4737	-0.0117	0.0105	0.223	-0.0195	0.67
		(1.96**)	(-1.89*)	(2.49**)	(10.13***)	(-6.32***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, RATE_REG is different from zero

Variable	Coefficient Mean	T-statistic
RATE_REG	-0.014	-2.54**

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (two-tailed test)

|TAC| = Absolute total accruals scaled by lagged assets
TA = Total assets
ΔSALES = Change in sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
RATE_REG = An indicator variable that equals one for rate-regulated electric utilities and zero for matched control firms
YDUM = Year dummy

4.3 Hypothesis 2 Results

Hypothesis 2 examines if the deregulation of the generating and marketing functions that occurred in certain states in the late 1990s and early 2000s affected the earnings management metric. Table 8 reports results of regression tests for H_{2A} and Table 9 presents results for H_{2B}.

Table 8 includes only utilities from those states that undertook some deregulatory action within the sample period. It reveals that the variables representing Δ*SALES* and *(*Δ*SALES* - Δ*REC*) are not significant in all models and the *PPE* variable is only significant in models 1 and 2. *CFO* is significantly positive in models 3 and 4. The variable of interest, *POST*, parses the sample with respect to time and compares the pre-deregulation period (1994-1999) and post-deregulation period. *POST* is significantly positive ($p<0.01$) in each of the four model regressions. This suggests that the discretionary accruals for utilities in deregulating states were significantly greater after year 2000, consistent with Hypothesis 2.

Table 9 includes all of sample two's utilities for the post-deregulation period only (2000-2005). It reveals that the variables representing Δ*SALES* and *(*Δ*SALES* - Δ*REC*) are significantly negative in all models and the *PPE* variable is only significant in models 1 and 2. *CFO* is again significantly positive in models 3 and 4. The variable of interest, *DEREG*, parses utilities into those operating in states that have implemented some form of retail deregulation, and those in states that have not implemented deregulation. *DEREG* is significantly positive ($p<0.05$) in models 1 and 2. This indicates that after the year 2000, the discretionary accruals for utilities in deregulating states were significantly greater than those of utilities in states that did not deregulate. However, *DEREG* is statistically insignificant in models 3 and 4. Therefore, given these mixed results regarding the difference in discretionary accruals between utilities in deregulated and rate-regulated jurisdictions, Table 9 provides some evidence that that this change in utilities' operating environment was associated with deregulation.

Table 8
Electric Utilities in Those States that Have Implemented Retail Deregulation: Contrasting Discretionary Accruals Between Pre- and Post-Deregulation Periods
Coefficient (T-statistic)

Regression Models Testing Hypothesis 2_A:

Model 1: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3 POST_t + \sum \alpha_j YDUM_t + \varepsilon_t$

Model 2: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,POST_t + \sum \alpha_j YDUM_t + \varepsilon_t$

Model 3: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,POST_t + \sum \alpha_j YDUM_t + \varepsilon_t$

Model 4: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,POST_t + \sum \alpha_j YDUM_t + \varepsilon_t$

Variable	Model 1	Model 2	Model 3	Model 4
$1/TA_{t-1}$	11.2049	11.1878	5.661	5.6428
	(2.25**)	(2.24**)	(1.34*)	(1.33*)
ΔSALES	0.0114		0.0078	
	(0.82)		(0.67)	
PPE	0.0141	0.0142	-0.0004	-0.0004
	(3.22***)	(3.24***)	(-0.10)	(-0.09)
(ΔSales - ΔREC)		0.0119		0.0053
		(0.85)		(0.45)
CFO			0.3865	0.3863
			(10.95***)	(10.93***)
POST	0.0239	0.029	0.0152	0.0153
	(3.81***)	(3.81***)	(2.84***)	(2.86***)
R^2	0.82	0.82	0.87	0.87
n	308	308	308	308

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
|TAC| = Absolute total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
POST = An indicator variable that equals one for post-deregulation and zero for pre-deregulation periods
YDUM = Year dummy

Table 9
Electric Utilities in the Post-Deregulation Period:
Contrasting Discretionary Accruals Between Utilities Located in States Implementing Retail Deregulation and Utilities in States Not Implementing Retail Deregulation
Coefficient (T-statistic)

Regression Models Testing Hypothesis 2_B:

Model 1: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3 DEREG_t + \sum\alpha_j YDUM_t + \varepsilon_t$
Model 2: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\,\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,DEREG_t + \sum\alpha_j YDUM_t + \varepsilon_t$
Model 3: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,DEREG_t + \sum\alpha_j YDUM_t + \varepsilon_t$
Model 4: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,DEREG_t + \sum\alpha_j YDUM_t + \varepsilon_t$

Variable	Model 1	Model 2	Model 3	Model 4
$1/TA_{t-1}$	9.5476	9.478	1.7025	1.5726
	(1.58*)	(1.57*)	(0.32)	(0.30)
ΔSales	-0.0149		-0.0223	
	(-2.39***)		(-4.15***)	
PPE	0.0283	0.0281	0.0036	0.0032
	(7.74***)	(7.73***)	(0.89)	(0.81)
(ΔSales - ΔREC)		-0.0168		-0.0245
		(-2.55***)		(-4.28***)
CFO			0.4811	0.4808
			(9.97***)	(9.99***)
DEREG	0.0062	0.0063	0.0018	0.0018
	(1.83**)	(1.84**)	(0.60)	(0.61)
R^2	0.71	0.71	0.79	0.79
n	282	282	282	282

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
|TAC| = Absolute total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
DEREG = An indicator variable that equals one if a utility operates in a state that has passed deregulation legislation and zero otherwise
YDUM = Year dummy

4.4 Hypothesis 3 Results

Table 5 (Panel B) presents descriptive statistics of variables used to test Hypothesis 3. Descriptive statistics reveal that the only significant difference between these two samples relates to cash flows. This should not be surprising because the same firms appear in both categories: those requesting a rate increase that year, and those not requesting a rate increase that year. I am therefore trying to capture only those determinants that change significantly between years. For those years in which utilities request rate increases, they experience a mean cash flow from operations (*CFO*) of 0.07 while for those years in which firms do not make a rate request have a mean of 0.09. The difference in means is statistically significant ($p<0.05$). Reduced cash flows as depicted by the above statistics may be a driving force for utilities to manage earnings in an attempt to convince regulators to increase rates.

Differences in means of the cross-sectional earnings management metrics (*DACC1 – DACC4*), estimated using models 1, 2, 3, and 4 between the two groups of firm-years appear in Table 5 (Panel B). Results provide evidence that signed discretionary accruals estimated from models 3 and 4 are significantly more positive ($p<0.01$) for firm-years in which no rate request is made when compared to firm-years in which a utility requests a rate increase. This result is consistent with Hypothesis 3. However, there is no significant difference between the discretionary accruals generated for these two groups by models 1 and 2. Therefore, the univariate results are mixed.

The results of the multivariate tests of Hypothesis 3 are reported in Table 10 and in Table 11, I report the results of Fama and MacBeth cross-sectional regressions in Table 10. In Table 11, I report results of annual cross-sectional regressions along with those of pooled estimation using a one-way fixed effects model.

Table 10
Tests of Hypothesis 3: Results of Fama and MacBeth Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables
Coefficient (T-statistic[34])

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.083	0.083	0.02	0.02
		(6.84***)	(6.67***)	(3.24***)	(3.23***)
Test variable					
REQ	-	-0.006	-0.005	-0.007	-0.007
		(-2.41**)	(-2.27**)	(-4.28***)	(-4.54***)
Controls					
SIZE	-	-0.006	-0.002	0.0002	0.0002
		(-2.26**)	(-2.16**)	(0.40)	(0.45)
CFO	-	-0.612	-0.61	-0.061	-0.063
		(-12.01***)	(-12.00***)	(-2.34**)	(-2.38**)
LG_TAC	+	-0.018	-0.033	0.0146	0.0156
		(-0.28)	(-0.49)	(0.35)	(0.37)
GROWTH	+	0.0117	0.0138	-0.003	-0.00086
		(1.26)	(1.43*)	(-1.20)	(-0.33)
LEV	+	-0.053	-0.055	-0.043	-0.043
		(-2.93***)	(-2.99***)	(-3.15***)	(-3.18***)
n		468	465	471	471
R^2		0.53	0.54	0.18	0.17

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

[34] T-statistic computation follows Fama and MacBeth procedure of dividing the average of annual coefficient estimates by the time series standard error. T-statistic $= \dfrac{meanest}{stdest/\sqrt{n-1}}$ Where: meanest = Average of annual coefficient estimates; stdest = standard deviation of estimates and n = number of years.

Table 11
Tests of Hypothesis 3: Results of Annual Cross-Sectional and Fixed Effects Regressions of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables

Coefficient (P-value)

Panel A

Model: $DACC1_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1994	38	0.1394	-0.0149	-0.0039	-0.8436	-0.0025	0.0644	-0.1104	0.73
		(<0.0001***)	(0.006***)	(0.07*)	(<0.0001***)	(0.40)	(0.03**)	(<0.0001***)	
1995	39	0.1269	0.0102	-0.0034	-0.6289	0.1889	0.0139	-0.0994	0.75
		(<0.0001***)	(0.02**)	(0.04**)	(<0.0001***)	(0.02**)	(0.13)	(<0.0001***)	
1996	38	0.0266	-0.0066	-0.0026	-0.4526	-0.1058	-0.0273	0.0983	0.52
		(0.17)	(0.09*)	(0.08*)	(0.0002***)	(0.16)	(0.03**)	(0.03**)	
1997	39	0.1204	-0.0127	-0.0040	-0.3081	0.4212	0.0050	-0.1130	0.35
		(0.0009***)	(0.1*)	(0.09*)	(0.02***)	(0.03**)	(0.20)	(0.03**)	
1998	39	0.0476	-0.0081	0.0016	-0.5088	0.0640	-0.0004	-0.0259	0.62
		(0.04**)	(0.18)	(0.26)	(<0.0001***)	(0.32)	(0.48)	(0.27)	
1999	43	0.1128	-0.0127	-0.0054	-0.7890	-0.1923	-0.0136	-0.0411	0.76
		(0.0001***)	(0.03**)	(0.01***)	(<0.0001***)	(0.03**)	(0.03**)	(0.14)	
2000	39	0.0206	-0.0128	0.0012	-0.4728	-0.3123	-0.0045	-0.0085	0.37
		(0.32)	(0.1*)	(0.38)	(0.001***)	(0.006***)	(0.35)	(0.43)	
2001	44	0.0638	0.0021	0.0013	-0.7756	-0.2333	-0.0202	-0.0689	0.8
		(0.04**)	(0.39)	(0.35)	(<0.0001***)	(0.07*)	(0.0005***)	(0.08*)	
2002	44	0.0943	-0.0013	-0.0005	-0.7699	-0.1565	0.0207	-0.0598	0.61
		(0.006***)	(0.44)	(0.44)	(<0.0001***)	(0.02**)	(0.07*)	(0.08*)	
2003	53	0.0779	-0.0016	-0.0003	-0.6098	0.0720	0.0266	-0.0744	0.5
		(0.008***)	(0.40)	(0.46)	(<0.0001***)	(0.1*)	(0.09*)	(0.06*)	
2004	52	0.0842	-0.0034	-0.0021	-0.5783	0.0574	0.0640	-0.0827	0.56
		(0.0002***)	(0.29)	(0.15)	(<0.0001***)	(0.24)	(0.02**)	(0.01***)	
Fixed effects	468	0.0790	-0.0022	-0.0019	-0.6114	-0.0085	-0.0028	-0.0683	0.53
		(<0.0001***)	(0.15)	(0.01***)	(<0.0001***)	(0.22)	(0.15)	(<0.0001***)	

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)

DACC1 = Signed discretionary accrual, residual from the following estimation:

$TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta SALES_t + \beta_2\ PPE_t + \varepsilon_t$ [Jones Model]

REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise

SIZE = Natural log of total assets

CFO = Cash flow from operations scaled by lagged assets

LG_TAC = Lagged total accruals scaled by lagged assets

GROWTH = Sales growth.

LEV =Leverage defined as total debt divided by total assets

Table 11 (Continued)
Tests of Hypothesis 3: Results of Annual Cross-Sectional and Fixed Effects Regressions of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables

Coefficient (P-value)

Panel B

Model: $DACC2_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β₁	B₂	β₃	β₄	β₅	β₆	R^2
1994	38	0.1397	-0.0147	-0.004	-0.8419	-0.0021	0.0796	-0.1099	0.73
		(<0.0001***)	(0.007***)	(0.07*)	(<0.0001***)	(0.42)	(0.01***)	(0.0001***)	
1995	39	0.1284	0.0096	-0.0036	-0.6333	0.1853	0.019	-0.1001	0.76
		(<0.0001***)	(0.02**)	(0.03**)	(<0.0001***)	(0.02**)	(0.06*)	(<0.0001***)	
1996	38	0.0265	-0.0065	-0.0026	-0.4514	-0.1051	-0.0260	0.0981	0.52
		(0.17)	(0.1*)	(0.08*)	(0.0002***)	(0.16)	(0.04**)	(0.03**)	
1997	39	0.1204	-0.0126	-0.0040	-0.3100	0.4195	0.0050	-0.1124	0.35
		(0.0009***)	(0.1*)	(0.09*)	(0.02***)	(0.03**)	(0.20)	(0.03**)	
1998	39	0.0486	-0.0085	0.0015	-0.5093	0.0634	-0.0011	-0.0269	0.62
		(0.04**)	(0.17)	(0.27)	(<0.0001***)	(0.32)	(0.45)	(0.27)	
1999	43	0.1111	-0.0119	-0.0052	-0.7845	-0.1933	-0.0100	-0.0419	0.77
		(0.0001***)	(0.04**)	(0.01***)	(<0.0001***)	(0.03**)	(0.08*)	(0.13)	
2000	39	0.0206	-0.0128	0.0012	-0.4727	-0.3129	-0.0046	-0.0087	0.37
		(0.32)	(0.1*)	(0.38)	(0.001***)	(0.006***)	(0.35)	(0.43)	
2001	43	0.0509	0.0039	0.0024	-0.7636	-0.3494	-0.0193	-0.0799	0.82
		(0.07*)	(0.29)	(0.23)	(<0.0001***)	(0.01***)	(0.0003***)	(0.04**)	
2002	44	0.0945	-0.0025	-0.0005	-0.7730	-0.1613	0.0223	-0.0591	0.6
		(0.006***)	(0.39)	(0.44)	(<0.0001***)	(0.02**)	(0.06*)	(0.08*)	
2003	52	0.0777	-0.0021	-0.0002	-0.6270	0.0352	0.0352	-0.0775	0.51
		(0.007***)	(0.32)	(0.47)	(<0.0001***)	(0.3200)	(0.05**)	(0.05**)	
2004	51	0.0980	-0.0004	-0.0040	-0.5414	0.0552	0.0512	-0.0840	0.59
		(<0.0001***)	(0.47)	(0.03**)	(<0.0001***)	(0.23)	(0.04**)	(0.006***)	
Fixed effects	465	0.0829	-0.0021	-0.0022	-0.6162	-0.0148	-0.0019	-0.0693	0.54
		(<0.0001***)	(0.15)	(0.004***)	(<0.0001***)	(0.08*)	(0.24)	(<0.0001***)	

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC2 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 11 (Continued)
Tests of Hypothesis 3: Results of Annual Cross-Sectional and Fixed Effects Regressions of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables
Coefficient (P-value)

Panel C:
Model: $DACC3_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1994	38	0.0492	-0.0069	-0.001	-0.0824	-0.0024	0.0007	-0.0939	0.51
		(0.004***)	(0.04**)	(0.29)	(0.1*)	(0.37)	(0.49)	(<0.0001***)	
1995	39	0.0385	0.0063	-0.0003	-0.0134	0.0876	0.0073	-0.0931	0.72
		(0.003***)	(0.02**)	(0.4)	(0.40)	(0.05**)	(0.16)	(<0.0001***)	
1996	38	-0.0047	-0.0087	-0.0008	-0.1173	-0.0856	-0.0177	0.0592	0.26
		(0.46)	(0.02**)	(0.28)	(0.09*)	(0.15)	(0.06*)	(0.07*)	
1997	38	0.0307	-0.0103	-0.0004	0.0956	0.2786	-0.0008	-0.0571	0.24
		(0.07*)	(0.04**)	(0.40)	(0.12)	(0.01***)	(0.40)	(0.04**)	
1998	39	0.0089	-0.0123	0.0001	0.0298	0.0513	0.0031	-0.0254	0.17
		(0.29)	(0.01***)	(0.47)	(0.27)	(0.26)	(0.28)	(0.16)	
1999	43	-0.0008	-0.0118	0.0001	-0.0194	-0.0747	0.0059	-0.0063	0.32
		(0.48)	(0.003***)	(0.48)	(0.34)	(0.1*)	(0.08*)	(0.39)	
2000	38	-0.0108	-0.0113	0.0039	-0.2253	-0.2571	0.0003	-0.0365	0.37
		(0.38)	(0.1*)	(0.1*)	(0.03**)	(0.006***)	(0.49)	(0.19)	
2001	48	0.0299	-0.0040	-0.0012	-0.0984	0.0380	-0.0040	-0.0273	0.26
		(0.07*)	(0.18)	(0.25)	(0.001***)	(0.30)	(0.1*)	(0.1*)	
2002	44	0.0073	-0.0027	0.0028	-0.1316	-0.0633	-0.0176	-0.0529	0.33
		(0.38)	(0.33)	(0.12)	(0.06*)	(0.1*)	(0.04**)	(0.04**)	
2003	54	0.0340	-0.0075	-0.0010	-0.0255	0.1082	-0.0156	-0.0458	0.25
		(0.05**)	(0.03**)	(0.29)	(0.33)	(0.003***)	(0.1*)	(0.07*)	
2004	52	0.0382	-0.0070	0.0001	-0.0878	0.0797	0.0014	-0.0973	0.25
		(0.02**)	(0.04**)	(0.48)	(0.09*)	(0.1*)	(0.48)	(0.0005***)	
Fixed effects	471	0.0208	-0.0052	0.0002	-0.0804	-0.0024	0.0023	-0.0600	0.18
		(0.0003***)	(0.0002***)	(0.38)	(<0.0001***)	(0.37)	(0.1*)	(<0.0001***)	

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC3 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 11 (Continued)
Tests of Hypothesis 3: Results of Annual Cross-Sectional and Fixed Effects Regressions of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables
Coefficient (P-value)

Panel D:
Model: $DACC4_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1994	38	0.0488	-0.0068	-0.0009	-0.085	-0.0022	-0.0001	-0.0938	0.51
		(0.004***)	(0.05**)	(0.3)	(0.1*)	(0.38)	(0.49)	(<0.0001***)	
1995	39	0.0394	0.0061	-0.0004	-0.0172	0.0867	0.0089	-0.0934	0.72
		(0.002***)	(0.02**)	(0.38)	(0.38)	(0.05**)	(0.1*)	(<0.0001***)	
1996	38	-0.0051	-0.0087	-0.0008	-0.1181	-0.0869	-0.0152	0.0589	0.26
		(0.41)	(0.02**)	(0.29)	(0.09*)	(0.14)	(0.09*)	(0.07*)	
1997	38	0.0306	-0.0104	-0.0004	0.0999	0.2810	-0.0009	-0.0578	0.24
		(0.07*)	(0.04**)	(0.40)	(0.1*)	(0.01***)	(0.39)	(0.04**)	
1998	39	0.0089	-0.0123	0.0001	0.0294	0.0513	0.0032	-0.0255	0.17
		(0.29)	(0.01***)	(0.47)	(0.27)	(0.26)	(0.27)	(0.16)	
1999	43	-0.0009	-0.0117	0.0001	-0.0198	-0.0749	0.0064	-0.0065	0.32
		(0.48)	(0.003***)	(0.48)	(0.33)	(0.1*)	(0.07*)	(0.39)	
2000	38	-0.0106	-0.0114	0.0039	-0.2255	-0.2592	0.0000	-0.0371	0.37
		(0.38)	(0.1*)	(0.1*)	(0.04**)	(0.01***)	(0.5)	(0.19)	
2001	48	0.0298	-0.0040	-0.0012	-0.0982	0.0368	-0.0035	-0.0282	0.26
		(0.07*)	(0.18)	(0.26)	(0.001***)	(0.32)	(0.14)	(0.1*)	
2002	44	0.0075	-0.0043	0.0028	-0.1362	-0.0694	-0.0166	-0.0520	0.32
		(0.38)	(0.24)	(0.12)	(0.05**)	(0.1*)	(0.05**)	(0.04**)	
2003	54	0.0357	-0.0072	-0.0011	-0.0370	0.1148	-0.0024	-0.0463	0.27
		(0.04**)	(0.04**)	(0.27)	(0.26)	(0.01***)	(0.43)	(0.06*)	
2004	52	0.0346	-0.0082	0.0004	-0.0818	0.0942	0.0107	-0.0924	0.24
		(0.03**)	(0.02**)	(0.47)	(0.1*)	(0.08*)	(0.33)	(0.001***)	
Fixed effects	471	0.0204	-0.0055	0.0002	-0.0782	0.0033	-0.0014	-0.0590	0.17
		(0.001***)	(<0.0001***)	(0.36)	<0.0001***	(0.32)	(0.21)	(<0.0001***)	

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC4 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

The results reveal that coefficient estimates on the test variable, *REQ* are consistently negative and significant in all the four regression models as predicted in the hypothesis. T-statistics for *REQ* obtained from model 1 (model 2) regressions are -2.41 and (-2.27) each is significant at P<0.05. T-statistics for model 3 (model 4) are -4.28 (-4.54) each significant at P<0.0001. These findings confirm Hypothesis 3 that discretionary accruals are significantly lower for electric utilities in the year they request a rate increase than for the same utilities in the years in which a rate increase is not requested. All the four regression models predict lowering of discretionary accruals to manage earnings downward in the year a rate increase request is submitted.

Findings further indicate that the relationships between Discretionary Accruals (*DACC*) and control variables are generally consistent with predictions from theory and prior findings. The coefficient for Cash Flow from Operations (*CFO*) is consistently negative and significant. T-statistics are -12.01, -12.00, -2.34, and -2.38 for regression models 1, 2, 3, and 4 respectively. T-statistics of model 1 and model 2 are each significant at P<0.01 while those for model 3 and model 4 are each significant at P<0.05. This result is consistent with prior findings (Becker at al. 1998, Chung and Kallapur 2003, and Frankel et al. 2002). The coefficient for *SIZE* is negative and significant in models 1 and 2. The T-statistic for model 1 is -2.26 and for model 2 is -2.16, each significant at P<0.05. Finding on *SIZE* variable is consistent with Ashbaugh et al. 2003, and Butler et al. 2004. The coefficient for *GROWTH* is positive and significant at P<0.1 in model 2 consistent with the finding by Menon and Williams 2004. The coefficient for Leverage (*LEV*) is negative and significant in all the four regression models (P<0.01). This finding is contradictory to that by Dichev and Skinner 2002, and DeFond and Jiambalvo 1994. It appears that leverage for rate-regulated utilities is inversely related to discretionary accruals, i.e., firms with high equity to debt capital structure are associated with the high discretionary accruals.

Results of annual cross-sectional regressions reported in Table 11 indicate that *REQ* is significantly negative at conventional levels in at least five years. Results of pooled regressions with fixed time effects (year dummies) provide further evidence that the test variable *REQ* is significantly negative at conventional levels for earnings management metrics, *DACC3* and *DACC4* ($p<0.01$) and marginally significant for *DACC1 and DACC2.* These results are consistent with Hypothesis 3 and suggest that rate-regulated electric utilities have depressed levels of discretionary accruals and therefore earnings in the year they file for rate increase.

4.4.1 Results of Additional Tests Involving Regulatory Assets

Evidence exists that utilities manage earnings downward in the years they request for rate increases (Table 11). The associated question then is; how do managed earnings arise? Specifically, do utilities use regulatory assets to manage earnings?

Table 12 presents Fama and MacBeth cross-sectional regressions results of total accruals (*TAC*) regressed on regulatory assets (*REGASSET*) in addition to the traditional variables used in accrual models, i.e., Jones (1991) model and its modified versions. The results indicate that regulatory assets are not significantly related to total accruals. The coefficient on *REGASSET* is marginally significant in models 5 and 6 with p-values of 0.15 and 0.11 respectively. The coefficient is insignificant in models 7 and 8. In all the four models, *REGASSET* variable has a negative sign, consistent with the fact that regulatory assets get written-off or amortize over time. This finding does not support the proposition that electric utilities use regulatory assets to manipulate earnings. This result is consistent with the tests of Hypothesis 1, i.e., that regulatory oversight diminishes earnings management in rate-regulated electric utilities. Perhaps because regulators must approve regulatory-asset provisions, it is not surprising to find that regulatory assets are not actively manipulated by utility managers. However, the measurement of regulatory assets includes deferred income tax accounts and may be noisy. Further isolation of regulatory asset components in deferred tax accounts may reduce measurement error. This task is left for future research.

Findings further indicate that *CFO* has an expected negative sign and is significant at P<0.0001 level. Similarly, *PPE* is significant at P<0.0001 in model 5 and model 6; and p<0.05 in model 7 and model 8. These findings are consistent with prior literature that finds depreciation of *PPE* as an important accrual variable (Jones 1991). Δ*SALES* and (Δ*SALES* - Δ*REC)* have insignificant coefficients. These findings suggest that electric utilities may be using long-term asset accruals but not working capital accruals to manage earnings.

Table 12
Results of Regressions Based on the Standard Jones and Modified Jones Models with Regulatory Assets as Additional Independent Variable

Model 5: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta SALES_t + \beta_2\ PPE_t + \beta_3 REGASSET_t + \varepsilon_t$
Model 6: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1(\ \Delta SALES_t - \Delta REC_t) + \beta_2\ PPE_t + \beta_3 REGASSET_{t} + \varepsilon_t$
Model 7: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta\ SALES_t + \beta_2\ PPE_t + \beta_3\ CFO_t + \beta_4\ REGASSET_{t} + \varepsilon_t$
Model 8: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ (\Delta\ SALES_t - \Delta REC_t) + \beta_2\ PPE_t + \beta_3\ CFO_t + \beta_4\ REGASSET + \varepsilon_t$

Variables	Model 5	Model 6	Model 7	Model 8
$1/ASSETS_{t-1}$	2.43	2.43	1.29	1.29
	(0.24)	(0.24)	(0.34)	(0.34)
ΔSALES	-0.02		0.012	
	(0.32)		(0.27)	
ΔSALES-ΔREC		-0.02		0.012
		(0.32)		(0.27)
PPE	-0.04***	-0.04***	0.01**	0.01**
	(<0.0001)	(<0.0001)	(0.04)	(0.04)
CFO			-0.711***	-0.711***
			(<0.0001)	(<0.0001)
REGASSET	-0.021	-0.025	-0.002	-0.003
	(0.15)	(0.11)	(0.44)	(0.40)
R^2	0.69	0.69	0.69	0.69

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
TAC = Total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
REGASSET = Regulatory assets scaled by lagged assets

5. ROBUSTNESS TESTS

5.1 Hypothesis 1

5.1.1 Elimination of Firms that Requested for Rate Increases

Hypothesis 1 tests whether absolute discretionary accruals of rate-regulated electric utilities are significantly different from those for matched control firms. In testing this hypothesis, I use a sample of firms shown on Table 1. However, after reconciling utilities in sample one with those in sample two, some sample one utilities were found to have petitioned for rate increases. In tests of Hypothesis 3, I find that utilities petitioning for rate increases depressed discretionary accruals during the years of rate requests. Therefore, including electric utilities that petitioned for rate increases potentially biases discretionary accruals downward and confounds Hypothesis 1 results. In robustness tests, I eliminate firms that petitioned for rate increases in tests of Hypothesis 1. Table 13 reports univariate test results after excluding rate increase requesting firms. Results indicate that mean absolute discretionary accruals for rate-regulated electric utilities are significantly lower than those for matched control firms for model 1 through model 4 estimations. Tests of differences in mean discretionary accruals between rate-regulated utilities and matched control firms gives T-statistics of 3.84, 3.12, 3.93, and 4.29 for model 1, model 2, model 3 and model 4 estimations respectively. Each T-statistic is significant at $P<0.0001$.

Table 14 reports Multivariate test results of cross-sectional estimation of discretionary accruals with an indicator variable of rate regulation after excluding rate increase requesting firms. Multivariate results indicate that the indicator variable for rate regulation, *RATE_REG* is negative and statistically significant in all the four regression models.

Table 13
Robustness Tests of Hypothesis 1: Univariate Test Results After Elimination of Rate-Increase Requesting Firms

Model 1: $\left| TAC_t \right| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$

Model 2: $\left| TAC_t \right| = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\,\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$

Model 3: $\left| TAC_t \right| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$

Model 4: $\left| TAC_t \right| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$

	Model 1	**Model 2**	**Model 3**	**Model 4**
Mean absDACC Control	0.1221	0.1538	0.2275	0.2229
Mean absDACC, Utilities	0.024	0.025	0.0174	0.0159
Diff. in means absDACC	0.098	0.1288	0.2101	0.207
T-statistic	3.84***	3.12***	3.93***	4.29***
P-value	<0.0001	<0.0001	<0.0001	<0.0001
n (Pairs)	96	96	96	96

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (two-tailed test)
|TAC| = Absolute total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
absDACC = Absolute discretionary accruals, residuals from the above models

In each Model, the *RATE_REG* coefficient is significantly negative at p<0.0001. Moreover the models retain sufficient explanatory power, each with R-squared of 0.60 or better.

Robustness test results, both univariate and multivariate presented in Tables 13 and 14 respectively indicate that primary results of Hypothesis 1 are not sensitive to the elimination of firms that petitioned for rate increases during the study period. Primary results of Hypothesis 1 that rate-regulated electric utility firms have significantly lower absolute discretionary accruals than non-regulated matched control firms remain unchanged.

Table 14
Robustness Tests of Hypothesis 1: Multivariate Test Results of Cross-Sectional Estimation of Discretionary Accruals with an Indicator Variable of Rate Regulation After Elimination of Rate Increase Requesting Firms
Coefficient (p-value)

Model 1: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta 3 RATE\_REG_t + \sum\alpha_{,j} YDUM_t + \varepsilon_t$
Model 2: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta 3\,RATE\_REG_t + \sum\alpha_{,j} YDUM_t + \varepsilon_t$
Model 3: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,RATE\_REG_t + \sum\alpha_{,j} YDUM_t + \varepsilon_t$
Model 4 : $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \beta_4\,RATE\_REG_t + \sum\alpha_{,j} YDUM_t + \varepsilon_t$

Variables	Model 1	Model 2	Model 3	Model 4
$1/ASSETS_{t-1}$	7.098	7.244	7.132	7.075
	(0.24)	(0.23)	(0.21)	(0.22)
ΔSALES	0.003		-0.019*	
	(0.80)		(0.08)	
ΔSALES-ΔREC		0.009		-0.014
		(0.47)		(0.24)
PPE	0.02***	0.019***	0.008	0.007
	(0.005)	(0.006)	(0.24)	(0.29)
CFO			0.25***	0.253***
			(<0.0001)	(<0.0001)
RATE_REG	-0.038***	-0.037***	-0.025***	-0.024***
	(<0.0001)	(<0.0001)	(<0.0001)	(<0.0001)
n	563	563	563	563
R^2	0.60	0.60	0.64	0.64

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (two-tailed test)
│TAC│ = Absolute total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
RATE_REG = An indicator variable that equals one for rate-regulated electric utilities and zero for matched control firms
YDUM = Year dummy

5.1.2 Whether a Possibility of a Structural Change Affected Time Series Results

In univariate tests of Hypothesis 1, I use 1994-2001 as estimation period and 2002-2005 as event period. However, in tests of Hypothesis 2 on whether deregulation increases or decreases the magnitude of earnings management, I estimate cross-sectional models from year 2000 to 2005. I commence the post-deregulation period in year 2000 because most states deregulated their electric utility industry in 1999. The partitioning of the sample periods is not consistent between tests of Hypothesis 1 and Hypothesis 2. If deregulation created a structural change, time series results of Hypothesis 1 tests may not hold. I conduct robustness tests to examine whether deregulation caused instability in coefficients that may have affected time series results of Hypothesis one. I change partitioning of the sample period in tests of Hypothesis 1 to agree with that used in Hypothesis 2. Accordingly, 1994-1999 becomes the new estimation period and 2000-2005 the new event period, then re-estimate models 1 through 4. Table 15 reports results of these re-estimations. Results indicate that the mean absolute discretionary accruals of rate-regulated electric utilities are significantly lower than those for matched control firms. The T-statistics for tests of the difference in mean absolute discretionary accruals are 4.54, 4.44, 4.76, and 4.75 for model 1, model 2, model 3, and model 4 estimations respectively. Each T-statistic is significant at $p<0.0001$.

This test indicates that even after altering the estimation and event period periods in order to discount the possibility of a structural shift associated with deregulation, the primary result of Hypothesis 1 remain unchanged; absolute discretionary accruals of rate-regulated utilities are significantly lower than those for matched control firms. However, shortening the estimation and lengthening the event period is inappropriate from econometrics stand point because the efficiency of the estimators is compromised. For this reason, prior studies on earnings management that use time series research designs e.g., Jones (1991) ensure that there are as many observations (i.e., years) as possible in the estimation period relative to the event period.

Table 15
Robustness Test Results of Hypothesis 1 for a Possibility of a Structural Change Due to Deregulation

Model 1: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$
Model 2: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$
Model 3: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$
Model 4: $|TAC_t| = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$

	Model 1	**Model 2**	**Model 3**	**Model 4**
Mean absDACC, Control	0.1029	0.1307	0.1142	0.1142
Mean absDACC, Utilities	0.0535	0.0535	0.049	0.0483
Diff. in means absDACC	0.0494	0.0772	0.0652	0.0659
T-statistic	4.54***	4.44***	4.76***	4.75***
p-value	<0.0001	<0.0001	<0.0001	<0.0001
n (Pairs)	282	282	282	282

***, ***, * Denote significance at 0.01, 0.05, and 0.1, respectively (two-tailed test)
|TAC| = Absolute total accruals scaled by lagged assets
ΔSALES = Change in sales scaled by lagged assets
ΔREC = Change in receivables scaled by lagged assets
PPE = Plant, property and equipment scaled by lagged assets
CFO = Cash flow from operations scaled by lagged assets
absDACC = Absolute discretionary accruals, residuals from the above models

5.2 Hypothesis 3

5.2.1 Reversal of Accruals

Accruals by their very nature reverse over time. Hypothesis 3's results indicate that utility firms use accruals to manage earnings downward in the year they file for rate increase. I therefore conduct robustness tests to evaluate whether and when these accruals reverse. If electric utility firms actually used working capital accruals to manage earnings, then accruals are expected to reverse a year later. However, if on the other hand, electric utilities use long-term accruals to manage earnings, accruals are not expected to reverse so quickly. I therefore repeat tests of Hypothesis 3 using the year after the rate requests and two years subsequent to the rate request. Table 16, Panel A-D reports annual cross-sectional, a pooled one-way fixed effects model and Fama and MacBeth cross-sectional results of discretionary accruals regressed on an indicator variable for the presence of a rate increase request and control variables in the year after the rate request.

Table 16
Robustness Tests of Hypothesis 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year After Request
Coefficient (P-value)

Panel A
Model: $DACC1_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1995	38	0.1516	-0.0032	-0.0055	-0.7554	-0.013	0.0162	-0.1072	0.66
		(<0.0001***)	(0.28)	(0.02**)	(<0.0001***)	(0.25)	(0.13)	(<0.0001***)	
1996	39	0.0255	-0.0049	-0.0027	-0.4236	-0.0869	-0.0202	0.0969	0.55
		(0.13)	(0.16)	(0.08*)	(0.0003***)	(0.20)	(0.08*)	(0.004***)	
1997	39	0.1162	0.0012	-0.0030	-0.3417	0.3536	0.0057	-0.1299	0.32
		(0.002***)	(0.44)	(0.16)	(0.01***)	(0.05**)	(0.17)	(0.02***)	
1998	39	0.0433	-0.0109	0.0006	-0.4995	0.0392	-0.0030	0.0039	0.62
		(0.05**)	(0.1*)	(0.40)	(<0.0001***)	(0.39)	(0.36)	(0.46)	
1999	41	0.1101	0.0016	-0.0053	-0.7576	-0.1428	-0.0169	-0.0353	0.77
		(0.0002***)	(0.43)	(0.01***)	(<0.0001***)	(0.09*)	(0.02**)	(0.20)	
2000	41	0.0159	-0.0256	0.0031	-0.4726	-0.2848	-0.0118	-0.0322	0.37
		(0.35)	(0.006***)	(0.20)	(0.001***)	(0.005***)	(0.15)	(0.25)	
2001	45	0.0366	0.0027	0.0019	-0.6831	-0.3251	-0.0198	-0.0431	0.75
		(0.14)	(0.40)	(0.29)	(<0.0001***)	(0.006***)	(0.0009***)	(0.19)	
2002	45	0.0970	-0.0027	-0.0010	-0.7611	-0.1999	0.0193	-0.0660	0.63
		(0.006***)	(0.37)	(0.39)	(<0.0001***)	(0.001***)	(0.09*)	(0.06*)	
2003	52	0.0790	-0.0060	-0.0010	-0.5551	0.0804	0.0320	-0.0729	0.46
		(0.01***)	(0.22)	(0.37)	(<0.0001***)	(0.1*)	(0.07*)	(0.07*)	
2004	54	0.0812	-0.0015	-0.0021	-0.5873	0.0361	0.0578	-0.0742	0.55
		(0.0002***)	(0.38)	(0.15)	(<0.0001***)	(0.33)	(0.02**)	(0.02**)	
2005	49	-0.0046	-0.0089	0.0054	-0.8424	-0.0592	0.0667	-0.0085	0.81
		(0.40)	(0.03**)	(0.003***)	(<0.0001***)	(0.12)	(0.0004***)	(0.38)	
Fixed effects	482	0.0573	-0.0050	-0.0013	-0.5677	-0.0316	-0.0024	-0.0521	0.5
		(<0.0001***)	(0.011**)	(0.07*)	(<0.0001***)	(0.03**)	(0.20)	(<0.0001***)	

Fama and Mac-Beth procedure: T-Test to determine whether the test variable, *REQ* is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.005	-2.20**

Table 16 (Continued)
Robustness Tests of Hypothesis 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year After Request
Coefficient (P-value)

Panel B
Model: $DACC2_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1995	38	0.1522	-0.0035	-0.0055	-0.7576	-0.0124	0.0211	-0.1079	0.68
		(<0.0001***)	(0.25)	(0.02**)	(<0.0001***)	(0.25)	(0.07*)	(<0.0001***)	
1996	39	0.0255	-0.0048	-0.0027	-0.4227	-0.0860	-0.0189	0.0965	0.55
		(0.13)	(0.16)	(0.08*)	(0.0003***)	(0.20)	(0.09*)	(0.004***)	
1997	39	0.1161	0.0011	-0.0030	-0.3437	0.3518	0.0057	-0.1293	0.32
		(0.002***)	(0.44)	(0.16)	(0.01***)	(0.06*)	(0.17)	(0.02***)	
1998	39	0.0440	-0.0108	0.0006	-0.5005	0.0389	-0.0038	0.0032	0.62
		(0.05**)	(0.1*)	(0.41)	(<0.0001***)	(0.39)	(0.32)	(0.47)	
1999	41	0.1082	0.0018	-0.0052	-0.7546	-0.1437	-0.0133	-0.0357	0.77
		(0.0002***)	(0.42)	(0.01***)	(<0.0001***)	(0.09*)	(0.04**)	(0.19)	
2000	41	0.0159	-0.0256	0.0031	-0.4725	-0.2853	-0.0119	-0.0323	0.37
		(0.35)	(0.006***)	(0.20)	(0.001***)	(0.005***)	(0.15)	(0.25)	
2001	46	0.0348	-0.0010	0.0010	-0.6852	-0.3270	-0.0204	-0.0139	0.74
		(0.16)	(0.47)	(0.39)	(<0.0001***)	(0.007***)	(0.0007)	(0.36)	
2002	45	0.0962	-0.0023	-0.0010	-0.7589	-0.2021	0.0207	-0.0642	0.62
		(0.007***)	(0.39)	(0.39)	(<0.0001***)	(0.001***)	(0.08*)	(0.07*)	
2003	51	0.0788	-0.0056	-0.0010	-0.5633	0.0749	0.0452	-0.0725	0.48
		(0.01***)	(0.23)	(0.37)	(<0.0001***)	(0.16)	(0.02**)	(0.07*)	
2004	53	0.0972	-0.0036	-0.0036	-0.5566	0.0340	0.0409	-0.0762	0.59
		(<0.0001***)	(0.20)	(0.20)	(<0.0001***)	(0.33)	(0.07*)	(0.01***)	
2005	49	-0.0104	-0.0079	0.0049	-0.8294	-0.0645	0.0946	0.0090	0.83
		(0.27)	(0.04**)	(0.005***)	(<0.0001***)	(0.08*)	(<0.0001***)	(0.37)	
Fixed effects	481	0.0595	-0.0052	-0.0018	-0.5739	-0.0458	-0.0025	-0.0440	0.5
		(<0.0001***)	(0.01***)	(0.02**)	(<0.0001***)	(0.003***)	(0.19)	(0.0002***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T- statistic
REQ	-0.006	-2.47**

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC1 (appearing in the prior page) = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t) + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 16 (Continued)
Robustness Tests of Hypothesis 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year After Request
Coefficient (P-value)

Panel C
Model: $DACC3_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1995	38	0.0548	-0.0019	-0.0016	-0.0886	-0.0095	0.0084	-0.0964	0.64
		(0.0006***)	(0.27)	(0.14)	(0.08*)	(0.2)	(0.16)	(<0.0001***)	
1996	38	-0.0081	-0.0045	-0.0008	-0.0816	-0.0777	-0.0096	0.0579	0.18
		(0.36)	(0.13)	(0.29)	(0.20)	(0.19)	(0.21)	(0.09*)	
1997	38	0.0248	-0.0094	0.0005	0.0357	0.1724	-0.0014	-0.0604	0.28
		(0.11)	(0.02**)	(0.38)	(0.32)	(0.07*)	(0.34)	(0.03**)	
1998	39	0.0017	-0.0024	0.0001	0.0241	0.0489	-0.0011	-0.0052	0.03
		(0.46)	(0.33)	(0.47)	(0.32)	(0.29)	(0.42)	(0.43)	
1999	41	0.0010	-0.0033	-0.0001	0.0033	-0.0527	0.0044	-0.0094	0.05
		(0.48)	(0.28)	(0.46)	(0.47)	(0.21)	(0.18)	(0.36)	
2000	40	-0.0145	-0.0266	0.0059	-0.2281	-0.2294	-0.0066	-0.0627	0.42
		(0.33)	(0.001***)	(0.03**)	(0.03**)	(0.01***)	(0.24)	(0.06*)	
2001	48	0.0266	-0.0032	-0.0011	-0.0916	0.0412	-0.0038	-0.0229	0.25
		(0.09*)	(0.29)	(0.27)	(0.001***)	(0.29)	(0.12)	(0.14)	
2002	44	0.0126	-0.0105	0.0022	-0.1549	-0.1190	-0.0066	-0.0502	0.47
		(0.30)	(0.04**)	(0.16)	(0.02**)	(0.003***)	(0.26)	(0.04**)	
2003	52	0.0346	-0.0103	-0.0003	-0.0209	0.1231	-0.0219	-0.0636	0.27
		(0.05**)	(0.02**)	(0.44)	(0.36)	(0.001***)	(0.05**)	(0.02**)	
2004	54	0.0394	-0.0038	-0.0007	-0.1054	0.0411	-0.0015	-0.0857	0.22
		(0.01***)	(0.16)	(0.34)	(0.07*)	(0.27)	(0.48)	(0.002***)	
2005	51	-0.0031	-0.0031	0.0018	-0.0204	-0.0183	0.0031	-0.0346	0.08
		(0.42)	(0.23)	(0.15)	(0.36)	(0.34)	(0.42)	(0.08*)	
Fixed effects	483	0.0173	-0.0059	0.0004	-0.0650	-0.0076	-0.0018	-0.0506	0.14
		(0.002***)	(<0.0001***)	(0.22)	(<0.0001***)	(0.25)	(0.16)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.007	-3.31***

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC3 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 16 (Continued)
Robustness Tests of Hypothesis 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year After Request
Coefficient (P-value)

Panel D
Model: $DACC4_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β1	β2	β3	β4	β5	β6	R2
1995	38	0.0554	-0.002	-0.0017	-0.0919	-0.0093	0.0099	-0.0967	0.65
		(0.0005***)	(0.25)	(0.13)	(0.07*)	(0.2)	(0.12)	(<0.0001***)	
1996	38	-0.0086	-0.0046	-0.0008	-0.0820	-0.0783	-0.0071	0.0579	0.17
		(0.35)	(0.12)	(0.30)	(0.19)	(0.19)	(0.27)	(0.09*)	
1997	39	0.0400	-0.0075	-0.0020	0.0765	0.2159	0.0007	-0.0556	0.2
		(0.06*)	(0.08*)	(0.16)	(0.22)	(0.07*)	(0.42)	(0.08*)	
1998	39	0.0017	-0.0024	0.0001	0.0237	0.0499	-0.0009	-0.0052	0.03
		(0.46)	(0.33)	(0.47)	(0.32)	(0.29)	(0.43)	(0.43)	
1999	41	0.0008	-0.0032	-0.0001	0.0027	-0.0529	0.0049	-0.0095	0.05
		(0.48)	(0.28)	(0.47)	(0.48)	(0.21)	(0.16)	(0.35)	
2000	40	-0.0144	-0.0265	0.0059	-0.2279	-0.2316	-0.0068	-0.0632	0.42
		(0.33)	(0.001***)	(0.03**)	(0.03**)	(0.01***)	(0.23)	(0.06*)	
2001	48	0.0265	-0.0032	-0.0011	-0.0915	0.0399	-0.0034	-0.0237	0.25
		(0.09*)	(0.29)	(0.27)	(0.001***)	(0.29)	(0.14)	(0.13)	
2002	44	0.0115	-0.0100	0.0022	-0.1527	-0.1221	-0.0059	-0.0479	0.46
		(0.32)	(0.05**)	(0.16)	(0.02**)	(0.002***)	(0.23)	(0.05**)	
2003	52	0.0364	-0.0101	-0.0004	-0.0324	0.1293	-0.0084	-0.0637	0.29
		(0.04**)	(0.02**)	(0.41)	(0.29)	(0.001***)	(0.26)	(0.02**)	
2004	54	0.036	-0.0046	-0.0005	-0.1032	0.0479	0.0068	-0.0784	0.19
		(0.02**)	(0.13)	(0.38)	(0.08*)	(0.25)	(0.39)	(0.005***)	
2005	51	-0.0024	-0.0031	0.0015	-0.0263	-0.0147	0.0160	-0.0311	0.07
		(0.44)	(0.23)	(0.20)	(0.32)	(0.37)	(0.16)	(0.11)	
Fixed effects	484	0.0183	-0.0059	0.0002	-0.0609	-0.0057	-0.0005	-0.0494	0.13
		(0.001***)	(<0.0001***)	(0.34)	(0.0001***)	(0.30)	(0.39)	(<0.0001***)	

Fama and Mac-Beth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.007	-3.30***

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC4 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

The results reveal that coefficient estimates on the test variable*, REQ* are consistently negative significantly in all the four regression models. Fama and MacBeth T-statistics for the variable *REQ* obtained from models1 and 2 are -2.20 and -2.47 respectively each is significant at $p<0.05$. T-statistics for models 3 and 4 are -3.31 and -3.30 respectively, each significant at $p<0.0001$.

Results of a pooled regression with fixed time effects (year dummies) provides further evidence that the test variable *REQ* is significantly negative at conventional levels for all the four earnings management metrics, *DACC1, DACC2, DACC3*, and *DACC4*.

Results of individual year cross-sectional estimations indicate that *REQ* is significantly negative at conventional levels in 3, 3, 4, and 4 annual regressions using model 1, model 2, model 3, and model 4 respectively. These results present evidence that accruals do not reverse one year after rate request. On the contrary, the findings suggest that earnings management continues a year after a rate increase request is submitted. This finding is plausible given the fact that the regulatory lag, the time between the submission of a rate request and its approval, is about nine months. In addition, once the PUC approves a rate increase request, a test period of up to a year is established. During the test period, the PUC monitors whether the utility's profitability as measured by return on equity (*ROE*) exceeds that allowed by the commission. It is not surprising then for a utility to continue managing earnings a year later. Furthermore, these findings are consistent with the argument that relevant costs and revenues for decision making are future costs and revenues. The findings suggest that PUC base approval of rate increase requests on future performance. These arguments are consistent with earnings management continuing a year after the submission of a rate request.

Motivated to examine whether accruals reverse, I extend multivariate tests of Hypothesis 3 to the second year after the submission of the rate request. Table 17, Panel A-D reports Fama and MacBeth cross-sectional regression results and those from fixed effects model along with annual cross-sectional regressions in the second year after the submission of a rate request. The Fama and MacBeth analysis results indicate that the average coefficients for the test variable, *REQ*, are indistinguishable from zero with T-statistics of -1.26, -1.18, -1.26 and -1.25 for regressions based on model 1, model 2, model3, and model 4 respectively. Negative and significant coefficients for the test variable *REQ*, observed in the year of request, and the year following the request, disappear in the second year following the request. Results of pooled estimations with fixed time effects indicate that *REQ* is still significant at conventional levels but at lower magnitudes than in the year of request and the year following. In individual year cross-sectional regressions, only 2, 2, 3, and 3 years two out of 11 years have significant *REQ* coefficients in model 1, model 2, model 3, and model 4 regressions respectively.

The results of pooled estimations with fixed time effects are puzzling. The test variable *REQ*, is significantly negative at conventional levels and yet individual year cross-sectional regressions and Fama and MacBeth analysis suggest the opposite. It could be that cross-sectional dependence, i.e., positive cross-sectional correlation of residuals may be overstating inferences in pooled regressions, even after including fixed time effects to mitigate the problem. Tucker and Zarowin (2006) raise this as valid concern and use Fama and MacBeth analysis in an attempt to avoid this potential problem. The preponderance of evidence depicted in Table 17 is that accruals reverse (to some degree) in the second year following the year of rate request. If the analysis is extended to several years following the rate request, it may be possible to find evidence that accruals completely reverse.

Table 17
Robustness Tests of Hypothesis 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request

Coefficient (P-value)

Panel A

Model: $DACC1_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1996	38	0.0294	-0.0044	-0.0027	-0.4277	-0.0035	-0.0241	0.1011	0.51
		(0.132)	(0.18)	(0.12)	(0.0004***)	(0.38)	(0.05**)	(0.003***)	
1997	39	0.1265	-0.0137	-0.0043	-0.4252	0.2400	0.0086	-0.1149	0.39
		(0.0005***)	(0.03**)	(0.07*)	(0.002***)	(0.12)	(0.07*)	(0.02***)	
1998	39	0.0434	-0.0024	0.0017	-0.5137	0.0662	-0.0035	-0.0151	0.61
		(0.05**)	(0.36)	(0.25)	(<0.0001***)	(0.31)	(0.34)	(0.36)	
1999	41	0.1055	-0.0111	-0.0058	-0.7402	-0.1810	-0.0173	-0.0177	0.8
		(0.0002***)	(0.07*)	(0.06*)	(<0.0001***)	(0.04**)	(0.01***)	(0.33)	
2000	39	-0.0147	0.0176	0.0032	-0.4105	-0.3193	-0.0054	0.0206	0.39
		(0.36)	(0.06*)	(0.19)	(0.003***)	(0.005***)	(0.32)	(0.34)	
2001	48	0.0411	-0.0084	0.0018	-0.7136	-0.2764	-0.0203	-0.0323	0.74
		(0.11)	(0.19)	(0.300	(<0.0001***)	(0.017**)	(0.006***)	(0.26)	
2002	44	0.0998	-0.0074	-0.0010	-0.7642	-0.1430	0.0219	-0.0638	0.62
		(0.005***)	(0.27)	(0.29)	(<0.0001***)	(0.03**)	(0.06*)	(0.07*)	
2003	51	0.0781	0.0018	0.0018	-0.6111	0.0722	0.0270	-0.0770	0.5
		(0.01***)	(0.40)	(0.40)	(<0.0001***)	(0.12)	(0.1*)	(0.06*)	
2004	52	0.0834	-0.0040	-0.0023	-0.5915	0.0302	0.0663	-0.0776	0.56
		(0.0002***)	(0.23)	(0.13)	(<0.0001***)	(0.36)	(0.015**)	(0.01***)	
2005	52	-0.0003	-0.0026	0.0044	-0.8216	-0.0559	0.0526	-0.0018	0.82
		(0.49)	(0.26)	(0.01***)	(<0.0001***)	(0.13)	(0.001***)	(0.48)	
Fixed effects	443	0.0493	-0.0037	-0.0006	-0.5903	-0.0079	-0.0034	-0.0382	0.54
		(<0.0001***)	(0.06*)	(0.24)	(<0.0001***)	(0.27)	(0.12)	(0.003***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.003	-1.26

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)

DACC1 = Signed discretionary accrual, residual from the following estimation:

$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]

REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise

SIZE = Natural log of total assets

CFO = Cash flow from operations scaled by lagged assets

LG_TAC = Lagged total accruals scaled by lagged assets

GROWTH = Sales growth

LEV =Leverage defined as total debt divided by total assets

Table 17 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request

Coefficient (P-value)

Panel B

Model: $DACC2_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1996	38	0.0295	-0.0045	-0.0028	-0.4278	-0.0036	-0.0227	0.1011	0.51
		(0.131)	(0.18)	(0.12)	(0.0004***)	(0.37)	(0.06**)	(0.003***)	
1997	39	0.1264	-0.0138	-0.0043	-0.4274	0.2379	0.0086	-0.1149	0.39
		(0.0005***)	(0.03**)	(0.07*)	(0.002***)	(0.13)	(0.07*)	(0.02***)	
1998	39	0.0441	-0.0024	0.0016	-0.5146	0.0657	-0.0043	-0.0151	0.61
		(0.06**)	(0.36)	(0.26)	(<0.0001***)	(0.32)	(0.30)	(0.36)	
1999	41	0.1038	-0.0112	-0.0056	-0.7375	-0.1829	-0.0136	-0.0177	0.78
		(0.0002***)	(0.065*)	(0.07*)	(<0.0001***)	(0.04**)	(0.03**)	(0.33)	
2000	39	-0.0146	0.0176	0.0032	-0.4104	-0.3199	-0.0055	0.0206	0.39
		(0.37)	(0.06*)	(0.19)	(0.003***)	(0.005***)	(0.32)	(0.34)	
2001	48	0.0331	-0.0076	0.0013	-0.6953	-0.3227	-0.0196	-0.0323	0.75
		(0.15)	(0.20)	(0.34)	(<0.0001***)	(0.005***)	(0.0005***)	(0.26)	
2002	44	0.0996	-0.0075	-0.0010	-0.7614	-0.1456	0.0232	-0.0638	0.6
		(0.006***)	(0.27)	(0.38)	(<0.0001***)	(0.03**)	(0.06*)	(0.07*)	
2003	52	0.0768	0.0027	0.0012	-0.5639	0.0769	0.0492	-0.0770	0.48
		(0.01***)	(0.36)	(0.34)	(<0.0001***)	(0.103)	(0.01***)	(0.06*)	
2004	52	0.0805	-0.0039	-0.0021	-0.5909	0.0379	0.0686	-0.0776	0.55
		(0.0003***)	(0.24)	(0.15)	(<0.0001***)	(0.32)	(0.013**)	(0.01***)	
2005	52	-0.0038	-0.0022	0.0038	-0.7933	-0.0624	0.0783	-0.0018	0.83
		(0.41)	(0.29)	(0.02**)	(<0.0001***)	(0.09*)	(<0.0001***)	(0.48)	
Fixed effects	444	0.0461	-0.0032	-0.0008	-0.5628	-0.0062	-0.0018	-0.0382	0.51
		(<0.0001***)	(0.09*)	(0.20)	(<0.0001***)	(0.32)	(0.26)	(0.003***)	

Fama and MacBeth procedure: T-Test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.003	-1.18

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC2 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise.
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 17 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request
Coefficient (P-value)

Panel C
Model: $DACC3_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1996	37	0.0024	-0.0044	-0.0007	-0.1092	-0.0024	-0.0111	0.0428	0.13
		(0.46)	(0.14)	(0.35)	(0.14)	(0.40)	(0.18)	(0.17)	
1997	39	0.0484	-0.0098	-0.0029	0.0370	0.1716	0.0038	-0.0532	0.24
		(0.03**)	(0.028**)	(0.07*)	(0.35)	(0.12)	(0.18)	(0.09*)	
1998	39	0.0037	-0.0076	0.0002	0.0239	0.0529	-0.0023	-0.0089	0.12
		(0.41)	(0.03**)	(0.46)	(0.32)	(0.26)	(0.32)	(0.36)	
1999	41	-0.0030	-0.0026	-0.0026	0.0123	-0.0489	0.0033	0.0008	0.05
		(0.48)	(0.29)	(0.29)	(0.40)	(0.24)	(0.23)	(0.48)	
2000	38	-0.0408	0.0149	0.0057	-0.1756	-0.2635	-0.0009	-0.0105	0.39
		(0.12)	(0.06*)	(0.03**)	(0.07*)	(0.005***)	(0.46)	(0.40)	
2001	50	0.0261	-0.0079	-0.0010	-0.0882	0.0617	-0.0024	-0.0221	0.27
		(0.08*)	(0.05**)	(0.29)	(0.001***)	(0.19)	(0.21)	(0.14)	
2002	44	0.0078	-0.0019	0.0026	-0.1184	-0.0555	-0.0179	-0.0527	0.32
		(0.38)	(0.41)	(0.14)	(0.06*)	(0.15)	(0.04**)	(0.04**)	
2003	52	0.0335	-0.0014	-0.0008	-0.0317	0.1095	-0.0144	-0.0526	0.2
		(0.06*)	(0.39)	(0.34)	(0.30)	(0.004***)	(0.14)	(0.05**)	
2004	52	0.0361	-0.0026	-0.0003	-0.0988	0.0459	0.0030	-0.0884	0.2
		(0.02**)	(0.28)	(0.44)	(0.08*)	(0.25)	(0.40)	(0.001***)	
2005	53	0.0000	-0.0041	0.0012	-0.0082	-0.0179	-0.0037	-0.0283	0.09
		(0.50)	(0.13)	(0.22)	(0.44)	(0.34)	(0.40)	(0.13)	
Fixed effects	445	0.0131	-0.0034	0.0006	-0.0635	0.0082	-0.0019	-0.0402	0.11
		(0.02**)	(0.015**)	(0.18)	(0.0001***)	(0.17)	(0.16)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.003	-1.27

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC3 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 17 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request
Coefficient (P-value)

Panel D
Model: $DACC4_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	B_2	β_3	β_4	β_5	β_6	R^2
1996	37	0.0021	-0.0045	-0.0007	-0.1108	-0.0025	-0.0085	0.0424	0.13
		(0.47)	(0.13)	(0.36)	(0.13)	(0.39)	(0.24)	(0.17)	
1997	39	0.0482	-0.0097	-0.0029	0.0414	0.1744	0.0036	-0.0540	0.24
		(0.03**)	(0.029**)	(0.08*)	(0.34)	(0.12)	(0.19)	(0.08*)	
1998	39	0.0038	-0.0076	0.0002	0.0234	0.0529	-0.0021	-0.0090	0.12
		(0.42)	(0.03**)	(0.45)	(0.32)	(0.26)	(0.33)	(0.36)	
1999	41	-0.0032	-0.0026	-0.0001	0.0117	-0.0492	0.0038	0.0007	0.05
		(0.43)	(0.29)	(0.47)	(0.40)	(0.22)	(0.20)	(0.49)	
2000	38	-0.0406	0.0149	0.0057	-0.1757	-0.2657	-0.0011	-0.0111	0.39
		(0.13)	(0.06*)	(0.03**)	(0.08*)	(0.004***)	(0.45)	(0.40)	
2001	50	0.0259	-0.0079	-0.0010	-0.0880	0.0602	-0.0020	-0.0229	0.27
		(0.08*)	(0.05**)	(0.29)	(0.001***)	(0.20)	(0.26)	(0.13)	
2002	44	0.0074	-0.0019	0.0025	-0.1154	-0.0588	-0.0172	-0.0512	0.31
		(0.39)	(0.41)	(0.15)	(0.07*)	(0.14)	(0.05**)	(0.05**)	
2003	52	0.0352	-0.0009	-0.0009	-0.0427	0.1161	-0.0120	-0.0530	0.22
		(0.05**)	(0.48)	(0.31)	(0.24)	(0.003***)	(0.46)	(0.05**)	
2004	52	0.0321	-0.0025	-0.0001	-0.0930	0.0568	0.0122	-0.0821	0.17
		(0.04**)	(0.29)	(0.49)	(0.1*)	(0.21)	(0.32)	(0.004***)	
2005	53	0.0012	-0.0043	0.0008	-0.0139	-0.0145	0.0087	-0.0246	0.08
		(0.47)	(0.12)	(0.31)	(0.40)	(0.37)	(0.27)	(0.17)	
Fixed effects	445	0.0124	-0.0033	0.0005	-0.0600	0.0093	-0.0009	-0.0393	0.1
		(0.03**)	(0.018**)	(0.18)	(0.0002***)	(0.15)	(0.32)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.003	-1.25

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC4 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

5.2.2 Alternate Argument: Year Prior to Rate Increase Request

A contrasting argument can be made that management may plan to request a rate increase a year before filing a rate request. If this is true then earnings management might be observed a year prior to making a rate request. Motivated by this alternate argument, I carry out robustness tests of Hypothesis 3 in the year prior to rate request. Results are presented in Table 18, Panel A-D. Fama and MacBeth cross-sectional regression results reveal that the average coefficients are indistinguishable from zero with T-statistics of -0.5, -0.55, -0.86, and -0.86 for models 1 through 4 respectively. Results of fixed effects model reveal that the coefficients for the test variable, *REQ*, are indistinguishable from zero in all models except model 2. These insignificant results provide evidence of no earnings management in the year prior to submission of a rate increase request.

5.2.3 Elimination of Firms that Issue Stock

Healy and Wahlen (1999) identify capital market incentives as a motive for earnings management. Prior studies find that managers use discretionary accruals to manage earnings in order to beat earnings forecasts (Ayers et al. 2006, Dechow et al. 2003, and Phillips et al. 2003). Dechow and Skinner (2000) document that earnings management will likely be greater when it allows managers to meet the analyst forecast. Abarnell and Lehavy (2003) report that firms that have received buy recommendations from analysts are more likely to engage in earnings management in order to meet, or just beat, analysts' forecasts. This study attempts to isolate the approval of a rate increase as an incentive for earnings management. The presence of firms in the sample with a competing capital market incentive (i.e., to increase earnings) for earnings management may weaken the results. To examine the robustness of Hypothesis 3's primary results, I eliminate stock-issuing firms from the sample.

Table 18
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request

Coefficient (P-value)

Panel A

Model: $DACC1_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β1	β2	β3	β4	β5	β6	R^2
1993	38	0.0723	-0.0003	0.0012	-0.5135	0.0076	0.0244	-0.0952	0.53
		(0.008***)	(0.48)	(0.32)	(<0.0001***)	(0.26)	(0.14)	(0.0005***)	
1994	39	0.1127	0.0026	-0.0036	-0.752	-0.2427	0.0507	-0.108	0.72
		(0.0001***)	(0.33)	(0.07*)	(<0.0001***)	(0.03**)	(0.06*)	(0.0001***)	
1995	39	0.137	0.0046	-0.0043	-0.6447	0.2271	0.0144	-0.0963	0.72
		(<0.0001***)	(0.2)	(0.02**)	(<0.0001***)	(0.008***)	(0.14)	(<0.0001***)	
1996	38	0.0244	0.0014	-0.0023	-0.4377	-0.1131	-0.0223	0.0874	0.5
		(0.20)	(0.43)	(0.13)	(0.0004***)	(0.16)	(0.07*)	(0.05**)	
1997	39	0.1158	0.0004	-0.0029	-0.3454	0.3477	0.0056	-0.1282	0.32
		(0.002***)	(0.48)	(0.16)	(0.01***)	(0.06*)	(0.17)	(0.02**)	
1998	41	0.0407	-0.0055	0.0018	-0.5134	0.0691	-0.0004	-0.0110	0.65
		(0.07**)	(0.24)	(0.23)	(<0.0001***)	(0.30)	(0.48)	(0.40)	
1999	41	0.1128	-0.0026	-0.0055	-0.7589	-0.1396	-0.0157	-0.0373	0.77
		(0.0001***)	(0.38)	(0.01***)	(<0.0001***)	(0.1*)	(0.03**)	(0.17)	
2000	38	0.0153	0.0004	0.0023	-0.5250	-0.2950	-0.0101	-0.0033	0.38
		(0.37)	(0.48)	(0.27)	(0.001***)	(0.009***)	(0.20)	(0.47)	
2001	43	0.0537	-0.0009	0.0024	-0.7684	-0.3364	-0.0205	-0.0807	0.82
		(0.05**)	(0.45)	(0.23)	(<0.0001***)	(0.02**)	(0.0001***)	(0.03**)	
2002	46	0.1023	-0.0100	-0.0014	-0.7494	-0.1402	0.0188	-0.0619	0.62
		(0.002***)	(0.08*)	(0.33)	(<0.0001***)	(0.03**)	(0.08*)	(0.06*)	
2003	49	0.0711	0.0028	0.0004	-0.5800	0.0235	0.0151	-0.0856	0.47
		(0.01***)	(0.35)	(0.44)	(<0.0001***)	(0.38)	(0.25)	(0.04**)	
Fixed effects	451	0.0868	-0.0009	-0.0016	-0.6189	-0.0128	-0.0039	-0.0738	0.55
		(<0.0001***)	(0.33)	(0.03**)	(<0.0001***)	(0.15)	(0.07*)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.0006	-0.5

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)

DACC1 = Signed discretionary accruals, residual from the following estimation:

$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]

REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise

SIZE = Natural log of total assets

CFO = Cash flow from operations scaled by lagged assets

LG-TAC = Lag total accruals scaled by lagged assets

GROWTH = Sales growth

LEV =Leverage defined as total debt divided by total assets

Table 18 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request

Coefficient (P-value)

Panel B

$DACC2_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	N	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1993	38	0.0756	-0.0011	0.001	-0.523	0.0079	0.0231	-0.0977	0.54
		(0.005***)	(0.43)	(0.34)	(<0.0001***)	(0.25)	(0.15)	(0.0003***)	
1994	39	0.1134	0.003	-0.0038	-0.7511	-0.2311	0.066	-0.1073	0.71
		(<0.0001***)	(0.31)	(0.06*)	(<0.0001***)	(0.03**)	(0.02**)	(0.0001***)	
1995	39	0.1379	0.0045	-0.0044	-0.6478	0.2216	0.0194	-0.0971	0.73
		(<0.0001***)	(0.20)	(0.02**)	(<0.0001***)	(0.008***)	(0.07*)	(<0.0001***)	
1996	38	0.0243	0.0013	-0.0023	-0.4367	-0.1127	-0.0211	0.0873	0.49
		(0.20)	(0.43)	(0.13)	(0.0004***)	(0.17)	(0.08*)	(0.05**)	
1997	39	0.1157	0.0005	-0.0030	-0.3473	0.3460	0.0056	-0.1276	0.32
		(0.002***)	(0.48)	(0.16)	(0.01***)	(0.06*)	(0.17)	(0.02**)	
1998	41	0.0414	-0.0054	0.0018	-0.5146	0.0687	-0.0012	-0.0115	0.65
		(0.06**)	(0.25)	(0.23)	(<0.0001***)	(0.30)	(0.44)	(0.39)	
1999	41	0.1114	-0.0030	-0.0054	-0.7561	-0.1400	-0.0119	-0.0380	0.77
		(0.0001***)	(0.36)	(0.01***)	(<0.0001***)	(0.1*)	(0.07*)	(0.16)	
2000	38	0.0153	0.0004	0.0023	-0.5248	-0.2955	-0.0102	-0.0035	0.38
		(0.37)	(0.48)	(0.27)	(0.001***)	(0.009***)	(0.19)	(0.47)	
2001	43	0.0554	-0.0010	0.0022	-0.7725	-0.3600	-0.0200	-0.0848	0.82
		(0.05**)	(0.45)	(0.25)	(<0.0001***)	(0.01***)	(0.0002***)	(0.03**)	
2002	46	0.1020	-0.0100	-0.0014	-0.7468	-0.1424	0.0202	-0.0607	0.61
		(0.002***)	(0.09*)	(0.33)	(<0.0001***)	(0.03**)	(0.08*)	(0.07*)	
2003	49	0.0710	0.0029	0.0002	-0.5791	0.0228	0.0302	-0.0827	0.48
		(0.01***)	(0.34)	(0.47)	(<0.0001***)	(0.38)	(0.08*)	(0.04**)	
Fixed effects	451	0.0870	-0.0009	-0.0016	-0.6179	-0.0129	-0.0027	-0.0742	0.55
		(<0.0001***)	(0.34)	(0.02**)	(<0.0001***)	(0.15)	(0.16)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.0007	-0.55

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)

DACC2 = Signed discretionary accrual, residual from the following estimation:

$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]

REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise

SIZE = Natural log of total assets

CFO = Cash flow from operations scaled by lagged assets

LG_TAC = Lagged total accruals scaled by lagged assets

GROWTH = Sales growth

LEV =Leverage defined as total debt divided by total assets

Table 18 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request
Coefficient (P-value)

Panel C
$DACC3_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	n	α	β_1	β_2	β_3	β_4	β_5	β_6	R^2
1993	38	0.0531	-0.0048	0.0005	-0.2136	0.0022	0.0084	-0.1016	0.45
		(0.01***)	(0.17)	(0.41)	(0.01***)	(0.41)	(0.32)	(<0.0001***)	
1994	39	0.0373	0.0029	-0.0004	-0.0452	-0.0221	-0.0047	-0.0918	0.47
		(0.02**)	(0.24)	(0.41)	(0.25)	(0.40)	(0.42)	(<0.0001***)	
1995	39	0.0465	0.0004	-0.0009	-0.0307	0.1071	0.0074	-0.092	0.67
		(0.008***)	(0.45)	(0.23)	(0.30)	(0.03**)	(0.17)	(<0.0001***)	
1996	38	-0.0083	0.0037	-0.0002	-0.0952	-0.0844	-0.0105	0.0430	0.15
		(0.36)	(0.28)	(0.44)	(0.16)	(0.180	(0.19)	(0.16)	
1997	38	0.026	0.0007	0.0005	0.0637	0.2168	-0.0003	-0.0695	0.16
		(0.12)	(0.45)	(0.390	(0.22)	(0.04**)	(0.46)	(0.02**)	
1998	41	-0.0027	-0.0090	0.0007	0.0137	0.0629	0.0033	-0.0006	0.13
		(0.43)	(0.04**)	(0.32)	(0.390	(0.22)	(0.27)	(0.490	
1999	41	-0.0009	-0.0013	-0.0001	0.0082	-0.0369	0.0039	-0.0036	0.04
		(0.48)	(0.40)	(0.47)	(0.43)	(0.29)	(0.21)	(0.44)	
2000	38	-0.0266	0.0015	0.0053	-0.1970	-0.2658	-0.0028	-0.0330	0.34
		(0.23)	(0.41)	(0.05**)	(0.06*)	(0.006***)	(0.39)	(0.22)	
2001	46	0.0231	-0.0019	-0.0004	-0.0883	-0.0124	-0.0028	-0.0407	0.28
		(0.1*)	(0.33)	(0.41)	(0.006***)	(0.44)	(0.17)	(0.04**)	
2002	45	0.0170	-0.0140	0.0016	-0.1196	-0.0582	-0.0135	-0.0468	0.41
		(0.23)	(0.002***)	(0.23)	(0.05**)	(0.12)	(0.09*)	(0.04**)	
2003	52	0.0296	0.0054	-0.0008	-0.0242	0.1173	-0.0174	-0.0460	0.22
		(0.09*)	(0.13)	(0.34)	(0.34)	(0.003***)	(0.1*)	(0.08*)	
Fixed effects	455	0.0235	-0.0018	0.0003	-0.0673	0.0048	-0.0011	-0.0631	0.16
		(<0.0001***)	(0.1*)	(0.29)	(<0.0001***)	(0.28)	(0.28)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is Different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.002	-0.86

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC3 = Signed discretionary accrual, residual from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 18 (Continued)
Robustness Tests of Hypotheses 3: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request
Coefficient (P-value)

Panel D

$DACC4_t = \alpha + \beta_1 REQ_t + \beta_2 SIZE_t + \beta_3 CFO_t + \beta_4 LG\_TAC_t + \beta_5 GROWTH_t + \beta_6 LEV_t + \varepsilon_t$

Year	N	α	β1	β2	β3	β4	β5	β6	R^2
1993	38	0.0536	-0.0055	0.0005	-0.2218	0.0025	0.0132	-0.1031	0.45
		(0.01***)	(0.14)	(0.40)	(0.01***)	(0.39)	(0.28)	(<0.0001***)	
1994	39	0.0374	0.003	0.0003	-0.0487	-0.0141	-0.0054	-0.0917	0.47
		(0.02**)	(0.23)	(0.43)	(0.23)	(0.43)	(0.40)	(<0.0001***)	
1995	39	0.0472	0.0004	-0.0009	-0.0341	0.1057	0.009	-0.0923	0.68
		(0.006***)	(0.46)	(0.22)	(0.28)	(0.03**)	(0.12)	(<0.0001***)	
1996	38	-0.0087	0.0036	-0.0002	-0.0961	-0.0861	-0.0080	0.0428	0.15
		(0.35)	(0.28)	(0.45)	(0.16)	(0.18)	(0.25)	(0.16)	
1997	38	0.0260	0.0006	0.0005	0.0676	0.2190	-0.0004	-0.0703	0.17
		(0.12)	(0.45)	(0.39)	(0.21)	(0.04**)	(0.45)	(0.02**)	
1998	41	-0.0027	-0.0090	0.0007	0.0132	0.0630	0.0034	-0.0006	0.13
		(0.43)	(0.03**)	(0.32)	(0.39)	(0.22)	(0.27)	(0.49)	
1999	41	-0.0010	-0.0014	-0.0001	0.0078	-0.0370	0.0045	-0.0038	0.04
		(0.48)	(0.40)	(0.47)	(0.44)	(0.29)	(0.18)	(0.44)	
2000	38	-0.0266	0.0015	0.0053	-0.1968	-0.2679	-0.0031	-0.0336	0.34
		(0.23)	(0.41)	(0.05**)	(0.06*)	(0.006***)	(0.38)	(0.22)	
2001	46	0.0233	-0.0017	-0.0004	-0.0881	-0.0120	-0.0023	-0.0422	0.28
		(0.1*)	(0.35)	(0.41)	(0.006***)	(0.44)	(0.21)	(0.04**)	
2002	44	0.0271	-0.0135	0.0017	-0.0920	-0.0512	-0.0170	-0.0877	0.44
		(0.12)	(0.002***)	(0.21)	(0.1*)	(0.15)	(0.05**)	(0.01***)	
2003	52	0.0314	0.0055	-0.0009	-0.0353	0.1238	-0.0041	-0.0461	0.24
		(0.07*)	(0.12)	(0.31)	(0.28)	(0.002***)	(0.38)	(0.08*)	
Fixed effects	454	0.0240	-0.0017	0.0004	-0.0658	0.0064	-0.0004	-0.0672	0.16
		(<0.0001***)	(0.12)	(0.26)	(<0.0001***)	(0.21)	(0.42)	(<0.0001***)	

Fama and MacBeth procedure: T-test to determine whether the test variable, REQ is different from zero

Variable	Coefficient Mean	T-statistic
REQ	-0.001	-0.86

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC4 = Signed discretionary accrual, residuals from the following estimation:
$TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 19 reports the results of cross-sectional regressions of discretionary accruals on an indicator variable for the presence of a rate increase request and control variables using a reduced sample which excludes utilities that issue stock. Table 19, Panel A, reports mean coefficients and T-statistics that are computed following Fama and MacBeth procedure. The results indicate that the test variable, *REQ*, has a consistent and significant expected negative sign across all regression models. Mean coefficients (T-statistics) are -0.004 (-1.64), -0.004 (-1.71), -0.006 (-2.84), and -0.006 (-2.85) estimated from model 1, model 2, model 3, and model 4 respectively. The T-statistics are significant at $p<0.05$ in models 1 and 2, and $p<0.01$ in models 3 and 4. These results are consistent with the primary findings in tests of Hypothesis 3. Table 19 Panel B reports results of pooled regressions with fixed time effects. The results reveal that REQ is negative and significant at $p<0.05$ in model 3 and model 4 regressions and insignificant in model 1 and model 2. Results of primary tests of Hypothesis 3, that rate-regulated electric utility firms have lower discretionary accruals in the years they petition for rate increases, hold after the elimination of stock-issuing firms.

Table 20, Panel A reports results of the Fama and MacBeth procedure in the year after a rate request is submitted. Mean coefficients (T-statistics) are -0.009 (-3.59), -0.009 (-3.59), -0.006 (-4.89), and -0.006 (-4.69) estimated from model 1, model 2, model 3, and model 4 respectively. The T-statistics are significant at $p<0.01$ in all the four regression models. Results of pooled cross-sectional regressions with fixed time effects indicate that *REQ* is consistently negative and significant at $p<0.05$. These results suggest that earnings management continues in the year after the rate increase request is submitted. Consistent with earlier discussion, this finding is plausible because regulatory authorities may base rate decisions on futuristic earnings information, that due to the presence of a regulatory lag of about nine months, rate approvals may likely occur in the fiscal year following the submission of a rate increase petition, and, a test period exists for monitoring whether approved rates exceed that allowed for the utility's return on equity (ROE). These propositions are consistent with why utilities may continue to manage earnings in the year after submission of a rate request.

Table 19
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables

Panel A Fama and MacBeth Procedure Results: Mean Coefficient (T-statistic)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.006	0.006	0.013	0.013
		(4.74***)	(4.78***)	(1.26)	(1.19)
Test variable					
REQ	-	-0.004	-0.004	-0.006	-0.006
		(-1.64*)	(-1.71*)	(-2.84***)	(-2.85***)
Controls					
SIZE	-	0.0006	0.0005	0.0015	0.0015
		(0.35)	(0.38)	(1.63*)	(1.63*)
CFO	-	-0.631	-0.633	-0.03	-0.03
		(-7.34***)	(-7.35***)	(-0.97)	(-1.01)
LG_TAC	+	-0.02	-0.027	0.0119	0.0092
		(-0.35)	(-0.5)	(0.21)	(0.16)
GROWTH	+	0.0292	0.0438	-0.005	-0.00076
		(1.74*)	(2.23**)	(0.18)	(-0.14)
LEV	+	-0.034	-0.035	-0.062	-0.06
		(-1.03)	(-1.07)	(-2.34**)	(-2.30**)
R^2		0.54	0.54	0.18	0.17

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 19 (Continued)
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables

Panel B: Results of Fixed Effects Models: Coefficient (p-value)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LE + \sum \alpha_j YDUM_t + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$

Variables	Exp.Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.0804***	0.0801***	0.0171*	0.0162*
		(<0.0001)	(<0.0001)	(0.06)	(0.07)
Test Variable					
REQ	-	0.0018	0.0018	-0.0041**	-0.0042**
		(0.30)	(0.31)	(0.05)	(0.05)
Controls					
SIZE	-	-0.0019	-0.0014	0.0007	0.0007
		(0.15)	(0.16)	(0.24)	(0.23)
CFO	-	-0.6774***	-0.6736***	-0.0461**	-0.0452**
		(<0.0001)	(<0.0001)	(0.04)	(0.04)
LG_TAC	+	-0.0849***	-0.0866**	-0.0464**	-0.0472**
		(0.01)	(0.01)	(0.04)	(0.03)
GROWTH	+	-0.0102**	-0.008*	0.0031	-0.0021
		(0.03)	(0.07)	(0.21)	(0.35)
LEV	+	-0.064***	-0.0653***	-0.0617***	-0.0601***
		(0.001)	(0.001)	(<0.0001)	(<0.0001)
n		348	348	348	348
R^2		0.54	0.53	0.09	0.17

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC1-DACC4 are signed discretionary accruals, signed residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\, \Delta SALES_t + \beta_2\, PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\, PPE_t + \varepsilon_t$ [Modified Jones]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\, \Delta SALES_t + \beta_2\, PPE_t + \beta_3\, CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\, PPE_t + \beta_3\, CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets
YDUM = Year dummy

Table 20

Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year after Request

Panel A: Fama and MacBeth Procedure Results: Mean Coefficient (T-statistic)

Model 1: DACC1 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 2: DACC2 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 3: DACC3 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 4: DACC4 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.056	0.056	0.0088	0.0082
		(4.70***)	(4.72***)	(0.90)	(0.84)
Test variable					
REQ	-	-0.009	-0.009	-0.006	-0.006
		(-3.59***)	(-3.59***)	(-4.89***)	(-4.69***)
Controls					
SIZE	-	0.00011	0.00025	0.0011	0.0011
		(-0.08)	(-0.18)	(1.61*)	(1.58*)
CFO	-	-0.655	-0.648	-0.04	-0.041
		(-7.30***)	(-7.36***)	(-1.47*)	(-1.50*)
LG_TAC	+	-0.062	-0.07	-0.015	-0.017
		(-1.32)	(-1.52*)	(-0.31)	(-0.36)
GROWTH	+	0.0417	0.0545	0.0018	0.0071
		(2.53***)	(2.67***)	(0.36)	(1.11)
LEV	+	-0.014	-0.013	-0.044	0.042
		(-0.47)	(-0.44)	(-1.79**)	(-1.73*)
# years		11	11	11	11
R^2		0.56	0.50	0.09	0.08

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta SALES_t + \beta_2\ PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ (\Delta SALES_t - \Delta REC_t) + \beta_2\ PPE_t + \varepsilon_t$ [Modified Jones Model]
DACC3: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ \Delta\ SALES_t + \beta_2\ PPE_t + \beta_3\ CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\ (1/ASSETS_{t-1}) + \beta_1\ (\Delta\ SALES_t - \Delta REC_t) + \beta_2\ PPE_t + \beta_3\ CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as total debt divided by total assets

Table 20 (Continued)
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year after Request

Panel B: Results of Fixed Effects Models: Coefficient (p-value)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.0597***	0.0569***	0.0116	0.0107
		(<0.0001)	(<0.0001)	(0.12)	(0.14)
Test Variable					
REQ	-	-0.0058**	-0.0058**	-0.0061***	-0.0061***
		(0.04)	(0.04)	(0.006)	(0.005)
Controls					
SIZE	-	-0.0012	-0.0011	0.0008	0.0008
		(0.19)	(0.20)	(0.20)	(0.20)
CFO	-	-0.6822***	-0.6673***	-0.0323*	-0.0301*
		(<0.0001)	(<0.0001)	(0.09)	(0.1)
LG_TAC	+	-0.0732**	-0.0762**	-0.0275	-0.0274
		(0.02)	(0.02)	(0.13)	(0.14)
GROWTH	+	-0.008*	-0.0048	-0.0026	-0.0013
		(0.06)	(0.18)	(0.24)	(0.36)
LEV	+	-0.052***	-0.0475***	-0.0512***	-0.0488***
		(0.004)	(0.008)	(0.0002)	(0.0002)
n		361	361	361	361
R^2		0.56	0.50	0.09	0.08

***, **, * denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets.
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as Total debt divided by total assets
YDUM = Year dummy

Table 21 reports results of cross-sectional estimations in the second year after the rate request is submitted. Results from all the four regression models and from both Fama and MacBeth and pooled cross-sectional regressions with fixed time effects indicate that the coefficient for the test variable, *REQ*, is indistinguishable from zero. As was the case in primary findings, earnings management appears to abate (i.e., reversing accruals) in the second year after the rate request.

Table 22 reports results in the year prior to the rate increase submission. Results of both the Fama and MacBeth procedure and pooled cross-sectional regressions with fixed time effects reveal that the sign of the test variable, *REQ*, is indistinguishable from zero. This finding provides evidence that utilities do not manage earnings in the year prior to the submission of a rate increase request. This is consistent with the finding in primary tests.

The results of these robustness tests provide evidence that primary results on tests of Hypothesis 3 are not sensitive to elimination of firms with a competing capital market incentive for earnings management.

5.2.4 Summary of Hypothesis 3 Results

Table 23 depicts a summary of the earnings management variable, *REQ*, across time for sample two utilities. Table 23 Panel A, reports a time-line of earnings management using the Fama and MacBeth cross-sectional regression results. These results reveal that there is no evidence of earnings management in the year prior to submission of the rate request. Similarly, there is no evidence of earnings management in the second year after a rate request is submitted. The results also indicate that there appears to be downward earnings management in the year a rate request is submitted and in the following year.

Table 21

Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request

Panel A: Fama and MacBeth Procedure Results: Mean Coefficient (T-statistic)

Model 1: DACC1 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 2: DACC2 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 3: DACC3 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε
Model 4: DACC4 = $\alpha + \beta_1$REQ + β_2SIZE + β_3CFO + β_4LG_TAC + β_5GROWTH + β_6LEV + ε

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.048	0.047	0.0089	0.008
		(4.67***)	(4.78***)	(0.89)	(0.81)
Test variable					
REQ	-	-0.001	-0.001	0.002	0.002
		(-0.30)	(-0.40)	(0.56)	(0.54)
Controls					
SIZE	-	0.0006	0.0005	0.0011	0.0011
		(0.39)	(0.37)	(1.36*)	(1.38*)
CFO	-	-0.65	-0.642	-0.038	-0.038
		(-6.68***)	(-6.74***)	(-1.12)	(-1.13)
LAG_TAC	+	-0.082	-0.088	-0.008	-0.009
		(-1.70*)	(-1.79**)	(-0.17)	(-0.18)
GROWTH	+	0.0359	0.0496	-0.001	0.0034
		(2.21**)	(2.47**)	(-0.32)	(0.79)
LEV	+	-0.015	-0.014	-0.045	-0.044
		(-0.49)	(-0.44)	(-1.85**)	(-1.81**)
R^2		0.56	0.55	0.11	0.07

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test)
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones Model]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE = Natural log of total assets
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV = Leverage defined as total debt divided by total assets

Table 21 (Continued)
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Second Year After Request

Panel B: Fixed Effects Model Results: Coefficient (p-value)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_j YDUM_t + \varepsilon$

ariables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.0548***	0.0523***	0.0099	0.0089
		(<0.0001)	(0.0002)	(0.18)	(0.20)
Test Variable					
REQ	+	-0.0032	-0.0031	0.0000	0.0000
		(0.19)	(0.20)	(0.49)	(0.47)
Controls					
SIZE	-	-0.0007	-0.0007	0.0009	0.0009
		(0.32)	(0.38)	(0.19)	(0.40)
CFO	-	-0.6881***	-0.6726***	-0.0321*	-0.0299
		(<0.0001)	(<0.0001)	(0.1)	(0.12)
LAG_TAC	+	-0.0908***	-0.0909***	0.0310	-0.0311
		(0.006)	(0.007)	(0.12)	(0.12)
GROWTH	+	-0.0085**	-0.0054	-0.0027	-0.0011
		(0.05)	(0.16)	(0.25)	(0.36)
LEV	+	-0.052***	-0.0475***	-0.053***	-0.0506***
		(0.005)	(0.01)	(0.0002)	(0.0004)
n		334	334	334	334
R^2		0.56	0.55	0.11	0.07

***, **, * denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE =Natural log of total assets.
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as Total debt divided by total assets
YDUM = Year dummy

Table 22
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request

Panel A: Fama and MacBeth Procedure Results: Mean Coefficient (T-statistic)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon$

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept	?	0.056	0.058	0.007	0.0064
		(4.86***)	(5.05***)	(0.69)	(0.63)
Test variable					
REQ	-	0.0025	0.0026	0.0008	0.0008
		(0.80)	(0.84)	(0.30)	(0.30)
Controls					
SIZE	-	0.00027	0.00034	0.0012	0.0012
		(-0.20)	(-0.25)	(2.63***)	(2.68***)
CFO	-	-0.567	-0.573	0.0023	0.0014
		(-6.61***)	(-6.68***)	(0.12)	(0.07)
LG_TAC	+	-0.085	-0.089	-0.004	-0.003
		(-1.39*)	(-1.52*)	(-0.06)	(-0.06)
GROWTH	+	0.0206	0.0342	-0.004	0.00028
		(1.46*)	(1.95**)	(-1.34)	(-0.06)
LEV	+	-0.027	-0.03	-0.05	-0.049
		(-0.79)	(-0.89)	(-1.61*)	(-1.57*)
R^2		0.55	0.55	0.08	0.08

***, **, * denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE =Natural log of total assets.
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as Total debt divided by total assets

Table 22 (Continued)
Tests of Hypothesis 3 on Reduced Sample: Results of Cross-Sectional Regression of Discretionary Accruals on an Indicator Variable for the Presence of a Rate Increase Request Plus Control Variables in the Year Prior to Request

Panel B: Fixed Effects Model Results: Coefficient (p-value)

Model 1: $DACC1 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon$
Model 2: $DACC2 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon$
Model 3: $DACC3 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon$
Model 4: $DACC4 = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon$

Variables	Exp. Sign	Model 1	Model 2	Model 3	Model 4
Intercept		0.0907***	0.0911***	0.0172*	0.0167*
		(<0.0001)	(<0.0001)	(0.06)	(0.06)
Test Variable					
REQ		0.0005	0.0009	0.0003	0.0003
		(0.44)	(0.40)	(0.40)	(0.44)
Controls					
SIZE		-0.0025**	-0.0025**	0.0001	0.0001
		(0.04)	(0.04)	(0.46)	(0.46)
CFO		-0.6669***	-0.6651***	-0.0301*	-0.0291*
		(<0.0001)	(<0.0001)	(0.1)	(0.1)
LG_TAC		-0.0936***	-0.0946***	-0.0533**	-0.0528**
		(0.006)	(0.006)	(0.02)	(0.02)
GROWTH		-0.0104**	-0.0084**	-0.0026	-0.0016
		(0.02)	(0.05)	(0.24)	(0.33)
LEV		-0.0633***	-0.0666***	-0.0566***	-0.0555***
		(0.002)	(0.002)	(0.0002)	(0.0002)
n		333	333	333	333
R^2		0.55	0.55	0.08	0.08

***, **, * Denote significance at 0.01, 0.05, and 0.1 respectively (one-tailed test).
DACC1-DACC4 are signed discretionary accruals, residuals from the following estimations:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$ [Jones Model]
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$ [Modified Jones]
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Jones +CFO Model]
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$ [Mod. Jones + CFO Model]
REQ = Dummy variable equal to one if a firm requested a rate increase in year t; zero otherwise
SIZE =Natural log of total assets.
CFO = Cash flow from operations scaled by lagged assets
LG_TAC = Lagged total accruals scaled by lagged assets
GROWTH = Sales growth
LEV =Leverage defined as Total debt divided by total assets
YDUM = Year dummy

Table 23
Summary of Regression Results on Full Sample for Earnings Management Variable (REQ) Across Time

Panel A: Fama and McBeth Procedure Results (T-statistics are reported below Mean Coefficients)

$DACC = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon_t$

	Time (t-1)	Time (t)	Time (t+1)	Time (t+2)
DACC 1	-0.0006	-0.006**	-0.005	-0.003
	-0.50	-2.41	-2.20***	-1.26
DACC 2	-0.0007	-0.005	-0.006	-0.003
	-0.55	-2.27**	-2.47**	-1.18
DACC 3	-0.002	-0.007	-0.007	-0.003
	-0.86	-4.28***	-3.31***	-1.27
DACC 4	-0.001	-0.007	-0.007	-0.003
	-0.86	-4.54***	-3.30***	-1.25

Panel B: Results of Fixed Effects Regression Models (p-values are reported below coefficient estimates)

$DACC = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon_t$

	Time (t-1)	Time (t)	Time (t+1)	Time (t+2)
DACC 1	-0.0009	-0.002	-0.005***	-0.0037*
	0.33	0.15	0.01	0.06
DACC 2	-0.0009	-0.002	-0.0052***	-0.0032*
	0.34	0.15	0.01	0.09
DACC 3	-0.0018	-0.005***	-0.0059***	-0.0034**
	0.11	0.0002	<0.0001	0.015
DACC 4	-0.0017	-0.006***	-0.0059***	-0.0033**
	0.12	<0.0001	<0.0001	0.018

DACC1 – DACC4 are residuals from the following models:
DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta SALES_t + \beta_2\,PPE_t + \varepsilon_t$
DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \varepsilon_t$
DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,\Delta\,SALES_t + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$
DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta\,SALES_t - \Delta REC_t) + \beta_2\,PPE_t + \beta_3\,CFO_t + \varepsilon_t$
Time(t-1) = Year prior to rate increase request
Time (t) = Year of rate increase request
Time (t+1) = Year after rate increase request
Time (t+2) = Second year after rate increase request

These results, using all sample firms, indicate more evidence of earnings management in the year a rate increase request is submitted than in the following year.

Table 23, Panel B reports results of pooled regressions with fixed effects for sample two utilities. The results are consistent with those of Panel A in that there is more evidence of earnings management in the year a rate request is submitted than the following year. However, results also reveal that earnings management appears to continue in the second year after a rate request is submitted, but declining in statistical significance.

Table 24, Panel A reports results of the Fama and MacBeth procedure applied to the reduced sample (after eliminating firms with a capital market incentive). The results are consistent with those for the full sample in that evidence of earnings management exists in the year a rate request is submitted and the following year. No evidence of earnings management is observed in either the prior year to or the second year after the rate increase request is submitted. These results further indicate that there is statistically stronger evidence of earnings management in the year after a rate request is submitted than in the year in which the rate request is actually submitted. Results presented in Panel B (pooled regressions with fixed effects) also indicate stronger evidence of earnings management in the year following a rate request.

I draw several inferences from these results. First, utilities appear to manage earnings by decreasing accruals in the year they submit requests for rate increases and the year that follows. Secondly, as depicted by Fama and MacBeth procedure results, there is statistically stronger evidence of earnings management for utilities that do not issue stock in the year after a rate increase request is submitted than the year in which it is actually submitted. Third, there is no evidence of earnings management either in the year prior to the submission of a rate request or in the second year after the submission is made.

Table 24
Summary of Regression Results on Reduced Sample for Earnings Management Variable (REQ) Across Time

Panel A: Fama and MacBeth Procedure Results (T-statistics are reported below mean coefficient estimates)

$$DACC = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \varepsilon_t$$

	Time (t-1)	Time (t)	Time (t+1)	Time (t+2)
DACC 1	0.0025	-0.004	-0.009	-0.001
	0.80	-1.64*	-3.59***	0.30
DACC 2	0.0026	-0.004	-0.009	-0.001
	0.84	-1.71*	-3.59***	0.40
DACC 3	0.0008	-0.006	-0.006	0.002
	0.30	-2.84***	-4.89***	0.56
DACC 4	0.0008	-0.006	-0.006	0.002
	0.30	-2.85***	-4.69***	0.54

Panel B: Results of Fixed Effects Regression Models (p-values are reported below coefficient estimates)

$$DACC = \alpha + \beta_1 REQ + \beta_2 SIZE + \beta_3 CFO + \beta_4 LG\_TAC + \beta_5 GROWTH + \beta_6 LEV + \sum \alpha_{,j} YDUM_t + \varepsilon_t$$

	Time (t-1)	Time (t)	Time (t+1)	Time (t+2)
DACC 1	0.0005	0.0018	-0.0058**	-0.0032
	0.44	0.3	0.04	0.19
DACC 2	0.0009	0.0018	-0.0058**	-0.0031
	0.40	0.31	0.04	0.20
DACC 3	0.0003	-0.0041**	-0.0061***	0.0000
	0.40	0.05	0.006	0.49
DACC 4	0.0003	-0.0042**	-0.0061***	0.0000
	0.44	0.05	0.005	0.47

DACC1 – DACC4 are residuals from the following models:

DACC1: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\, \Delta SALES_t + \beta_2\, PPE_t + \varepsilon_t$

DACC2: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1(\Delta SALES_t - \Delta REC_t) + \beta_2\, PPE_t + \varepsilon_t$

DACC3: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\, \Delta SALES_t + \beta_2\, PPE_t + \beta_3\, CFO_t + \varepsilon_t$

DACC4: $TAC_t = \alpha\,(1/ASSETS_{t-1}) + \beta_1\,(\Delta SALES_t - \Delta REC_t) + \beta_2\, PPE_t + \beta_3\, CFO_t + \varepsilon_t$

Time(t-1) = Year prior to rate increase request
Time (t) = Year of rate increase request
Time (t+1) = Year after rate increase request
Time (t+2) = Second year after rate increase request

Fourth, electric utilities appear to use long-term accruals to manage earnings and these accruals are observed to reverse gradually rather than immediately. This inference is consistent with that observed in examining the significance of regulatory assets in the discretionary accrual models (Table 12).

6. SUMMARY AND CONCLUSIONS

This study represents the first broad-based examination of earnings management within the U.S. rate-regulated electric utility industry and provides empirical evidence regarding the adequacy of regulatory scrutiny in precluding this manipulation. This represents one of the study's primary contributions. The study's results also provide empirical justification for accounting researchers to exclude rate-regulated firms from cross-sectional, inter-industry research designs that use the discretionary accrual metric to investigate earnings management.

Three research questions are addressed. First, does the magnitude of earnings management in rate-regulated electric utilities, as represented by discretionary accruals, significantly differ from that observed in comparable non-regulated companies? Using both time series and cross-sectional research designs, I observe the discretionary accruals of rate-regulated utilities to be significantly smaller in absolute value than those of comparable manufacturing firms (Tables 5 and 7). Indeed, the signed discretionary accruals for utilities, on average, are not found to be significantly different from zero. This is consistent with regulatory scrutiny reducing the opportunities for earnings management, and supports the proposition that, on average, regulatory monitoring is adequate in this regard. Robustness tests indicate that a possible structural shift due to deregulation in 1999 does not alter the findings from the time series design. Likewise, the elimination of firms that submitted rate requests from the sample to eliminate confounding explanations, does not significantly change the primary findings.

The second question examines whether deregulatory forces that affected some regulatory jurisdictions in the late 1990s, increased the opportunities for earnings management. Results from this study (Tables 8 and 9) provide some evidence that this, in fact, happened. The discretionary accruals of utilities in those jurisdictions that undertook some deregulatory action over the sample period, increased in the post-1999 period. This is consistent with relaxed regulatory scrutiny and increased economic incentives associated with deregulation; this environment may have provided managers increased opportunities and motivation to engage in earnings management.

The third research question focuses on whether rate-regulated electric utilities manage earnings downward in the year they file for rate increases. Although, as stated earlier, signed discretionary accruals for utilities are not significantly different from zero on average, this may not be the case for particular periods when a rate request is being considered by regulators. During these years, utilities requesting rate increases have significantly smaller discretionary accruals than in years when no requests are made. Robustness tests indicate that discretionary accruals continue to be smaller in the year following the year of a rate request, only to become statistically insignificant in the second year after the request. These results are consistent with opportunistic earnings management both in the year a rate increase request is submitted and the following year. Results indicating that earnings management continues in the year after a rate request is submitted are not consistent with an immediate reversal of accruals. The implication is that electric utilities do not manage earnings through the use of working capital accruals that reverse immediately, but instead use long-term accruals that take longer to reverse. Earnings management in the year following the submission of a rate request is plausible for two reasons. First, rate approvals are decided approximately nine months after submission of a rate request; this lag may well result in a spill-over to the next fiscal year. Second, there is a likelihood of PUCs using projected rather than historical earnings information in rate decisions. Additional tests are inconclusive regarding electric utilities' use of regulatory assets in accrual management.

Regulatory scrutiny may be adequate in curtailing any potential abuse of the accrual discretion granted by the FASB to rate-regulated electric utilities in sanctioning the use of regulatory assets.

Although regulators may take comfort in the study's finding that "on average" there is no evidence of earnings management using discretionary accruals, they should also note the unintended consequences of retail deregulation.

Also, if management can depress earnings in order to bolster their requests for increasing rates, regulators should be fully aware of the potential for receiving biased earnings information. This might lead to increased regulatory (monitoring) costs. Finally, because operating costs are "passed through" to ratepayers under rate regulation, increasing costs in order to decrease earnings increases the amount passed through which must be covered in rates. However, this increase is only a second-order effect; the primary effect being that if regulators are persuaded to increase the price of electricity by increasing the allowed rate of return. Unlike non-regulated earnings management studies, this raises the social welfare issue of a wealth transfer between ratepayers (customers) and shareholders. Providing empirical evidence consistent with this argument provides a unique contribution to the literature.

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Joseph Ben Omonuk earned his Bachelor of Commerce/Accounting (Upper Division) Honors and an MBA at Makerere University, Kampala. He received an award for obtaining the highest grades in the MBA program. Mr. Omonuk is a professional accountant and a member of Association of Chartered Certified Accountants (ACCA), a global accounting body based in the United Kingdom. He was a Senior Lecturer and Head of the Department of Accounting at Makerere University Business School for four years prior to enrolling in the doctoral program. During that period, he was a member of the Makerere University Senate. He served diligently in this position and was awarded a certificate of recognition for exemplary performance. He received an Exxon Mobil scholarship award for two consecutive years in recognition of his outstanding academic performance in the Ph.D. program at Louisiana State University. During his doctoral studies, he taught financial accounting principles, cost accounting and international accounting courses at Southern University. In his professional accounting career, Mr. Omonuk has successfully conducted consultancy projects involving the electric utility industry and government that were funded by the World Bank. He has also worked with the "Big Four" international accounting firms in the placement of Makerere University undergraduate accounting students. He briefly worked as an accountant in the Treasury Department, Ministry of Finance in Uganda. He will receive the degree of Doctor of Philosophy in August 2007.